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June 30, 2015

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI)
2015 System Extension Application

FEI hereby applies to the British Columbia Utilities Commission (the Commission) for approval of its 2015 System Extension Application, pursuant to Commission Letter L-6-15.

If further information is required, please contact Brent Graham at 604-592-7857.

Sincerely,

FORTISBC ENERGY INC.

Original signed by: Ilva Bevacqua

For: Diane Roy

Attachments

cc (email only): Workshop Participants

FortisBC Energy Inc.

2015 System Extension Application

Volume 1 - Application

June 30, 2015

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1. INTRODUCTION AND OVERVIEW

The main extension test (MX Test, the Test, Economic Test or System Extension Test) serves as a practical means for determining whether a main extension to the Company's distribution system will be economic. It is a financial evaluation applied at the time a system extension is contemplated to determine whether or not a main extension can proceed without contribution in aid of construction (CIAC) from the customer wishing to connect to the Company's distribution system. The purpose of the Test is to ensure the needs of new customers are balanced with the needs of existing customers. To this end, the Test is intended to ensure that new customers are not unduly burdened with attachment costs and existing customers are not exposed to undue costs from the attachment of the new customers.

The Test is a discounted cash flow (DCF) analysis that considers the revenues and costs associated with a planned main extension over a 20 year period, discounted at a rate based on FEI's weighted average cost of capital. The DCF approach has been used since the inception of the test in 1993. The service line cost allowance (SLCA) is derived from the Test and also serves as a financial evaluation tool to be applied at the time a system extension is contemplated to determine whether or not a service line can proceed without a CIAC. The SLCA has similarly existed in its basic form for many years, with periodic updates.

FEI has undertaken an evaluation of the MX Test to ensure that the test remains appropriate in light of the present conditions, and strikes a fair balance among existing and new customers. It involved a review of the mechanisms in conjunction with an expert (EES Consulting) and stakeholder engagement.

As a result of the review, the Company concluded:

- The DCF methodology continues to be the most appropriate approach for the Test, including the key Profitability Index (PI) parameters (0.8 individually, and 1.1 in aggregate). However, some of the parameters of the existing Test can and should be modified to provide greater choice regarding access to natural gas in appropriate circumstances without undue burden to existing customers.
- The Commission's focus in annual reporting appears to have shifted over time. Annual reporting has become less focussed on FEI's compliance with the MX Test, and more focussed on a hindsight review of whether FEI should have undertaken particular extensions. The reporting requirements have become more onerous over time in tandem with the shift in focus. There is a need for the Commission to articulate a clear objective for the reporting, and revisit the reporting framework in light of that objective. FEI submits:
    - A fundamental issue with the apparent shift in focus is that the evaluations currently being required by the Commission (i.e., re-running the MX Test for particular extensions after the fact with new information) are not a legitimate basis for assessing the prudence of FEI's decision to construct a main extension. Prudence can only be assessed by reference to whether or not FEI complied with

the approved MX Test based on information reasonably available to FEI at the time the decision was made to construct the extension.

- Re-running the MX Test for particular extensions after the fact with new information also does not provide a reasonable basis for assessing whether the extension is economic or adversely affecting existing customers. The assessment is really comparing two point in time forecasts, with the updated forecast occurring as little as one year into the 50+ year service life. It is not measuring the likely economic impact of a main extension on customers over the life of the extension. A variance from the original forecast can arise from a variety of market-related or other factors, and may reflect a timing difference only. Moreover, the results of the assessment can be misleading, as a direct result of the unrealistic assumptions implicit in the re-run MX Test.[1]
- It would be more efficient, and more consistent with the spirit of the Core Review, to re-focus annual reporting on FEI's compliance with the MX Test. The assessment of whether or not the MX Test is achieving its intended result is best conducted in a separate less frequent review based on a more analytically sound approach. EES Consulting, in conjunction with FEI, has developed a reasonable means of assessing the economics of past extensions so as to permit a reasonable assessment of how the Test is performing.

This filing also addresses the concerns that have been raised by the Commission about the MX Test and how FEI is implementing it. FEI has included Section 5 to deal directly with those comments, although some of the supporting information appears throughout the filing. FEI makes several points in Section 5, including that the method by which the Commission reached its conclusion that existing customers may have been exposed to undue cost burden from past extensions (re-running MX Tests for certain extensions) could not have provided the necessary information to determine the cost-effectiveness of main extensions. The data used in that analysis was also skewed by the market impacts of the 2008 and 2009 recession and by the parameters and assumptions employed in the Commission's assessment approach. EES Consulting's analysis demonstrates that existing customers of FEI have benefitted from the addition of new customers in recent years.

1.1 *APPROVALS SOUGHT*

In this Application, the Company seeks approval for the following:

1. Effective January 1, 2016, with respect to FEI's MX Test:

[1] One such assumption, for example, is that the Commission's approach assumes that no attachments will occur after the fifth year. As discussed in Section 3.4.2.2 the experience with extensions undertaken in 2008 and 2009 demonstrates the potential distortions associated with such assumptions. The recession resulted in delaying a number of additions to year six.

a. The discontinued the use of the 20 year term and the application of a 40 year Discounted Cash Flow term for use in the MX Test.

b. The consideration of a 10 year horizon for customer attachments in circumstances when the existence of a long term plan for growth that exceeds 5 years can be reasonably demonstrated.

c. The application of the sliding-scale methodology as proposed in the Application to calculate the overhead rate for main extensions where capital costs are forecast to be greater than $25,000.

d. The Discontinued application of the +10% and +15% Energy Efficiency Consumption credits for customers with high efficiency and LEED certified appliances.

2. Effective January 1, 2016, with respect to FEI's Customer Connection Policy:

a. An updated Service Line Cost Allowance amount of $2,150.00 for single family dwellings and $4,000.00 for duplexes.

b. The annual update of the SLCA amounts using the approved methodology in November, for implementation January 1 of the following year is approved.

c. The establishment of the System Extension Fund of $1.0 Million, to be recovered through gas delivery rates and included in rate base each year as an offset to Contributions in aid of Construction.

3. Effective with the reporting on 2015 main extensions:

a. The discontinued use of the current MX reporting requirements.

b. To provide a Report to the Commission at the end of the first quarter for the preceding year's main extensions that includes:

i. The total number of main extensions completed, including the total actual costs for main extensions completed; the forecast PI for all main extensions in aggregate; the total number of customers providing a CIAC, including the total dollar value of CIAC. For main extensions using a 10-year customer addition forecast period, the number of main extensions, the actual costs and the total number and dollar value of CIAC will be provided separately from the total main extensions.

ii. The total number of approved requests to access the System Extension Fund, including the total dollar value of the approved requests; and

iii. Updated MX Test input parameters consistent with approved practices, for implementation January 1 of the following year.

A draft form of order is included in Appendix E-1, and a blackline version of the proposed tariff changes is included in Appendix E-2.

1.2 *PROPOSED REGULATORY PROCESS*

FEI believes that a Streamlined Review Process, including one round of Information Requests from the Commission and Interveners, will provide for an appropriate and efficient review for this Application. The Company proposes the following regulatory schedule.

ACTION	DATE (2015)
Application Filed	Tuesday, June 30
Commission Issues Procedural Order	Week of July 13
Intervener Registration	Monday, July 27
Commission Information Request No. 1	Monday, August 10
Intervener Information Request No. 1	Monday, August 17
FEI Response to Information Requests No. 1	Friday, September 4
Streamlined Review Process	Late September 2015

Based on the proposed schedule, FEI anticipates it would be able to implement the approved changes to its policies and tariffs by January 1, 2016.

FEI submits that this filing is ideally suited for an SRP for the following reasons.

- First, the limited modifications to the MX Test and SLCA are technical issues most efficiently addressed in a discussion format with the benefit of subject matter experts present.
- Second, the MX Test has spawned a significant amount of regulatory process and reporting over many years. Some of the same issues - particularly around the nature of the reporting, how it is applied, and how the results are interpreted - arise time and again. The written processes have thus far failed to resolve a root cause of these issues, which is a fundamental difference of opinion regarding the logic and efficacy of how the Commission has come to use the reporting over time. It is in the interests of all concerned to try a new approach to reach a common understanding about, and resolve, the root issues. FEI strongly believes that the root issues could be resolved once and for all if it is able to bring its subject matter experts to a SRP to discuss the issues directly with the Commission Panel. A back and forth exchange with the Commission and stakeholders will be much more likely than a written process to promote mutual understanding of the nuances of the issues.

- Third, as seen in the letters included in Appendix C, the stakeholders involved in the review of our system extension polices were highly engaged and supportive of the consultative process. Involving these stakeholders in an SRP would be a logical extension of this consultation process.

1.3 *ORGANIZATION OF THE APPLICATION*

The Application is organized into the following sections:

Section 2 - Background

This section discusses the origins of the Company's existing system extension regulatory constructs dating back to 1993, including the MX Test, the SLCA and CIAC that have all been approved by the Commission for many years and continue to serve their intended purposes.

Section 3 - System Extension Policy Review

Consistent with past practices of periodically updating FEI's system extension polices, the Company conducted a review of its policies. The Company believed there was a need to consider possible changes to the Company's policies to reflect the passing of time. More specifically, there were three main reasons for the review:

1. Customers wanted FEI to examine potential barriers to accessing natural gas service;
2. The Company had identified several potential enhancements to its current system extension policies; and
3. There were opportunities to improve MX reporting and evaluation practices.

The Company has since completed the review. In this section, the Company describes the major outcomes of the process, while in the following section, the Company provides recommendations in response to the findings of the review.

Section 4 - Recommendations

This section describes the analyses and recommendations relating to the MX Test, the SLCA, CIAC and revised MX reporting.

Section 5 - Response to Commission Letters L-34-14 and L-44-14

In Letters L-34-14 and L-44-14, the Commission encouraged the Company to complete its system extension policy consultation with stakeholders and Commission staff, to address a number of system extension policy related concerns including providing a new reporting and evaluation methodology, and to file an Application by the end of the first quarter of 2015. In this section, the Company indicates it has successfully completed a consultative process with stakeholders and Commission staff and discusses its responses to the concerns raised in the letters.

2. BACKGROUND

The following section provides the salient background of FEI's system extension policies and practices and the development of the MX Test from 1993 to the present. It begins with a review of the regulatory history, and then offers an overview of the current system extension constructs including the MX Test, the SLCA and CIAC. It has been the Company's past practice to periodically review its system extension policies in response to changes in the marketplace, the needs of customers and the direction of the Commission.

2.1 *SYSTEM EXTENSION REGULATORY HISTORY*

This section discusses the regulatory history between 1993 and 2008 that shaped the MX Test and SLCA as applied today.

2.1.1 1993 Phase B Rate Design Application and Order G-101-93 and Accompanying Decision

In 1988, with the expansion of the Company following the acquisition of the Lower Mainland natural gas assets from BC Hydro, there were four different geographically based divisions[2] and three separate system connection policies and main extension tests (BC Gas MX Tests). The three separate BC Gas MX Tests were disparate in design and methodology, which resulted in customers being treated differently when seeking to attach to the Company's distribution system simply due to their geographic location. In 1993, FEI sought approval in its Phase B Rate Design Application (1993 Rate Design Application) to consolidate its Lower Mainland, Inland and Columbia Divisions (the Divisions)[3], in part to address two concerns related to the BC Gas MX Tests that had been expressed by the Commission in its 1992 Revenue Requirement Decision accompanying Order G-63-92:

1. If the current main extension tests are not reasonable, existing customers may be subsidizing new customers; and
2. Whether the Company has been applying the main extension tests on a consistent basis.

In designing a main extension policy and MX test to address the Commission's concerns, the Company was guided by a number of factors at that time that remain relevant today. From a policy perspective, the Company recognized that the widespread availability of natural gas could be a significant factor in the economic development of BC and that natural gas would be a cleaner alternative to other fuel sources such as oil, wood and coal.[4] From the financial perspective of ratepayers, the Company needed to balance the interests of the new customers

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[2] Divisions included Lower Mainland, Inland, Columbia and Fort Nelson.

[3] The Company's pproposal to consolidate Fort Nelson was made in the 1992 Revenue Requirement Application; the consolidation was denied by Order G-63-92.

[4] 1993 RDA Tab 13 p. 8.

in obtaining natural gas with the interests of existing customers. The Company thus aimed to design an MX test that was able to capture both the costs and future benefit of a main extension based on the life of the particular asset being installed. That is, the Company considered that it was important to reflect the fact that although a main extension required up-front investment; it would continue to generate benefits for the life of the assets.

The Company proposed an MX Test based on a DCF analysis that calculated a benefit-to-cost ratio to assess the economic viability of a main extension. The Test compared the net present value (NPV) of estimated gross revenues over the expected life of 50 years for a main extension, with the NPV of the estimated capital costs for a main extension over the first five years of its installation. Estimated gross revenues were calculated exclusive of the cost of gas and were determined based on a number of factors including the premise types the main was expected to serve and the level of saturation of attachments (and associated consumption) expected over the life of the main extension[5]. Estimated capital costs were determined based on expenditures required for mains, services, meters and other project specific costs for the first 5 years of the main extension.

Under the test, the economic viability of a main extension was indicated by a benefit-to-cost ratio equal to or greater than 1.0. If the revenues (benefit) from a main extension as shown by the test were insufficient to meet the cost of the main extension as indicated by ratio less than 1.0, then a CIAC may be required from the customer[6]. The Company proposed that a customer contribution would be required for an individual main extension if the benefit-to-cost ratio was below 0.6, but in aggregate, the Company proposed that the benefit-to-cost ratio for all main extensions undertaken for any given year are to be greater than or equal to 1.0. The rationale for this was that if the aggregate of all main extensions in a particular year produced a benefit-to-cost ratio of 1.0 or more, existing customers would not be negatively impacted from a financial standpoint by the construction of the planned main extensions.

The proposal set out in the 1993 Rate Design Application formed the basis for the MX Test that still applies today.

By Order G-101-93, the Commission accepted the DCF-based MX Test proposed by the Company, with modifications that included[7]:

- The use of a minimum benefit-to-cost ratio of 1.0 as the acceptance criterion[8] for each proposed main extension;

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[5] 1993 RDA Tab 13, p. 11-12.

[6] The Company proposed that in situations where the size of the main installed is larger than that necessary to serve existing customers to accommodate future growth, the Company would waive some or all of any CIAC. Moreover, the Company proposed to waive contributions of less than $100.00 per customer, and in instances where more customers connect to the extension within the first 5 years of the main extension, the Company would offer pro-rated refunds based on the difference between the original and actual number of customer additions.

[7] Decision accompanying order G-101-93, p. 30.

[8] The benefit to cost ratio is often referred to as the Profitability Index (PI) threshold. For example, in a hypothetical MX Test that has as PI of less than 1.0, the customer must pay a CIAC to reach the 1.0 PI threshold in order for the project to proceed.

- A revenue forecast calculation based on the 33 year depreciation life of meters; and
- The inclusion of full overheads in the main extension cost projections.

The approved changes to the MX Test were reflected in the Company's tariff effective January 1, 1994.

In the Decision accompanying Order G-101-93, the Commission also expressed that a consistent set of evaluative criteria should be generally applied to the Company's investments and directed the Company to align the MX Test more explicitly with the criteria applied in its Integrated Resource Plan (IRP)[9]. Refinements to the Test, however, were not made until after the Commission's 1996 generic proceeding on utility tests for approving system extensions, which is discussed in the next section.

2.1.2 1996 BCUC Generic Hearing on System Extension Policy and the Utility System Extension Test Guidelines and Commission Decision & Order G-80-96

In response to several applications from separate utilities regarding issues related to system extension policy, the Commission initiated a generic hearing into the main extension policy and economic tests of the natural gas and electrical distribution utilities in BC[10] in 1995 by order G-50-95[11]. The purpose of the generic proceeding was to determine the extent to which the system extension policies that existed amongst the distribution utilities could be better aligned and improved for fairness and efficiency[12]. The proceeding explored a number of approaches under which a system extension could be evaluated and the appropriate methods and time periods for which required contributions could be required. The proceeding also contemplated the various inputs to the MX test that could be required and how they would be applied. The proceeding concluded with the Commission's Phase II Reconsideration Decision and Order G-80-96 issued on August 13, 1996[13] (the Phase II Reconsideration Decision) and the subsequent issuance of the Utility System Extension Test Guidelines (the Guidelines) on September 5, 1996. The purpose of the Guidelines was to provide a degree of consistency and assistance to utilities with regard to the approach to the design of system extension tests by individual utilities. The Guidelines, which remain in force today, are as follows[14]:

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[9] Decision accompanying Order G-101-93, p. 29.

[10] BC Hydro, West Kootenay Power Ltd., BC Gas Utility Ltd. (formerly BC Gas Inc.), Centra Gas British Columbia Inc., Princeton Light and Power Company Ltd., and Pacific Northern Gas Ltd. were directed by the Commission to participate in the proceeding.

[11] BCUC Utility System Extension Test Guidelines, p.1.

[12] BCUC Utility System Extension Test Guidelines, p.1.

[13] Commission Decision and Order G-80-96 is the Phase II Reconsideration Decision for the Generic Review of Utility System Extension Tests that superseded the initial Utility System Extension Test Decision Order G-19-96 issued on February 16, 1996. The Commission's authority to issue directions on a utility's generic system extension test in the manner that it did in Order G-19-96 was challenged by several interveners. This resulted in the Phase II Reconsideration Decision that converted the direction of Order G-19-96 into a set of voluntary guidelines.

[14] BCUC Utility System Extension Test Guidelines, p. 31-33.

1. The Commission recommends that evaluation of system extensions be based on a DCF evaluation method that includes, to the extent feasible, all incremental costs and benefits associated with a particular system extension over a time period long enough to consider the full impact of the extension. The Commission also recommends that, as a general principle, the costs of system extensions be allocated to those customers who cause them.

2. The Commission recommends that the Utilities evaluate system extensions both from a social perspective, which applies a social discount rate, and a utility perspective, which applies a discount rate based on each utility's cost of capital.

3. The Commission recommends that Utilities submit extension tests or information that analyzes system extensions on a disaggregated basis. However, where the benefits of aggregation exceed the costs as may be the case for situations involving routine, short extensions, the Commission will consider Utility proposals for dealing with such situations. The Commission recommends that these proposals be based on the incremental cost of extending the system and adding new customers. For the purposes of annual statement filing, the Utilities initially may choose the level of aggregation they deem appropriate. The extent of aggregation will depend on the projects planned by each utility in a given year.

4. The Commission expects the Utilities to ensure that estimates are as accurate as possible without adding substantially to the administrative workload associated with estimating system extension costs. The Commission will rely on prudency reviews to examine the accuracy of system extension estimates.

5. The Commission recommends that the costs and benefits to be considered in the analysis of proposed system extensions include pre-construction estimates of the following:

   a) construction costs of the system extension;

   b) associated incremental system improvement costs, where these can be identified and assessed in a cost-effective manner;

   c) associated incremental operation and maintenance costs, where these can be identified and assessed in a cost-effective manner;

   d) net costs of connection (i.e., cost of connection less connection fees);

   e) net revenues from the system extension (i.e., customer payments less revenues to provide for commodity purchases and upstream transmission charges); and

   f) a reasonable consideration of externalities (for the social perspective evaluation).

6. The Commission recommends that Utility connection charges move toward recovery of the full costs of the service connection up to but not including the meter, and include incremental costs such as applicable system improvement costs. In addition, the

Commission recommends that the Utilities come forward with options for connection fees that send an appropriate signal about the net social costs of less efficient energy use.

7. Until such time as the connection charge recovers all connection costs, the Commission recommends that the Utilities include the cost of the service connection and any revenues to be received from connection charges in their system extension test.

8. In cases where a customer contribution is required, the Commission anticipates that the cost would be borne by those customers benefiting from the system extension. In situations where the consideration of social costs may lead to contributions by other customers, the Commission will want to review the matter.

9. Alternative methods for collecting customer contributions are discussed in section 6.5 [of that Decision]. In the Commission's view, viable mechanisms would satisfy the following criteria:

    a) introduce additional options for financing system extensions, thereby reducing the financing pressures on local government (i.e., the use of local taxation mechanisms);

    b) reduce the incentive for prospective customers to avoid the contribution charge by not applying for connection until after the system extension has been funded and constructed; thus the Commission recommends that, at a minimum, all customers who attach within the first five years to contribute to system extensions;

    c) ensure that those customers paying an initial contribution are reimbursed as additional customers connect, at least for a reasonable initial period; and

    d) minimize risk to the utility and its ratepayers while avoiding undue administrative burden, perhaps by including mechanisms such as deferral accounts or 'dead-bands' within which no refund would be required.

10. If a community application for a system extension is close to break-even with respect to the financial cost test, the utility may be required to justify the extension with a preliminary comparative analysis of all feasible alternatives for meeting the community's energy service needs. This analysis would include recognition of significant social or environmental impacts associated with each alternative. The utility can either file this information voluntarily with its annual statement or expect to file it as part of a CPCN application, should a CPCN be required for the project.

Order G-80-96 and the accompanying decision and the Guidelines reaffirmed the DCF method as the appropriate approach to evaluate the economic viability of proposed main extensions.

Today, the DCF approach continues to serve as the methodology used to determine the economic viability of main extensions for FEI.

2.1.3 1996 Rate Design Application and the Service Line Cost Allowance and Commission Decision & Order G-104-96

In 1996, the Company filed a rate design application (the 1996 Rate Design Application), in which the Company sought approval of a SLCA to serve new residential and small commercial customers connecting to existing mains (referred to as 'infill' customers). While the MX Test can be used to determine if any contribution is required from customers wishing to connect to *new* mains, the SLCA was intended to determine if any contribution is required from infill customers wishing to connect services from *existing* mains (i.e. where only a service line is required), where the application of a comprehensive MX Test is administratively impractical. The proposed SLCA effectively limited the amount the Company would contribute to a service line connection. Any cost requirement for a service line connection that exceeded the proposed allowance would require a contribution from the customer wishing to connect. The proposal provided greater flexibility for residential and small commercial customers to choose a service route other than the most cost effective one while ensuring that costs were adequately and fairly recovered by the Company.

The SLCA was proposed to replace a number of then existing customer connection charges for infill customers that were not reflective of the actual cost to connect. Based on cost data in 1996, the Company proposed an SLCA of $1,100 per service line connection along with an $85 application fee to be applicable to infill customers.

In the Decision accompanying Order G-104-96, the Commission approved the $1,100 SLCA and a service line installation fee (SLIF) of $215, in addition to the proposed application fee of $85, applicable to infill customers. A new customer wanting to connect to an existing main was now required to pay a standard fee of $300, in addition to any costs incurred that exceeded the $1,100 SLCA threshold.

2.1.4 BC Gas 1996 Application to Revise its System Extension Test & Commission Letter L-46-96

In response to Commission Order G-80-96 regarding the Generic Review of Utility System Extension Tests, the Company filed its revised System Extension Test Submission on August 30, 1996, which was filed concurrently with the 1996 Rate Design Application. The Company proposed to continue the use of its MX Test as approved by Commission Order G-101-93, but modified the Test in response to the Phase II Reconsideration Decision. Main proposed changes to the Test included:

- A reduction to the revenue forecast time frame for the MX Test to match the IRP planning time frame of 20 years, in order to align more explicitly with the Company's IRP criteria as required by BCUC Order G-101-93. Note that the reduction to 20 years was proposed as a trade-off in order to reach a decision. This was a reduction from the 33 year revenue forecast time frame that was used and that aligned with the depreciation life of meters, which was already significantly less than the life of a main.
- The use of the SLCA amount in the MX Test to cap the cost of expected service lines.

- The incorporation of the associated application fees (the SLIF and application fee) in the calculation of the expected cost and revenues for a main extension.

By Letter L-46-96 issued November 5, 1996, the Commission found the Company's proposal to be in accordance with the Guidelines. The Commission recognized in the Letter that "BC Gas has put significant effort into developing a valid and useful system extension test"[15]. The revised policy, reflected in the Company's tariff, took effect January 1, 1997.

2.1.5 2007 System Extension and Customer Connection Policy Review Application and Decision & Order G-152-07

During the Company's 2006 Annual Review and Mid-Term Review Workshop conducted in accordance with the 2004-2007 Performance Based Rate Settlement, the Company committed to conduct a comprehensive review of its system extension and customer connection policies, including the MX Test. By Order G-160-06 the Commission directed the Company to file a review of its system extension tests by the end of the second quarter of 2007, for implementation in 2008[16].

The Company[17] subsequently filed its System Extension and Customer Connection Policies Review application (the 2007 Application). In the 2007 Application, the Company proposed a number of changes to its system extension and customer connection policies in consideration of the regulatory environment and market conditions the Company faced at the time. The Company noted that the market place was shifting away from the use of natural gas as a result of commodity price and governmental policy regarding $C0_2$ emissions. For instance, natural gas faced competitive pressures from electricity both in terms of the commodity price and the upfront capital cost to install natural gas heat and hot water systems (compared to electric baseboards and water heaters)[18]. The proposed changes were intended to remove barriers for new customers to connect to the distribution system. More specifically, the objectives were:[19]

- To signal better value for customers wishing to attach to the system;
- To ensure that the system extension test and policies measure the right factors, be simple to understand and administer with results that send the appropriate economic signal to the customer;
- To encourage energy conservation through the test and attachment policies (the Company had only a very small DSM program at the time); and
- To encourage the "right fuel" choice, in support of the Company's belief that natural gas is an appropriate fuel for space and water heating applications and that the connection

15 L-46-96, p.2.
16 G-160-06, Appendix A, p.11.
17 Representing FEI and FEVI at the time.
18 2007 Application, at page 8-9.
19 2007 Application, at page 4.

policies and tests should send the appropriate signal to customers for these energy uses.

The Company's proposals in the 2007 Application are further explained below.

2.1.5.1 The Elimination of the Service Line Installation Fee and the Increase of the Service Line Cost Allowance

In the 2007 Application, the Company demonstrated that the addition of the SLIF resulted in an over-contribution from new customers and served as a cost barrier to customer connections. The Company noted that all costs associated with connecting new customers, both infill customers and those customers requiring a main extension, were factored into the calculation of the SLCA, application fee and the MX Test where applicable, and that new customers were fully contributing to the cost of service through these mechanisms. The Company thus requested the elimination of the SLIF of $215.

The Company also proposed to increase the SLCA for single family dwellings and duplexes based on updated consumption and cost data at the time.

By Order G-152-07, the Commission approved the elimination of the SLIF, and authorized the Company to increase the SLCA for single family dwellings and duplexes to $1,535 and $3,070[20] respectively.

2.1.5.2 The Introduction of Consumption Credits to Account for the Benefits of Energy Efficiency Measures

At the time of the 2007 Application, the Company only had a small demand side management (DSM) program. As such, the Company believed it would be appropriate to encourage additional DSM initiatives on the part of customers through the use of an appropriate mechanism in the MX Test. By recognizing the benefits of DSM activities in the MX Test, it would send the correct market signal.

The Company thus introduced additional credits for customers who made energy efficiency choices. For instance, the SLCA and the MX Test applicable at the time made no distinction between high efficiency appliances and standard efficiency appliances. Perversely, if consumption volumes were adjusted to reflect the use of high efficiency appliances instead of the average value, the MX Test would result in a less profitable extension and/or the SLCA would be lower. That is, a new customer using more energy efficient appliances that required a main extension could potentially be at risk of failing an MX Test and be required to pay a CIAC based on the lower expected consumption, when the customer could have passed the test had they used less energy efficient appliances. For infill customers, the implications were similar in that they could be required to make a higher contribution as a result of their decision to use

[20] The SLCA for duplexes was set at double the amount of the SLCA for single family dwellings.

more energy efficient appliances in the event the SLCA did not fully cover the cost for the service line.

To address this paradoxical situation, the Company proposed to apply a consumption credit for customers using high efficiency appliances that would adjust their average consumption within both the MX Test and the SLCA calculations to account for the benefits of energy conservation. Specifically, the Company proposed to apply the following consumption credits for use in the MX Test over and above the average consumption per appliance:

- For customers with standard efficiency gas-fired space and water heating: Consumption Credit of +5% of the volume otherwise used for both appliances;
- For customers with high efficiency gas-fired space heating (namely an Energy Star rated furnace or boiler) and water heating (tank-less water heaters or water heaters with an efficiency rating of +78%): Consumption Credit of +10% of the volume otherwise used for both appliances; and
- For customers who have both high efficiency gas-fired space and water heating appliances as defined above, and who attain a minimum of LEED™ General Certification: Consumption Credit of +15% of the volume otherwise used for both appliances.

The Company similarly proposed to apply these consumption credits to increase the consumption value used to derive the SLCA amount, which would have increased the SLCA amounts to account for the benefit of energy efficiency measures.

By Order G-152-07, the Commission approved the +10% and +15% consumption credits for high-efficiency and LEED™ certified appliances for use in the MX Test, but denied the +5% credit for standard efficiency appliances because they made no contributions to energy efficiency[21]. The Commission also did not approve the Company's proposal to apply the proposed consumption credits to increase the consumption value used to derive the SLCA amounts. The Commission encouraged the Company to apply for the approval of a DSM program. In the Commission's view, the proposed increase to the SLCA allowance was more in the nature of DSM programs since the SLCA was based on average residential consumption that reflected the end use of all gas appliances including those used for non-space and water heating purposes[22].

In sum, Order G-152-07 approved the use of energy efficiency credits over and above the average consumption per appliance where warranted in the MX Test.

[21] Commission Order G-156-07, p. 51.
[22] Ibid.

2.1.5.3 The Establishment of Individual and Aggregate PI Thresholds and Other Changes to the MX Test

As part of the 2007 Application, the Company also sought approval for the following components of the MX Test:

- To continue using the DCF-based MX Test;
- To use distribution related costs to determine the System Improvement (SI) charge for the Vancouver Island utility to be consistent with the Mainland utility;
- To use an aggregate Profitability Index (PI) threshold in addition to the individual main extension PI threshold. The Company proposed to use a PI of 0.8 as the lower economic threshold for passing individual main extensions, and an aggregate PI of 1.1 as the threshold for all main extensions completed on an annual basis. This was a change from the single PI threshold of 1.0 for all main extensions; and
- To discontinue the use of the SLCA in the calculation of expected costs for new main extensions since a distinction between the service line and main was not made and the cost required to provide service was an input in the MX test.

By Order G-152-07, the Commission accepted the continued use of the DCF-based MX Test, as well as the proposed change to the calculation method of the SI Charge. The Commission also found that the Company's proposal to establish an aggregate and individual PI threshold and to exclude the SLCA as an input for the MX Test was in the public interest and compliant with the Guidelines.

2.1.5.4 Administration & the Main Extension Report

Order G-152-07 directed the Company as follows as it relates to administration and main extension reporting:

> *"So far as concerns the ongoing administration of the Companies main extension and service line policies the Commission Panel directs Terasen to update all Geo-codes and MX test input parameters at the beginning of each year. To determine the appropriate Geo-code for each area, both historical costs and a forecast of future costs will be used. Terasen is to provide the Commission with schedules comparing the existing and updated Geo-codes and MX test input parameters. Given that the 2002 REUS does not include TGVI data, the REUS use per appliance should not be used to estimate TGVI consumption, and the Commission Panel directs Terasen i) to update the consumption estimates in the TGVI MX test to reflect TGVI use per appliance; and ii) to reflect in the Companies' MX tests their experience of consumption "ramp-up" in the early months of service.*
>
> *The Commission Panel directs the Companies to file with Commission on an annual basis, within 90 days of calendar year end, a Main Extension Report including the following:*

- *A review of a random sampling of MX test results representing a confidence interval of +/- 12 percent at a 95 percent confidence level and the five highest cost main extensions to determine if the aggregate PI thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1. The review is to include a comparison of forecast and actual costs; consumption; and PI for the first five years of main extensions in the sample;*
- *A concise explanation of the random sampling methodology used; and*
- *A comparison of the forecast and actual cost for all service line and main extension installations."*[23]

The directives above specify the Commission's compliance criteria for the ongoing administration of the annual MX Report.

2.1.5.5 Vertical Subdivisions and BCUC Order G-06-08

In November 2007, the Company applied for approval to provide service to vertical subdivision developments, which was approved by Order G-06-08. In approving that application, the Commission directed the Company to:

- Include in its MX Report the result of the Company's main extension tests for vertical subdivisions; and
- Ensure that the MX Test inputs for vertical subdivisions reflect the fact that larger developments may require several years before all units are occupied and normal consumption patterns are established (often referred to as consumption "ramp up").

2.2 CURRENT SYSTEM EXTENSION CONSTRUCTS

The design and input parameters of the MX Test have remained largely unchanged since Commission Order G-06-08, with the exception of the application fee, which was reduced from $85 to $25 to reflect the updated cost of providing the service, approved through Order G-141-09 in the Company's 2010-2011 Revenue Requirement proceeding.

The following section provides an overview of the components of the MX Test, the SLCA and CIAC that have been in place since 2007 as approved by Commission Orders G-152-07 and G-06-08 and as currently reflected in FEI's General Terms and Conditions.

2.2.1 MX Test

The MX Test assesses whether the main extension is economic, or in other words, it establishes the appropriate level of investment the Company will make on behalf of a customer wishing to attach to the Company's distribution system. This serves to ensure that the interests of existing and new customers are balanced.

[23] Order G-152-07 page 36-37

Currently, all applications for main extensions, service connections for large commercial Rate Schedule 3 customers, and connection to a service header, including vertical subdivisions, are subject to the Commission approved MX Test.

The MX Test is a DCF analysis that considers the revenues and costs associated with a planned main extension over a 20 year period. The Test produces a PI for a particular main extension, shown as the ratio of:

1. The discounted present value of the estimated net cash inflows over twenty years; and
2. The discounted present value of the capital costs of attaching customers in the first five years of the main extension.

The net present value (NPV) calculation is derived using a discount rate based on FEI's weighted average cost of capital (inflation adjusted and after tax).

If the results of the Test do not meet the approved PI threshold, a financial contribution is required from a customer. Specifically, if an individual PI is 0.8 or greater, a system extension can proceed without the need for a customer contribution. If the PI is less than 0.8, a customer contribution is required to bring the PI up to the 0.8 threshold in order for the system extension to proceed. In aggregate, the portfolio of main extensions completed on an annual basis is to have a PI of 1.1.

Figure 2-1 below illustrates the current MX Test formula and its major components.

Figure 2-1: Current MX Test Formula

Net Present Value of Net Cash Inflows (20 Year DCF Term)

(Delivery Margin + Application Fees-O&M-System Improvement –Municipal Tax-Property Tax-Income Tax)

P.I. =

(Mains, Services & Meter Costs + Overhead + Working Capital)

Net Present Value of Capital Costs (5 years of Attachments)

Each of the components of the NPV of cash inflows and NPV of Capital Costs is described in detail below.

2.2.1.1 NPV of Net Cash Inflows

As indicated in Figure 2-1, the following components are factored into the calculation of the NPV of cash inflows:

- Delivery Margin;
- System Improvement Charge;
- Application Fee;

- O&M; and
- Municipal, Property and Income Tax.

Each of the above components is further described below.

2.2.1.1.1 DELIVERY MARGIN

The delivery margin is calculated as follows:

Delivery Margin = ((FEI Basic Charge x Number of Customers) + (FEI Delivery Charge x Number of Customers x Consumption per Customer)).

FEI Basic and Delivery Charge

The basic and delivery charges are updated annually as of January 1 based on FEI's rates at the time, and the appropriate rate is then applied in the Test.

Number of Customers

Many components of the MX Test apply the number of customers forecast to connect to a particular main extension over five years. The number of customers for a proposed main extension is estimated through discussions between the customer and FEI. For example, a hypothetical main extension may have a 5 year customer forecast as follows:

Year 1	= 10 customers
Year 2	= 2 customers
Years 3 to 5	= no additional customers
Total	= 12 customers over years 1-5

In this example, for the purposes of the 20 year DCF MX Test, the number of customers for years 3 to 20 is assumed to be constant at 12 customers per year. That is, no new customers are assumed to connect to the main after year 3. This assumption provides for a conservative input for customer additions used in the MX Test.

The fact that the DCF analysis assumes no customer additions after an initial five year period makes it an appropriate conservative basis for an *ex ante* test for main extensions. However, that same feature makes re-running the MX Test each year for past main extensions with updated forecasts inappropriate for determining *ex post* whether those extensions have been economic. An extension will continue to generate benefits for its service life (in excess of 50 years), and customers will continue to join the system after the fifth year. This is one of the key objections that FEI has to the Commission's current practice of asking FEI to re-run the MX Test for the purpose of evaluating whether or not past extensions have been beneficial to customers. This is addressed later in sections 3 to 5.

Consumption per customer

The consumption per customer reflects a credit each new customer receives for gas consumed by the appliance(s) being installed in his/her home. It is derived by multiplying the individual appliances to be installed by the average consumption per appliance.[24] The individual appliances to be used by the customer are determined through conversations between FEI and its customers. The average consumption per appliance is based on the consumption of existing customers. The values are drawn from the Company's Residential End Use Study (REUS), which is produced every four years. The Company is currently using data from the most recent 2012 REUS in its MX Test.

In the 5 year customer forecast example provided above, if FEI determined that a builder/developer customer intended to install a furnace in each of the 12 homes being built, the consumption credit would be derived as follows:

12 homes x 1 furnace/home x 52.4 GJ / furnace = 628.8 GJ.

In this example, 52.4 GJ is the average consumption per furnace value found in the 2012 REUS. Additional appliances such domestic hot water, fireplaces and cook tops are estimated in a similar fashion. The aggregate consumption of all appliances is used in the MX Test.

For commercial and industrial customers, consumption is determined based on the specific business needs and/or operational requirements of each customer.

Two other considerations are factored in when determining the consumption per customer.

First, as discussed in Section 2.5.1.2 above, the Company may encourage the installation of energy efficient appliances by providing the customer with an incentive in the form of additional consumption credits in the MX Test.

Second, in accordance with Commission Order G-06-08, a ramp up factor is included in the consumption per customer calculation to account for the fact that new customers will connect to the system sometime during the first year and therefore will not achieve a full year's worth of consumption for that year. The ramp-up factor is set at 80% for all main extensions. For example, a home with a consumption credit of 100 GJ will receive a consumption credit of 80 GJ for the first year in the MX Test (i.e. 80% is a proxy for a full year of consumption).

FEI provides a reasonable estimate of the consumption per customer based on customer input, the most current REUS data on existing customers and, more generally, methodologies approved by the Commission.

[24] Prior to the Residential End Use Study of 2004, the Company simply used the total average of the residential customer class in determining revenue. In other words, each new residential customer was credited with 110 GJ consumption. This changed after the REUS as better information was available on individual appliances.

2.2.1.1.2 APPLICATION FEES

A $25 application fee per customer was approved by Order G-141-09. The application fee input for the MX Test is derived by multiplying the $25 per customer by the number of customers.

2.2.1.1.3 OPERATIONS AND MAINTENANCE (O&M)

The O&M input to the Test is intended to capture the incremental O&M required to connect a new customer to the Company's distribution system, derived by multiplying the O&M per customer by the number of customers. O&M is updated on an annual basis.

2.2.1.1.4 SYSTEM IMPROVEMENT (SI)

The SI charge is a per gigajoule charge and is a proxy for the incremental system improvement costs associated with growth that are not attributable to a specific customer. At a high level, the SI formula is as follows:

SI = Number of Customers x Consumption per Customer x SI Charge per GJ

As requested in Commission Letter L-67-11, the Company updates the SI charge on an annual basis using a methodology developed together with Commission staff.

2.2.1.1.5 MUNICIPAL TAX

The municipal tax input is derived by taking the sum of the delivery margin for all customers multiplied by an in lieu rate of municipal taxes. An in lieu value is updated annually.

2.2.1.1.6 PROPERTY TAX

Property tax is calculated by multiplying the cost for mains and services by FEI's property tax rate. FEI's property tax rate is updated annually.

2.2.1.1.7 INCOME TAX

Income tax is calculated as follows:

Income Tax = (Income after Municipal Taxes – Capital Cost Allowance) x Income Tax Rate

where,

Income after Municipal Taxes = Delivery Margin + Connect Fees – O&M – SI – Municipal Tax – Property Tax

and,

Capital Cost Allowance = (mains, service lines and meters costs + overhead) x Capital Cost Allowance Rate

The Capital Cost Allowance (CCA) uses rate Class 51. It is updated annually along with FEI's income tax rate (Federal & BC Provincial) as determined by the Canada Revenue Agency.

2.2.1.2 NPV of Cash Outflows

The NPV of cash outflows calculation is as follows:

NPV of Cash Outflows = Mains, Services & Meter Costs + Overhead + Working Capital.

The components of the NPV of cash outflows are further described below.

2.2.1.2.1 MAIN, SERVICES AND METER COSTS

The estimated cost to install mains, services and meters is dependent on the individual circumstances of the customer. Factors such as the number of dwellings or businesses, the distance of the main extension required and any potential encumbrances impact the cost estimate.

The Company uses a combination of a Geographic Code pricing model (geo pricing) and manual estimates to derive cost estimates. Geo pricing represents an average cost per metre in a particular region, typically used for simpler projects. Manual pricing or estimating refers to a more manually intensive estimate derived by FEI's planning department in conversation with the customer.

2.2.1.2.2 OVERHEAD

Overhead is a proxy for the incremental overhead that is allocated to an individual project. Overhead is calculated by multiplying mains, services and meter costs by the overhead rate.

The overhead rate is updated annually.

2.2.1.2.3 WORKING CAPITAL

Working capital is calculated as follows:

Working Capital = (Mains, Services & Meter Costs + Overhead) x Working Capital Rate.

The working capital rate is updated annually.

2.2.1.3 MX Test Summary

The Company has been using reasonable, Commission approved methodologies to develop the various estimates used in the MX Test. Every year in its MX Report, the Company provides the Commission with the actual input values used in the MX Test. For example, the 2014 MX Report, included as Appendix D-1, contains all the relevant data used for all the MX Tests completed in 2014[25]. The MX Report also includes additional compliance data including a comparison of the forecast and actual cost for all service line and main extension installations.

2.2.2 Service Line Cost Allowance (SLCA)

The SLCA represents the maximum allowance each infill customer receives when connecting to an existing main. A single family residential dwelling or small commercial customer[26] is currently allocated a SLCA of $1,535 ($3,070 for a duplex).

The derivation of the current SLCA values is detailed in Section 4.2

2.2.3 Contribution in Aid of Construction (CIAC)

As approved by Order G-152-07 and reflected in section 12 of FEI's General Terms and Conditions, if the MX Test results indicate a PI of less than 0.8, the main extension may proceed provided that the shortfall in revenue is eliminated by the CIAC paid by the customers to be served by the main extension.

The total required CIAC will be paid by the customers connecting at the time a main extension is being built, and FEI will collect contributions from all customers connecting during the first five years after the main extension is built. As additional contributions are received by customers connecting to the main extension, partial refunds are made to those customers who had previously made a contribution. At the end of the fifth year, all customers will have paid an equal contribution, after reconciliation and refunds. In instances where refunds are granted to customers who have contributed, the main is referred to as a "contributory main."

The CIAC is an upfront cost to be borne in full by the customer at the time of the construction of the main extension.

2.3 SUMMARY OF BACKGROUND

The Company's system extension policies and related constructs have been defined through a number of regulatory proceedings before the Commission dating back to 1993. Since that time, the purposes and design of the MX Test, SLCA and CIAC have remained consistent, with periodic updates approved by the Commission. In the MX Test, FEI uses reasonable estimates based on customer input, the most current data available to the Company and, more generally, methodologies approved by the Commission.

As further discussed in the following section, the design of the MX Test, SLCA and CIAC approved by the Commission remains appropriate in assessing whether main extensions should proceed without a contribution from the new customers. However, updates are required to reflect the passing of time since the last time the Company's system extension policies were reviewed in 2007.

[25] FEI Main Extension Report for 2014 Year End. Submitted March 30, 2015, pp. 17-20.
[26] Referred to as "Other than a duplex" in FEI's Standard Fees and Charge Schedule.

In terms of reporting, the Commission identified as a purpose of the reporting as being "to determine if the aggregate PI thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1." Ensuring that the MX Test is doing what it was intended to do is a reasonable objective. However, some of the annual processes since 2007 have taken on more of a character of hindsight assessments of whether FEI ought to have undertaken particular extension(s). As explained later in this Filing, the evaluation methodology used by the Commission is not fit for the purpose of assessing FEI's prudence, and there are better ways to assess whether or not the MX Test parameters continue to meet the initial goals of the Test.

3. SYSTEM EXTENSION POLICY REVIEW

In 2013, the Company initiated a review of its customer connection and MX Test in the context of preparing and filing its annual MX Report for 2012 (the 2012 MX Report).[27] The Company believed there was a need to consider possible changes to its policies to reflect the passing of time. Specifically, there were three main reasons for the review:

1. Customers wanted FEI to examine potential barriers to accessing natural gas service;
2. The Company had identified several potential enhancements to its current system extension policies; and
3. There were opportunities to improve MX reporting and evaluation practices.

Thus, in the 2012 MX Report, the Company proposed to:

> *"… review the results of the [2012 MX] Report and begin to identify Stakeholders and a process to review the System Extension policies; and engagement of applicable Stakeholders, Staff and the Company will follow. This engagement will include educational workshops to review the relevant issues and develop a go forward plan."*[28]

The Company has since completed the review. The process has yielded a number of recommendations found in Section 4, developed through stakeholder consultation and expert analysis.

In this section, the Company first describes the review process followed, including its consultation with an expert and the consultative stakeholder process led by the Company. It then describes the high level outcomes of the review process. The review undertaken demonstrated that the Company's current MX Test and SLCA remain broadly applicable; however, there are opportunities to make improvements to the MX Test, the SLCA, the Company's current practices with respect to providing alternative methods of recovering CIAC from customers and the MX reporting and evaluation practices.

3.1 *REVIEW IN CONJUNCTION WITH EXPERT*

In 2013, the Company engaged EES Consulting Ltd.[29] (EES or EES Consulting) to conduct a preliminary survey of the Company's policies compared to those in other jurisdictions. EES Consulting is an energy consulting firm with expertise in the design of rate mechanisms such as extension tests. The relevant curricula vitae for EES Consulting are included in Appendix A.

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[27] FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. 2012 FEI-FEVI Main Extension Report filed March 31, 2013.

[28] Ibid, at pages 8-9.

[29] EES Consulting Ltd. is a multidisciplinary management consulting firm with particular expertise in rate design methodology, cost of service modelling and system extension policy. The curricula vitae of the authors of the reports are included in Appendix A.

A report containing the initial results of this survey, referred to as the 2013 EES Report, was included as an appendix to the 2012 MX Report filed with the Commission, and was suggested to the Commission as a starting point for the review of the Company's system extension policies.

EES completed additional analysis in 2015 (the 2015 EES Report), which built on the preliminary findings from 2013. A copy of the 2015 EES Report is included in Appendix A to this Application.

Part of EES Consulting's retainer was to participate in the stakeholder consultation process described next, to offer input and answer questions.

3.2 *CONSULTATION PROCESS*

In order to have an effective review of the Company's system connection policies, FEI also initiated a consultation process that involved a wide range of participants. FEI met individually with prospective stakeholders in late 2013 and obtained support for conducting a consultative review of its system extension policies starting in early 2014. FEI obtained input on the design of the consultation process, as well as the substance of the system connection policies. The key consultation materials have been appended to this filing.

3.2.1 Participants

Stakeholders came from varied backgrounds including Commission staff and experienced intervener groups and others that were less familiar with the regulatory process. Experienced participants included British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO), B.C. Sustainable Energy Association and Sierra Club of British Columbia (BCSEA), Commercial Energy Consumers Association of British Columbia (CEC), B.C. Hydro and Power Authority (BC Hydro), Pacific Northern Gas (PNG) and FortisBC Inc. Additionally, FEI invited parties who would be directly affected by system extension changes but did not traditionally intervene in regulatory proceedings, including a number of First Nations groups, regional district representatives and municipal and provincial politicians. Two provincial government ministries also participated. The table below contains a list of stakeholders who attended the various workshops:

Table 3-1: Participants in FEI's System Extension Review

Stakeholder	Attendee	Title
BC Hydro	**Justin Miedema**	Senior Regulatory Advisor, Rates and Regulatory
	Kevin Lim-Kong	Policy Specialist, Customer Interconnections & Policy
	Frank Lin	Director, Interconnections and Shared Assets
	Rena Messerschmidt	Policy Manager, Customers Interconnections & Policy

Stakeholder	Attendee	Title
BC Ministry of Energy and Mines	**Katherine Muncaster**	Acting Director, Energy Efficiency Branch
BC Ministry of Jobs, Tourism and Skills Training	**Robert Wood**	Acting Director, Major Investments Office
BC Public Interest Advocacy Centre	**Tannis Braithwaite**	Executive Director
B.C. Sustainable Energy Association & Sierra Club B.C.	**William J. Andrews**	William J. Andrews, Barrister & Solicitor
	Thomas Hackney	Case Manager
BCUC Staff	**J Todd Smith**	Acting Director, Infrastructure
	Suzanne Sue	Senior Regulatory Specialist
	Chris Garand	Engineer, Infrastructure
Chawathil First Nation	**Norman Florence**	Council Member
	Bobbi Ellen Peters	Council Member
Commercial Energy Consumers	**David Craig**	President, Consolidated Management Consultants
EES Consulting	**Gail Tabone**	Senior Consultant, EES Consulting
Fortis BC	**Mike Metza**	Energy Products & Services Manager
	Brent Graham	Manager, Energy Products & Services
	Jason Wolfe	Director, Market Development
	Dennis Swanson	Director, Regulatory Affairs
	Corey Sinclair	Manager Regulatory Affairs
	Vanessa Connolly	Government Relations and Public Affairs Manager
	John Turner	Director, Energy Solutions
Fraser Valley Regional District	**Lloyd Foreman**	Director, Electoral Area A
	Dennis Adamson	Director, Electoral Area B
MLA Boundary - Similkameen	**Colleen Misner**	Constituency Assistant to Linda Larson, MLA
MLA Kootenay West	**Katrine Conroy**	MLA
Okanagan - Similkameen Regional District	**George Bush**	Board Member
Peace River Regional District	**Karen Goodings**	Board Director
Pacific Northern Gas	**Janet Kennedy**	Vice President, Regulatory Affairs and Gas Supply
	Peter Schriber	Manager, Financial Planning & Business Development
Seabird Island Band	**Brian Titus**	Consultant
	Chief Clem Seymour	Chief
Ucluelet Chamber of Commerce	**Susan Payne**	Executive Director, Ucluelet Chamber of Commerce
Yale First Nation	**Steven Patterson**	Natural Resource Manager

3.2.2 Consultation Approach

On February 18, 2014, FEI held the first workshop in the review, which focused on providing stakeholders with a general understanding of the Company's current system extension policies including the purpose and function of the MX Test, the SLCA and the CIACs in connecting new customers to the natural gas distribution system. Throughout the workshop, stakeholders spoke to a range of issues, such as the different types of new gas customers, their needs when making energy choices, provincial government energy objectives, as well as a discussion of the system extension policies of other utilities in Canada and the Pacific Northwest as provided by EES.

Stakeholders discussed that the process followed in 2011 to establish FEI's current Gas Supply Mitigation Incentive Program (GSMIP) was effective and could serve as a model to engage stakeholders and pursue a streamlined application to the Commission. In particular, the following components were seen to be valuable:

- Providing education to stakeholders on the issues as well as a venue to express their views so they could fully participate in the process;
- Using an expert in the field of inquiry to help provide education and analysis;
- Developing guiding principles which would be used to shape future recommendations; and
- Seeking to develop a preliminary view to support updates prior to filing an application with the Commission.

In light of these findings, stakeholders agreed to continue with the review in a manner resembling the GSMIP process.

Following the first workshop, the Company circulated a draft terms of reference (TOR) for comment from stakeholders. During the second workshop, the draft terms were discussed further, and a second draft was circulated for final review. The TOR is included in Appendix B-5.

The review provided a venue to educate stakeholders and solicit their feedback on the MX Test and related policies. Many of the stakeholders were new to the regulatory process so it was necessary to provide adequate background to ensure that all stakeholders could participate fully in the process.

Stakeholders were engaged and committed to the review. Many wrote letters to the Commission indicating support for the review process. For instance, the following observations from Linda Larsen, MLA Boundary Similkameen, illustrate her support for the review:

> *"…the need for natural gas in our communities is critical. We were thrilled to be asked [to participate in the Review] because we feel that it is an important issue that needs to be addressed, assessed and "fixed" as soon as possible to ensure that all British*

Columbians living in areas without access to alternative sources of power get that access. After two sessions, while we are still trying to understand all the technicalities, we feel that some headway is being made and are eager to continue to participate"[30]

The Commission staff indicated it supported the Company's efforts to consult stakeholders prior to an application and encouraged the Company to continue the consultation in a timely manner, as indicated in Letter L-44-14 included in Appendix C-12.

3.2.3 Overview of Workshops

The following table summarizes the stakeholder consultation the Company undertook. Each of the workshops[31] described below were full day sessions.

Table 3-2: Stakeholder Review Summary

Date	Item	Topic	Outcomes
Q4 2013	Individual Consultation	Initial Consultation	Garnered stakeholder support to begin review.
February 18, 2014	Workshop #1	Policy Issues	Discussed system extension issues and solicited stakeholders' support to proceed with review.
June 18, 2014	Workshop #2	Term of Reference	Secured stakeholder feedback on TOR of the review and continued dialogue on issues.
October 8, 2014	Workshop #3	Options Discussion	Reviewed system extension options as developed by FEI and stakeholders.
December 8, 2014	Workshop #4	Options Discussion	Integrated stakeholder feedback to support updates

3.2.4 Guiding Principles

One of the major outcomes of the review were the Guiding Principles developed in consultation with stakeholders by considering the following: the Commission's Guidelines, rate design concepts[32], and past Commission Orders including Orders G-152-07 and G-06-08. The following section describes each of the five Guiding Principles in more detail.

3.2.4.1 Provide an Energy Choice

A common interest among stakeholders was that the Company's system extension policies should promote energy choice in the Province. During the workshops, many stakeholders pointed out the potential benefits of using natural gas due to a relatively large drop in the price of natural gas in recent years compared to other energy sources. These benefits include lower

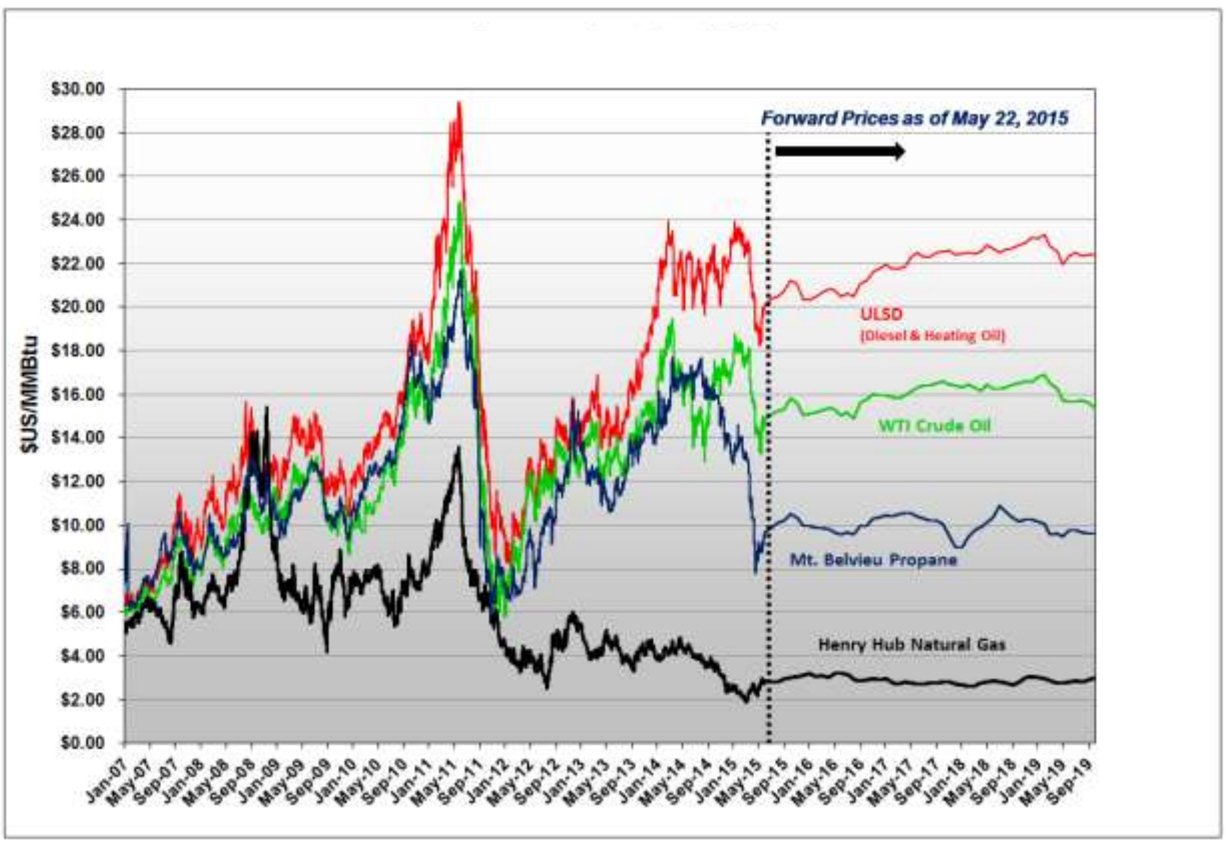
[30] Letter to Ms. Erica M. Hamilton, Commission Secretary, re: FortisBC Main Extension (MX) L-34-14 Registered Intervener Reply, July 15, 2014.
[31] Refer to Appendix B for related workshop material
[32] In particular, there was discussion of the Bonbright principles of rate design.

energy bills, local economic development, creation and retention of jobs, and tax and royalty revenue. This Guiding Principle is thus intended to enable new customers to more easily access natural gas should they choose to do so.

There have been significant changes in the natural gas marketplace since 2007 when the Company last submitted a system extension application to the Commission. Natural gas prices have decreased and the supply reserves in the Western Canadian Sedimentary Basin have increased. In contrast, back in 1996 and also in 2007, the outlook was for a decline of domestic natural gas supply. Evidence of the changes in the relative operating cost advantage of natural gas compared to other energy sources used in the Province is summarized below.

As Figure 3-1 below shows, in comparison to natural gas, the price of heating oil and propane has been higher since 2007 and the price differential is forecast to continue into the future. This means that customers with access to natural gas service would pay less on their utility bills than if they were using heating oil or propane. This also means that the absence of natural gas in less densely populated areas may result in higher utility bills from the use of heating oil or propane as a source of energy for heat and hot water.

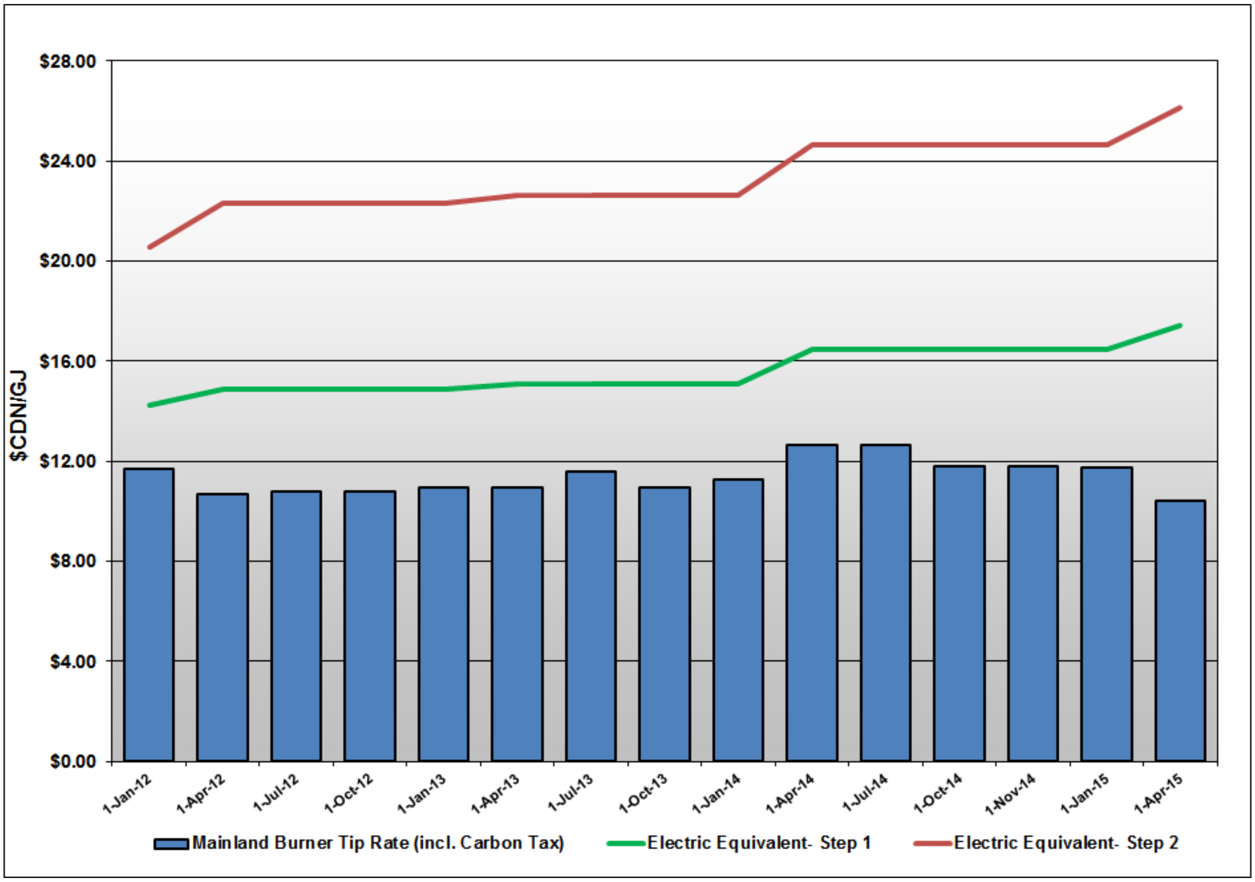
Figure 3-1: Competing Fuel Prices 2007-Present



As seen above, the wider the gap between the price of natural gas (shown in the black line) and that of propane and heating oil (blue and green lines respectively), the greater the operating cost advantage of natural gas.

Natural gas is also expected to remain competitive compared to electricity on an operating cost basis.[33] As shown in Figure 3-2 below, FEI's burner tip rate (absent upfront costs for appliances or a potential CIAC) has been below the Steps 1 and 2 electric equivalents since 2012[34]. The inclusion of higher upfront capital costs reduces the cost competitiveness relative to electricity, but it still remains.

Figure 3-2: BC Hydro Electricity vs. FEI Mainland Burner Tip Rates



Thus, for a typical residential customer, this means it is less costly to heat a home using natural gas than using electricity in the BC Hydro service territory. The conclusion is the same when comparing domestic hot water heating using natural gas with using electricity.

[33] https://news.gov.bc.ca/stories/10-year-plan-means-predictable-rates-as-bc-hydro-invests-in-system.

[34] FEI burner tip rate presented in the figure includes the commodity charge, storage and transport charge, fixed basic and delivery charges, and the carbon tax to provide a comparison against the electric equivalent. The Step 1 and Step 2 electric equivalents have been adjusted using a 75% efficiency to represent the average efficiency level of all existing space heating customers. It is important to note that the rate the BC Hydro customers ultimately pay is dependent on their actual consumptions (Step 1 and Step 2). This can impact the rate comparisons of natural gas against electricity depending on the customer's consumption levels for electricity. For example, water heating load may be better compared to Step 1 electricity rates because it generally has a flat yearly profile versus space heating which would have a winter profile (Step 2).

Due to the price differentials discussed above, from an economic perspective, having natural gas as an energy choice is beneficial. More specifically, FEI's summarizes the need for providing energy choice as follows:

- Customers want access to natural gas to save money on their total utility bills since heat and hot water are the biggest energy requirements in homes, and natural gas is less expensive to operate compared to heating oil, propane and electricity.
- Communities would support residents and businesses having more disposable income to invest in the regional economy rather spending it on utility bills.
- The provincial government could garner greater tax and royalty revenue from the increased domestic use of natural gas.
- Some municipalities could generate additional revenue from operating fees charged to customers who utilize natural gas in their communities.

In the workshops, stakeholders described the challenges and opportunities they faced in having greater energy choice, some using terms such as generational inequities while others simply expressing that "I just want it to be easier to get gas in my community." Some of the observations are summarized below:

- One First Nations stakeholder described his concern that many people in his community had difficulty affording their electric bills in wintertime due to the high price of electricity to heat a home.
- One of the stakeholders from the Okanagan succinctly described the problem in her area as people of a lower socio economic status having to choose to "heat or eat".
- A possible generational inequity in the current system extension policy was discussed by stakeholders based on the understanding that the interests of new natural gas customers were being overshadowed by those of existing customers. Many stakeholders described how existing customers have access to the benefits of low cost natural gas whereas many prospective customers face a barrier, such as the CIAC.
- There may also be regional inequities because it is generally easier for a customer in an urban area of the province to access natural gas compared to a person living in a rural area or a community currently not served by FEI or PNG (often referred to as an off-system community). For example, representatives from more rural parts of the Fraser Valley described how they wanted access to natural gas service so their communities could benefit economically; however, it was cost prohibitive to get natural gas service to their area.
- Some stakeholders spoke to the lack of natural gas service for communities like the Peace River regional district that provide the necessary labour and infrastructure to support the natural gas extraction industry or those that have large natural gas transmission pipelines running through their neighbourhoods. These stakeholders

pointed out that their communities do not have natural gas service and yet BC generates billions of dollars in government revenue from land sales, extraction and transportation of natural gas and the majority of the provincial resource is exported outside BC. This situation could be further exacerbated by the potential growth of the liquefied natural gas (LNG) export terminals being proposed in BC. These stakeholders felt that they should at least be able to have access to natural gas in their community since they are key to the success of the natural gas industry the provincial economy relies upon.

- The BCSEA expressed that their constituents may only want access to natural gas service in certain circumstances. In BCSEA's words, "BCSEA-SCBC support the use of natural gas where it is justified by net greenhouse gas emissions reductions, air quality improvements, cost effectiveness and other factors. In other situations, BCSEA-SCBC support other energy solutions over natural gas. We do not generally support the concept of extending natural gas service purely to increase "energy choice".[35]

The potential economic benefits of increased access to natural gas service were articulated by many participants. However, participants also expressed that the upfront cost of installing natural gas infrastructure, including any potential CIAC related to system extensions, presented a main barrier to getting access to natural gas service for new customers. A lowering of the CIAC would remove a significant barrier to providing increased energy choice for new customers. Thus, in order to provide energy choice for new customers, FEI in the Application proposes a number of recommendations that help to reduce the CIAC financial barrier, as discussed in Section 4.

3.2.4.2 Protect Existing Customers

The Company put forward a new methodology, the Rate Impact analysis (discussed in section 3.4.3 below), to assess the impact of the addition of new customers to the system over a period of time. This analysis, while not a determination of the economic viability of a main over the life of the asset, does provide a reasonable approach to assessing the impact of customer attachments over the analysis timeframe. This information can be used to assess whether or not the interests of new and existing customers are balanced. Based on this analysis, the rate reductions that have resulted from new system extensions suggest that there is room to amend the MX Test to benefit new customers while still providing protection to existing customers.

To facilitate the understanding of the EES analysis, FEI forwarded a working model of the Rate Impact analysis to stakeholders along with a briefing on how it was constructed, and invited participants to meet individually with EES to review the assumptions in greater detail if required. The Company has continued to refine the Rate Impact analysis since the final workshop.

During the workshops, the Company and stakeholders both expressed that the Company needs to balance the interests of existing customers with those of new customers when considering

[35] Letter to FEI re: FortisBC System Extension Review: Stakeholder Workshops, December 15, 2014 (see Appendix B).

changes to system extension policies. This Guiding Principle is intended to ensure that the interests of new and existing customers remain balanced when considering changes to system extension policies.

3.2.4.3 Support Government Objectives

Throughout the four workshops, there was considerable dialogue about the various provincial government objectives and how best to meet them. There were differing opinions on the relative importance of objectives, the consistency between government energy objectives, as well as the best way to accomplish the objectives. Stakeholders were, however, united in the belief that any proposed changes to system extension policies need to support the provincial government in meeting its objectives.

Expanding access to natural gas service supports the government objectives in two different ways:

1. Providing the public the potential benefits of access to low cost energy, local economic development, the creation and retention of jobs and tax revenue; and
2. Assisting in meeting the legislated greenhouse gas (GHG) emissions targets and related energy objectives set forth in the Clean Energy Act (CEA).

The Company addressed the first government objective in detail in Section 3.2.4.1 above.

The Company and many stakeholders see converting higher carbon energy users to natural gas users as opportunities to support government objectives to reduce GHGs and support the related energy objectives set forth in the CEA. For example, between 2008 and 2014, approximately 10,000 existing, on-main[36] homes in FEI's service territory converted from another energy source to natural gas service. The majority of these homes were on Vancouver Island and typically used heating oil or propane for heating purposes before converting to natural gas. FEI's most recent long term resource plan described how a residence converting from using heating oil for heating to natural gas for heating avoids 1.6 tonnes of carbon dioxide equivalent emissions per year.[37] The Company estimates there are potentially up to 100,000 additional BC homes in its service territory that could convert from a higher carbon fuel to natural gas[38]. These homes are within a relatively close proximity (50 metres) of one of the Company's mains. Additionally, there are approximately 87,000 people living in 180 off-system communities throughout BC that do not have access to natural gas service[39]. These homes are often heated with heating oil or propane; moving to natural gas would reduce emissions. Providing the option to access renewable natural gas (RNG) service would further reduce these emissions.

[36] On-main refers to a customer that does not require a main extension to attach to FEI's system. Also referred to as an "infill" customer.

[37] FEU's 2014 Long Term Resource Plan, pp. 91-92 and 155.

[38] Based on the Company's current Geospatial Information System (GIS) data measuring whether or not a pre-existing dwelling had natural gas service.

[39] Based on GIS data measuring whether or not a community had any natural gas service whatsoever.

3.2.4.4 Recognize First Nations

First Nations can be impacted by changes to system extension policies. As discussed in the workshops, this recognition of this fact can come in different forms and generally is covered in the two previously mentioned Guiding Principles:

- Providing energy choice; and
- Supporting First Nations' government objectives.

In other words, First Nations stakeholders are seeking energy choice, as well as support to meet their own First Nations government objectives. During the workshops, discussion was at a high level as it relates to specific First Nations' government energy objectives.

3.2.4.5 Easy to Understand

This Guiding Principle is straightforward: any changes to system extension policies need to be easily understood, easy to administer by FEI, and stable over time for customers. The MX Test has been largely stable over time, with incremental improvements such as those proposed in this filing.

3.2.5 Consultation Process Summary

The Company's consultative process with stakeholders and work with EES Consulting has contributed to an efficient and transparent review of the Company's customer connection policies. FEI was able to engage in a dialogue with a variety of stakeholders and provide a venue to educate stakeholders on the issues, and to develop the aforementioned five Guiding Principles. The Company obtained preliminary support for updates to its current system extension practices; however, some stakeholders indicated that they would wait until the Company submitted the Application to the Commission to comment on the updates.

The Company considers the consultation to have been a positive process as it resulted in the Guiding Principles, supporting the Company's recommendations discussed in Section 4 of the Application. Workshop materials are included in Appendix B.

3.3 THE OUTCOMES OF THE EVALUATION PROCESS

The review undertaken by the Company and EES, as well as the consultation process, demonstrated that the core elements of the Company's current MX Test and SLCA remain appropriate; however, there are opportunities to make improvements to the MX Test, the SLCA and the Company's current practices with respect to providing alternative methods of recovering CIAC from customers. These outcomes are discussed below.

3.3.1 MX Test

The Company believes that in principle the MX Test continues to be appropriate and should continue to be used. However, there are certain aspects of the MX Test that the Company believes should be amended, including the DCF Term, the customer forecast period, and the overhead allocation.

3.3.1.1 Fundamentals of MX Test Remain Sound

The fundamental components of the Test have been in place for more than twenty years, and the Test has been improved through an iterative process involving periodic updates.

As summarized below, EES made several observations in the 2015 EES Report that support this position:

- Generally speaking, all surveyed system extension tests, including FEI's, compare the cost and benefits of proposed system extensions.
- The incremental pricing approach is the standard method used for determining the need for CIAC payments for system extensions.
- FEI's system extension policies appropriately consider incremental impacts, rather than using a rolled-in treatment of related costs.
- A discounted cash flow (DCF) analysis is the common approach across Canada. Other methods exist, however, all are consistent with the incremental cost theory.
- The use of common inputs in the MX Test is consistent with the theory of amalgamation and postage stamp rates, whereby all customers are treated equally, regardless of location.

Furthermore, regarding the use of the MX Test, EES concluded,

> "*Therefore, we consider the FEI approach to be in keeping with the methods used by other utilities in Canada and the U.S. We do not see any distinct advantages to the internal rate of return method or other approaches, although we would consider them all to be appropriate methods. There is no reason for FEI to change its overall cost-benefit approach at this time as the current approach provides a reasonable assessment of incremental cost analysis.*"[40]

The majority of the input parameters to the MX Test continue to serve the intended purpose. Three areas where FEI sees an opportunity to improve the MX Test are discussed next.

[40] EES Report, Appendix A, page 12.

3.3.1.2 DCF Term

The MX Test currently uses a 20 year DCF term which corresponds with FEI's Integrated Resource Plan[41] (IRP) planning horizon. This approach does not account for the full impact of the benefits of the system extension. The life of the main is a much more relevant DCF term benchmark, and it is consistent with the Guidelines and common in the industry.

While the DCF term corresponds with the IRP timeframe, the DCF term is substantially shorter than the expected useful life of the relevant assets. The IRP term is 20 years, however within the context of the IRP it is not suggested that customers would cease to take service at the end of the 20 year term. Customers are expected to continue being customers after 20 years, but for practical purposes, the IRP only looks out 20 years. An IRP is intended as a tool for identifying long-range infrastructure requirements and resource acquisition strategies[42] whereas a main is the actual physical asset associated with the incremental cost and benefit of a system extension. Therefore, FEI believes that it is more appropriate in the context of the MX Test to account for the full impact of the benefits of the system extension. The 20 year horizon in place currently results in some new customers having to provide a CIAC to access natural gas service when a CIAC is not really required to protect existing customers.

The expected life of the main should be used as the primary reference point for establishing the DCF term because mains represent the largest capital cost component in the construction of a main extension. The 20-year DCF term less than half the expected life of a main. In general, the typical life for distribution mains ranges from 50 to 65 years with significant retirement after 50 years. This is supported by FEI's existing approved depreciation rates. FEI periodically updates its depreciation rates based on depreciation studies. FEI's most recently approved depreciation study was prepared by Gannett Fleming Valuation and Rate Consultants Inc. (Gannett Fleming), a leading firm in North America and was filed as part of FEI's 2012-2013 Revenue Requirement Application[43]. The depreciation study included a review of asset lifespans of various types of infrastructure installed by the Company, including mains, services and meters. Gannett Fleming recommended a 64 year life for mains[44] which was approved by the Commission by Order G-44-12.

Under the Guidelines, a DCF analysis term long enough "to consider the full impact of the extension" is recommended:

> *"The Commission recommends that evaluation of system extensions be based on a DCF evaluation method that includes, to the extent feasible, all incremental costs and benefits associated with a particular system extension over a time period long enough to consider*

[41] The Commission refers to an IRP in Order G-152-07. FEI submits a Long Term Resource Plan (LTRP) to the Commission. For consistency, the term IRP is used synonymously with LTRP in this Application.

[42] FortisBC Energy Utilities (FEU) 2014 Long Term Resource Plan, page ES-1.

[43] FEI has contracted Gannett Fleming to perform an updated depreciation study, using 2014 amalgamated data, which will be filed with the Annual Review materials in the third quarter of 2015. Preliminary indications from the updated study show that there has been no significant change in the asset lives of mains or services from what was approved based on the Depreciation Study filed as part of FEI's 2010-2011 RRA.

[44] FEI Depreciation Study Calculated Annual Depreciation Accruals Related to Gas Plant as at December 31, 2009, pp. II-26.

the full impact of the extension. The Commission also recommends that, as a general principle, the costs of system extensions should be allocated to those customers who cause them".[45]

EES' survey of the practices of other utilities also suggests that 30 to 40 years is a common DCF term.[46]

The Company believes that an update to extend the Company's DCF term is justified and its specific recommendation is provided in Section 4.1.1

3.3.1.3 Customer Forecast Period

A second area where FEI believes that there is room for improvement in the existing MX Test is the customer forecast period. For the majority of main extensions, the current 5 year horizon for customers may be sufficient; however, for projects with a longer horizon, a longer term would be appropriate.

As discussed in Section 2, the MX Test currently allows for a five year window in which to consider the customers added to a main extension and the scope of the build out of the main extension itself. As a result, the PI of a project is contingent upon the number of customer attachments expected to occur in the first five years of a main extension and any customers added beyond the first 5 years have no consideration in the MX Test revenue calculation.

The Company only installs an individual main based on the additions that will occur over a five year period, even if it is more cost effective to install additional main that would be used beyond the five year period. Even if FEI is aware that one main extension project was required in order to access a future development beyond the five year window, this situation is not currently considered in the current main extension planning.

A part of the building process includes the pre-installation of underground utilities such as natural gas, electricity, data and water. If the Company is able to consider that an area will be built out over a period greater than 5 years, it can be more cost effective to install the necessary natural gas infrastructure all at once early in the development process, rather than in discrete segments over time. Installation in a development should occur at the beginning of a project since it is more cost effective to install a main to an area before significant development takes place rather than installing individual segments of main over the course of several years after paving, landscaping and other development may have already occurred. Not only are there fewer encumbrances encountered, the costs would be lower to install given that less time and resources need to be spent on planning, construction work and mobilization. Overall, for most developments with a planning horizon greater than 5 years, the cost of installing the required gas mains all at once would be less than the sum of the total costs of smaller, discrete main extensions over a number of years for the same area.

[45] The Guidelines, pp. 31-33.
[46] 2015 EES Report, Appendix A, p. 14

In addition, there are some circumstances where an initial system extension may require a CIAC that would otherwise not be required if the full impact of the benefits of the main extension were considered. In this type of scenario, if additional customer additions beyond the current five years were considered in the Test, a CIAC wouldn't be required, or it would be less than if the time horizon was limited to five years.

To establish future long term growth potential in a given area, the Company reviews the municipal Official Community Plan (OCP) and zoning plans, and consults with city planners and local developers.

The Commission discussed the issue of sequential extensions in the Guidelines as follows:

> *"With respect to the aggregation of longer system extensions, the Commission believes that there may be situations where two or more system extensions should be reviewed in aggregate. One situation could be where the grouping of contiguous system extensions would likely lead to cost savings due to efficiencies in construction. There may also be situations where an initial system extension that is uneconomic is required prior to subsequent further system extensions which would render the result economic."*[47]

FEI's consideration of a longer planning horizon is consistent with the above passage in that a longer term customer attachment horizon would consider both the potential cost savings and the full impact of the benefits of this type of customer.

While treatment is not uniform, there are examples of other jurisdictions/utilities that use a longer time period to forecast customer attachments. The EES survey found that utilities in Saskatchewan and Ontario currently use a 10 year customer forecast window for all projects.

FEI concludes that the benefits of extending the customer attachment term for longer horizon projects justify an update to its recommended practices. More detail on FEI's specific recommendation is provided in Section 4.1.2

3.3.1.4 Overhead Allocation

A third area where FEI believes that there is room for improvement in the existing MX Test is the overhead allocation. Under the present approach, FEI believes that larger projects are being allocated a disproportionally large share of overhead.

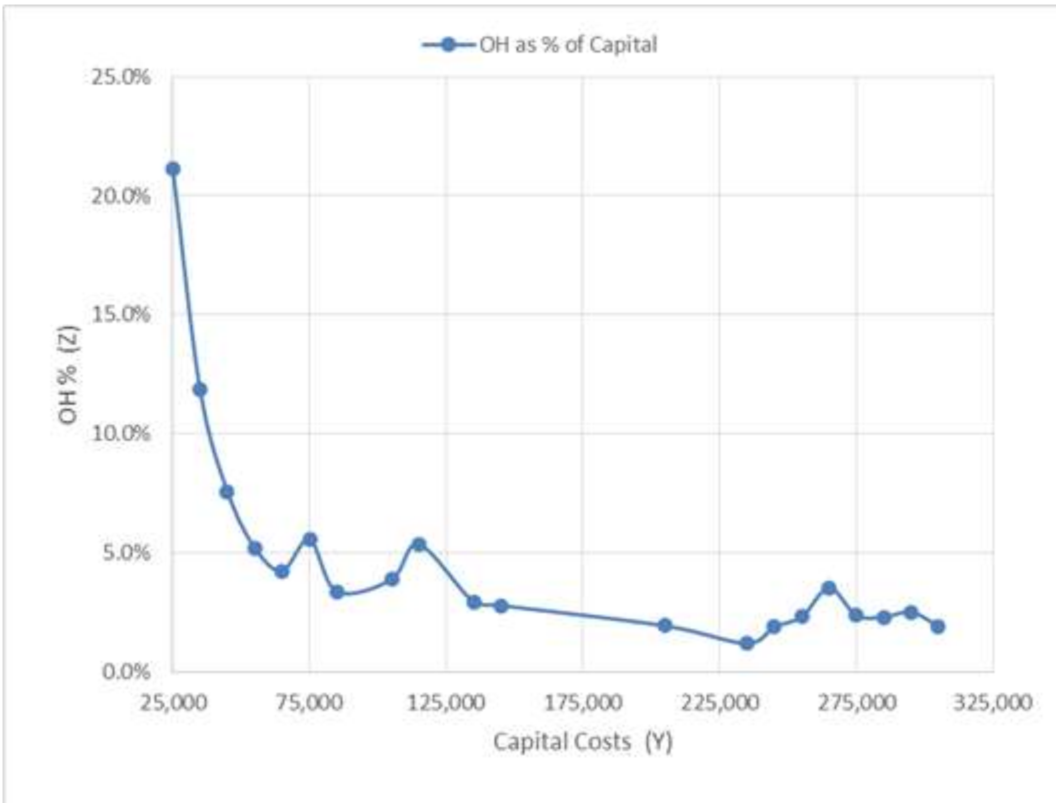
The application of overhead to the MX Test is intended to represent an allocation of general costs that are incurred by the Company to install main extensions that cannot be associated to a particular main extension. The overhead allocation includes, among other items, administrative duties related to mains extensions, right of way management and governmental fees. The

[47] The Guidelines, p. 16.

percentage value for overhead is updated annually. The overhead rate has ranged from 23% to 33% between 2008, with 2014 and at 23%.

Based on FEI's analysis of the relationship between overhead costs and the capital costs of main extensions installed between 2008 and 2014, the overhead costs of a project do not increase linearly with direct capital costs. This is portrayed in the following Figure 3-3; if overhead costs had increased linearly, the blue line would have been flat versus the declining, curving slope that the analysis produces.

Figure 3-3: Overhead as a Percentage of Capital Costs



Given that a linear relationship does not exist between the capital costs for a project and the overhead costs, a flat fee percentage allocation method results in a disproportionate allocation of overhead to projects that have a higher capital cost.

The Guidelines contemplate that as a general principle, the costs of system extensions should be allocated to customers that cause them. And, while treatment is not uniform, there are examples of other jurisdictions/utilities that consider alternate approaches to allocating overhead. EES' analysis cited Gaz Metro as a utility that uses a sliding scale to allocate overhead.

FEI thus concludes that an update to its current practice of allocating overhead to larger projects is warranted. FEI provides its specific recommendation for changes to the overhead methodology in Section 4.1.3 SLCA

The Company also reviewed its service line connections as part of the system connection policy review and concluded that the SLCA construct continues to be appropriate and should continue. The SLCA has been used for more than twenty years, has been approved by the Commission, and continues to serve the needs of customers.

EES reached a similar conclusion:

> *"…it is our opinion that FEI's practice of calculating the SLCA using the MX test and applying that allowance for new customers not requiring a main extension is consistent with standard practice in the industry and within the Province."*[48]

The last time the dollar value of the SLCA was approved was in 2007. To reflect the passing of time since then, the Company believes updating the SLCA value with current data using the same methodology previously approved by the Commission is appropriate. The details of this proposal are in Section 4.2 of this Application.

3.3.2 Recovery of CIACs

Based on the information garnered through the consultative process, the practices of other utilities and the Guidelines, the Company sees an opportunity to introduce an alternative for recovering CIACs from customers.

The Company currently recovers a CIAC from a customer based on the results of an MX Test. In the event that the project is a contributory main[49], the customer paying a CIAC is entitled to a pro-rata refund if a future customer connects within a five year window. The Company currently doesn't provide alternatives for recovering CIACs associated with system extensions.

As discussed in the Section 3.2.4.1, providing a significant CIAC can be a barrier to accessing natural gas service, especially in those areas that are further away from existing mains or less densely populated areas.

The Guidelines contemplate the introduction of additional options for collecting customer contributions related to system extensions:

> *"viable mechanisms for methods for collecting customer contribution would satisfy the following criteria:*
>
> *a) introduce additional options for financing system extensions, thereby reducing the financing pressures on local government (i.e., the use of local taxation mechanisms);*

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[48] EES Report, Appendix X, page 13.

[49] Refers to a main where a customer (s) has made a CIAC.

b) *reduce the incentive for prospective customers to avoid the contribution charge by not applying for connection until after the system extension has been funded and constructed; thus the Commission recommends that, at a minimum, all customers who attach within the first five years to contribute to system extensions;*

c) *ensure that those customers paying an initial contribution are reimbursed as additional customers connect, at least for a reasonable initial period..."*[50]

The 2015 EES Report includes some examples of utilities providing alternative means of providing financing and recovery of CIAC. For example, BC Hydro offers an alternative means of collecting CIAC in the form of a $1.5 million program that has been approved by the Commission for several years[51]. In FEI's view, a similar program could be adopted to help make service more readily available for FEI's natural gas customers.

FEI provides its specific recommendations in Section 4.3.

3.3.3 Service to Off System Communities

In this section, the Company discusses recent trends within industry to further consider natural gas system extensions to off system communities. EES identified that the Ontario provincial government recently allocated over $230 million to promote the adoption of natural gas for off system communities. As a result, FEI understands both Union Gas and Enbridge Gas Distribution intend to file system extension applications to the Ontario Energy Board (OEB) related to the provincial government's introduction of these off system programs. In Quebec Gaz Metro also recently announced a project to extend service to an off system community in the Bellechasse region. The project is jointly funded by the utility and the provincial government and is expected to stimulate economic development, reduce GHGs and save customers money in terms of energy costs. Further, there is a growing trend in the United States of funding expansion that may not pass a traditional extension test. EES noted, *"As with Ontario, most of these practices resulted from either legislation or other government studies/recommendations that promoted the expansion of natural gas."*[52]

In BC, similar government policy promoting the expansion of natural gas to off system communities does not yet exist as it does in Ontario, Quebec and parts of the US. The Company notes that having a supportive government policy is critical to the successful development of a program to serve these types of customers. FEI intends to continue to pursue the need to provide natural gas service to off system communities with the provincial government. Consequently, FEI does not make any related recommendations in this Application.

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[50] The Guidelines, pp. 31-33.
[51] 2015 EES Report, at pages 23 to 24.
[52] 2015 EES Report, page 22.

3.3.4 Summary of the Evaluation Process

In summary, the Company has identified the following opportunities to update its current practices as outcomes of its evaluation process:

MX Test

- The DCF term and customer forecast period should be longer to consider the full impact of system extensions; and
- The overhead costs should be more appropriately allocated to the projects that cause them.

SLCA

- The SLCA value should be updated to reflect the passing of time since 2007.

Recovering CIAC

- The Company should provide an alternative method to recover CIAC from customers.

The opportunities identified above, and others, have been addressed in proposing the recommendations discussed in Section 4 of the Application.

3.4 OPPORTUNITIES TO IMPROVE MX REPORTING & EVALUATION PRACTICES

The need to ensure the necessity and usefulness of compliance reports was one of the recommendations of the Core Review:

> *"The BCUC should make additional efforts to ensure all compliance reports are necessary and useful, and eliminate the reporting requirement for those that are not. The BCUC should place more responsibility on regulated entities to report, on an exception basis, deviations from forecasts that could affect costs and rates, instead of routine reporting."*[53]

FEI believes that there is significant room for improvement in the current reporting structure. The Commission originally identified a purpose of the reporting as being "to determine if the aggregate PI thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1." Annual reporting and the associated processes has, at times, taken on the character of a hindsight review of whether FEI should have undertaken particular extensions.

FEI submits that the objective of the annual MX Reporting should be to affirm the Company's compliance with the MX Test during the reporting period. An assessment of whether "the aggregate PI thresholds need to be adjusted on a go forward basis in order to achieve the

[53] Independent Review of the British Columbia Utilities Commission, Final Report, November 14, 2014, p.31.

aggregate PI of 1.1" is something that would more efficiently be done at larger intervals of time. Moreover, there are better methods of conducting that assessment.

In the sections that follow, FEI discusses:

1. Its current reporting requirements;
2. The issues with the current MX reporting approach; and
3. An alternative framework for assessing the effectiveness of the Company's extension policies.

3.4.1 Current Reporting Requirements

The Commission's use of annual reporting appears to have shifted over time, and the requirements have become more onerous as part of that shift.

Since 2007, the Company has complied with the Commission's reporting requirements set forth in Orders G-152-07 and G-06-08 through its annual MX Reports. Commission staff have, over time, requested a number of additions to the MX Report. These new reporting requests, along with the changes made by the Company, are summarized in Table 3-3 below.

Table 3-3: New MX Report Compliance Requirements Since 2007

Request Made:	New Requirement	Changes Made to the MX Report
Order G-152-07 Order G-06-08 Letter L-19-12	**Report Methodology – Random Sample Reporting**	The Company has utilized the random sample methodology established in Orders G-152-07 and G-6-08.
Email Correspondence with Commission Staff	**Refinement to MX Report Data Tables**	MX data presented in the format provided by Commission staff.
Letter L-67-11	**S.I. Charge Explanation and Update**	The S.I. Charge updated annually, on a go-forward basis.
	Reporting of "Ramp-Up" Factors for Top 5 MX	A "Ramp-Up" factors column provided and populated for Top 5 Cost MX Tables.
Letter L-19-12	**Update to Reforecasting Methodology**	The re-forecasted P.I. value updated to use actual data when available and original forecasts (from the original/initial MX Test) for future years as requested by Commission staff.
Letter L-60-12	**Consumption and Use Per Customer**	All tables updated to reflect an annual consumption and use per customer breakdown.
	Table Segmentation by Rate Class	All new data tables modified to reflect segmentation by rate class.
	Ramp-Up Explanation	Ramp-up explanation provided where applicable.

Request Made:	New Requirement	Changes Made to the MX Report
	Consumption Ramp-Up experience by rate class.	Ramp-up is implemented on a per project basis only. Due to the difficulties in forecasting to such a granular level, the Companies do not conduct individual Ramp-up analysis at the rate class or attachment level; as such the Company does not have data to provide.

The Company has addressed the additional requests of Commission staff. However, the level of MX reporting has become highly dis-aggregated and represents an administrative burden. FEI feels strongly that continuing to incur the time and expense on an annual basis to respond to the increased MX reporting requirements will not deliver benefits in terms of a better understanding of the performance of the main extensions and does not warrant continuing with the current approach.

With the additional requirements imposed over time, FEI's MX reporting practices are much more stringent than is the norm. EES concluded that FEI has the most stringent reporting requirements of the utilities surveyed, and the Company is the only major utility in BC that is required to provide system extension related reporting to the Commission.[54]

FEI submits that a simplified annual MX Reporting will achieve the purpose of monitoring the Company's compliance the MX Test parameters, and provides further information on its proposal in Section 4.4

3.4.2 Issues with Current MX Assessment Approach

Another concern with the shift in focus towards assessing individual extensions, in addition to the efficiency considerations, is that the Commission is employing a methodology that is not suited for that purpose. Specifically, the Commission is re-running the MX Test for certain already completed extensions. Using the current annual MX reporting as a tool to evaluate the performance of completed main extensions does not produce results that are informative about the performance of the main extensions themselves.

3.4.2.1 Purpose of the MX Test and Reporting

The MX Test has been employed by the Commission in the context of annual reporting for the purpose of a hindsight evaluation of the financial impact of a main on customers. The MX Test is neither designed nor equipped for that purpose.

The MX Test is a tool that was developed to determine if the Company can connect a customer under a reasonable set of assumptions. It is a *planning tool* that serves as a practical means for determining whether a main extension to the Company's distribution system should occur when future factors such as actual natural gas rates, overheads, taxes, actual consumption, and actual attachments over the life of the asset are unknown. The MX Test, applied as intended, is

[54] EES Report, Appendix A, p 17.

a forecast analysis used to determine whether or not a customer contribution is required before the proposed main extension proceeds. The true main extension parameters such as revenue and cost can only be assessed or known at the end of the life of the main. The MX Test is not designed to evaluate the financial impact of a main on customers.

The current approach to MX reporting, as it has evolved, is an exercise of re-running the original main extensions test that was conducted at the time a main extension was contemplated, with the best information available at the time, but updated with some actual values for cost, consumption and customer attachments that have been realized at the time the reporting is conducted; while re-forecasting future costs, consumption and attachments. The reporting approach compares the updated PI's produced for reporting purposes with those produced at the time the main extensions were contemplated, with the goal of evaluating the profitability of the main extension at that point in time.

FEI understands that the intended result of this analysis is to indicate the economic impact on existing customers from the Company's main extension activity. The Company submits that the current approach to reporting of comparing forecast to a combination of actuals and re-forecasted information is not meaningful for determining the economic performance of main extensions and does not and cannot indicate if customers have been exposed to an undue cost burden.

The MX Test conducted at the time a system extension is contemplated is based on a forecast. There are a variety of factors at play, and there is a practical limit on the amount that can be invested cost-effectively in refining estimates for main extensions. As such, it is expected that there will be differences between the forecast and what actually occurs. Therefore the comparison of the PI results of an MX Test updated with actual data from the reporting year and other data which is re-forecasted from a different point in time, with the PI results of the original Test does nothing more than highlight the inevitable variances over an arbitrary reporting period. This does not indicate the economic performance of a main extension over its life.

3.4.2.2 Assumption Bias

There are also three assumptions implicit in how the Commission is assessing main extensions after the fact that are invalid and/or may negatively skew the forecast to actual/re-forecast consumption comparisons.

First, the approach assumes consumption as reflected in the MX Test is intended to be a forecast of what new customers on the extension will consume, when in fact it is a credit for consumption based on the usage of *existing* customers that is intended for a different purpose. EES stated:

> *"These average use numbers are not intended to reflect the use of customers in the future but rather reflect the average usage of all customers on the system. That allows new customers to be treated equitably compared to existing customers."*[55]

The 2015 EES Report shows that it is standard practice to use the consumption of existing customers when developing an estimate for revenue.

In essence, evaluating a main extension based on variances of use per customer misses the point. The appropriateness of the credit based on average use per customer does not change simply because the consumption of new customers on a particular extension differs from the rest of the system.

Second, the current reporting approach begins with an original forecast of attachments used in the MX Test, then, when deriving "actuals" for comparison purposes, as requested by Commission staff, the Company is required to assume that delayed attachments do not materialize. The assumption could give rise to a very erroneous conclusion about the economics of an extension. It skews the data and incorrectly results in the updated forecast being lower than the original forecast.

This assumption, since it results in the analysis being so timing-dependent, can also fail to capture what is happening in the new home construction marketplace. The customer attachment forecast is based on the data available at the time, derived directly from customers, municipal building and permit plans and FEI's industry experience. However, attachments can be delayed when outside events impact the marketplace. For example, the financial crash of 2008/09 delayed many customer attachments until the market recovered. Builders and developers are highly motivated to sell their properties to homeowners and re-coup their investments. The longer lots sit unsold, the greater the carrying costs, the lower the profit margin. This means that builders and developers will continue to pursue attachments and, although delayed, they will usually materialize.

Third, the analysis that FEI is required to undertake in the MX Report does not produce actual results, but rather produces an updated forecast. It re-runs an original MX Test, at future annual intervals for the first five years coinciding with the annual reporting cycle, but updated with actual costs, project to date attachments, actual volumes to date and re-forecasted future attachments and volumes at that point in time. There remains considerable uncertainty in the updated analysis.

For these reasons, the current reporting approach does not produce results that are meaningful or indicative of the economic performance of a main extension. The current practice of using the MX Report information for evaluating the performance of individual main extensions should be discontinued. The focus should be on compliance with the MX Test and how to assess the parameters of the Test itself.

[55] EES Report, Appendix A, p.14.

3.4.3 Alternative Framework for Assessing the Effectiveness of System Extension Policy

In this section, FEI addresses an improved approach (the Rate Impact approach) for assessing whether or not the MX Test is achieving its intended result. FEI is proposing that this Rate Impact approach inform any future changes to FEI's system extension policy. Specifically, FEI proposes to conduct the Rate Impact analysis at the time of any future reviews of the system extension policies to help guide the review.

3.4.3.1 Overview of the Rate Impact Approach

The only way to truly determine the economic benefits of a main is after the passage of a material portion of the economic life of the main. As it is impractical to evaluate mains after a period of 50 or more years, FEI, with support from EES, developed a methodology for analyzing the aggregate impact on customer rates from adding new customers over a past period of time. The Rate Impact analysis does not determine if a main or aggregate of mains is economic, but it does provide a better "point in time" view on the impact that new customers have been having on existing customers, and can serve as a reasonable assessment of the functioning of the system extension policies and MX Test. A full description of the methodology and supporting data can be found in the 2015 EES Report[56]. The following provides a summary of EES' findings.

In simple terms, the Rate Impact analysis looks at what customer rates would be in aggregate with and without actual, historical system extensions installed within a predetermined period (EES used 2008 to 2014[57] in its analysis). This point in time analysis considers whether the incremental revenue and cost of extensions completed in the predefined timeframe raises or lowers customer rates, all else equal. If rates with capital growth equal rates without capital growth, it indicates a balance of new and existing customer interests having been met. If the rates are not equal, the Company may want to consider changes to its policies.

The 2015 EES Report provided the following observations about balancing the interests of new and existing customers:

> *"Existing customers should not receive all of the benefits of efficiencies and economies of scope related to new customers, thereby lowering their rates as a result of new customer growth. It is important to strike the proper balance where both new and existing customers are paying their share of the costs they cause and neither group is cross-subsidizing the other group."*[58]

It is important to emphasise that the use of a short timeframe in the Rate Impact analysis rather than the useful life of the main, in and of itself, has shortcomings in that the future effect of

[56] Appendix A, p.22-27
[57] 2008-2014 was chosen because it represents the time period since the Company's last system extension review in 2007 and the present.
[58] EES Report, Appendix A, p.9.

revenues or growth are not known. While not perfect, the Rate Impact analysis provides a more reasonable means to assess the effectiveness of system extension policies over a shorter term.

3.4.3.2 Results of the Rate Impact Approach

Within the time frame analysed in the Rate Impact analysis, EES concluded that customer rates have decreased as a result of historical system extensions, meaning that existing customers appear to have benefitted from overall system extensions that occurred from 2008 to 2014. In its most recent report, EES has determined that customer rates have gone down by over $10 per year, equivalent to $0.058 per gigajoule (GJ), as a result of customer growth.

Since the analysis shows that FEI's customers have benefitted through lower rates as a result of historical system extensions in the timeframe reviewed, there is an opportunity to update the Company's policies and still balance the interests of both new and existing customers.

3.4.4 Summary of MX Reporting and Evaluation

The Company believes that the current practice of using information in the MX Report for evaluation of the MX Test parameters and the economics of a past extension should be discontinued. The Company is proposing to provide the following to the Commission going forward:

- A simplified MX reporting structure to be provided on an annual basis that focuses on FEI's compliance with the MX Test, and
- A periodic review of whether or not the MX Test is achieving its intended result, informed by the Rate Impact analysis.

Further details of the Company's proposal are found in Section 4.4.

3.5 *SUMMARY OF EXTENSION POLICY REVIEW*

Consistent with past practices of periodically updating its system extension polices, it is an appropriate time to consider changes to FEI's MX policies to reflect the passing of time since they were last reviewed in 2007. The Company's review of its system connection policies generated three overall conclusions:

1. A consultative process with a wide variety of stakeholders was a valuable component of FEI's review;
2. Reviewing aspects of FEI's current policies is warranted; and
3. There are more efficient and meaningful ways to assess system extension policy than those inherent in the current MX reporting and evaluation practices.

The following section provides more detailed recommendations in response to the general conclusions provided above.

4. RECOMMENDATIONS

The recommendations that follow have been developed in response to the findings of the review of the Company's system extension policies described in Section 3. More specifically, the Company recommends updates to the MX Test, the SLCA, the creation of a system extension fund, and improved MX reporting. The details on each recommendation are provided below. The adoption of these proposals will result in an improved, and just and reasonable MX Test and SLCA and appropriate reporting.

4.1 *MAIN EXTENSION TEST*

As discussed in Section 2 of the Application, the Company has been using the same MX Test methodology since 1993, with a number of updates approved by the Commission over the years. Section 3 demonstrated that the MX Test continues to serve its purpose, but will benefit from certain updates.

FEI is thus recommending the continuing use of the current MX Test with four updates to the current practices as summarized in the table below:

Table 4-1: MX Test Recommendations

MX Test input	Current Practice	Recommended Update
DCF Term	20 years	40 years
Customer additions	5 year estimate	10 years for main extensions with a build out horizon greater than 5 years.
Overhead	Flat rate for all main extensions	Sliding scale for projects with a capital cost greater than $25,000
Energy efficiency credit	Applying to high efficiency appliances	Discontinuing the use of energy efficiency credits

The four recommendations above are provided for consideration as an integrated proposal as there are both positive and negative impacts to the MX Test.

The Company is recommending continuing with the current practices for the remaining inputs into the MX Test, as discussed in Section 2.2 of this Application, *Current System Extension Constructs*. Each of the four MX Test recommendations set out in Table 4-1 is discussed in greater detail below.

4.1.1 Discounted Cash Flow Term

The review of FEI's system extension policies suggested that extending the current 20 year DCF term is justified because the 20 year approach does not account for a reasonable time period over which to estimate the benefits of the system extension. A time frame that incorporates the majority of the life of the main is a much more relevant DCF term benchmark, and it is consistent with the Guidelines and there are also comparable industry examples.

The Company is recommending a 40 year DCF term. Although a longer DCF term may also be justified as it more closely aligns with the life of the main and captures more of the benefits, the Company is proposing to limit the DCF term to 40 years, as it covers the majority of useful life of the main.

4.1.1.1 Analysis of DCF Term

The following section analyzes the impact of a 40 year term on the incremental revenue in the Test, CIAC and impact on rates. By extending the term to 40 years, the incremental revenue of new customers will be more accurately captured in the Test. This will result in a smaller percentage of customers paying a CIAC, and a reduced amount of a CIAC for those that do pay while still protecting the interests of existing customers.

The Company conducted an analysis of the mains installed between 2008 and 2014 to determine the impact of extending the DCF term to 40 years on:

- the revenue and costs in the MX Test;
- the percentage of MX Tests requiring a CIAC; and
- customer delivery rates.

Between 2008 and 2014, 5,492 mains were installed by the Company. FEI conducted a CIAC analysis using a proxy version of the 2015 MX Test since it would be impractical to re-run thousands of individual MX tests to determine the impact on each CIAC by extending the DCF term. The analysis was run using sensitivity scenarios with different consumption, capital costs and DCF terms to estimate the potential reductions in customer contributions as a result of considering longer DCF time frames in the MX Test.

The consumption scenarios were as follows:

- 68.3 GJ represents a new customer;
- 84.2 GJ represents an existing customer; and
- 58.8 GJ represents a new customer with low consumption.

The capital cost scenarios were as follows and were based on the 2008-2014 actual mains:

- $1,060 represents the average of the lowest 10% of main extensions by cost;

- $11,600 represents the average main extension cost;
- $50,000 captures 97% of all main extensions; and
- $500,000 represents a very large main extension.

Finally, in addition to the recommended 40 year DCF, FEI considered DCF time frames of 30, 35, 45 and 50 years.

Impact on Revenue & Costs in the MX Test

To understand the potential impact on revenue and cost in the Test, FEI ran a number of proxy MX Tests varying the consumption, capital cost and DCF term.

Table 4-2 below summarizes the increase in revenue associated with various increases in the DCF term in each of the four capital cost scenarios. For example, in one scenario, the DCF term was 40 years, the capital cost was $11,600 and FEI varied the consumption between 58.8 GJ, 68.3 GJ and 84.2 GJ to determine the impact on revenue. In this example, the revenue calculated for the MX Test increased by 41.3% to 43% with an average of 42.2%.

Table 4-2: Impact on MX Test Revenue of Extending the DCF Term (% increase)

DCF Life	$1,060 (Bottom 10%)	$11,600 (Average)	$50,000 (Captures 97%)	$500,000 (Large Project)
30	26.4%	26.2%	25.6%	29.3%
35	34.7%	35.2%	34.3%	39.0%
40	**42.5%**	**42.2%**	**41.1%**	**46.8%**
45	48.1%	47.7%	46.4%	52.3%
50	52.4%	52.1%	50.6%	56.8%

The Company notes that the MX Test will have to be updated in order to accommodate the additional capital costs associated with using a 40 year DCF analysis. Since 40 years exceeds the 20 year life of the meter and regulator[59], the Company proposes to include a replacement cost in year 20 for these assets as part of the MX test. This amount will be determined as the initial cost of the meter and regulator specific to each main extension project and will be translated into a present value to be used in the PI calculation. The Company expects this to have an immaterial impact on the PI due to the low capital cost of a meter and regulator and the 20 year discounting of the cost. The expected life of a service is 50-65 years, and since this asset's life is beyond the 40 year proposed DCF term, no proxy is needed for this cost.[60]

In summary, increasing the DCF life from 20 to 40 years is expected to increase the revenue in the MX Test by between 41 percent to 47 percent depending on the cost of the main extension

[59] Exhibit B-1, Appendix E FEU 2012-2013 RRA Proceeding - FEI Depreciation Study Calculated Annual Depreciation Accruals Related to Gas Plant as at December 31, 2009, pp. II-30.

[60] Ibid. pp. II-28.

and the customer's consumption. Increasing the DCF term to 40 years will have no impact on the capital costs in the Test since the life of the main and the service line both exceed 40 years and the impact of an assumed meter and regulator replacement at 20 years will have an immaterial impact on the MX Test results.

Impact on the Percentage of MX Tests Requiring a CIAC

After determining the change in revenue associated with extending the term, and considering that there are no changes in capital costs as a result, the Company next looked at the impact on CIAC by moving from 20 years, the reference point of the analysis, to a 30 to 50 year DCF term.

Ten percent, or 551, of the 5,492 mains installed between 2008 and 2014 required a CIAC, totalling $3.9 million. By increasing the DCF from 20 to 40 years, the CIAC would have decreased by approximately $2.0 million in total and 4.8% of customers would have paid a CIAC, as shown below. The number of customers paying a CIAC would consequently go down from 551 to 261 by switching from the current 20 year DCF term to a 40 year DCF term.

Table 4-3: Decrease in CIAC from Extending the DCF Term

DCF Term	20	30	35	40	45	50
Present Value of Revenue ($000)	$9,128	$11,573	$12,399	$13,053	$13,550	$13,944
Total CIAC Received ($000)	$3,860	$2,392	$2,104	$1,913	$1,779	$1,689
Decrease In CIAC ($000)	$0	(1,468)	(1,756)	(1,947)	(2,081)	(2,171)
Change in Cost per GJ (exc. Cost of Gas)	*$0.000*	*$0.001*	*$0.002*	*$0.002*	*$0.002*	*$0.002*
Total Number of CIAC	551	338	291	261	245	236
% of Main Extensions Paying CIAC	10.0%	6.2%	5.3%	4.8%	4.5%	4.3%

By extending the DCF term from 20 to 40 years, new customers receive a benefit more commensurate with the life of the main and consequently are less likely to pay a CIAC to access natural gas service.

Impact on Existing Customers' Rates

The Company measured the impact on rates by considering the $2.0 million decrease in CIAC that would result from an increase in the DCF term to 40 years. The Company used the Rate Impact model developed by EES Consulting to determine the impact on existing customer rates. Assuming the 40 year term was in place in 2008 and all else being equal, the approximate $2.0 million reduction in CIAC for all main extensions installed between 2008 and 2014 would have resulted in an increase in rates of $0.002/GJ.

It is worth noting that the Company did not factor into the Rate Impact analysis the likelihood of new, incremental customers connecting to the system via a main extension who had previously decided not to secure natural gas service because of a more onerous CIAC. Directionally, these customers would have an off-setting, positive impact on rates (i.e. rates would go down, other things being equal) because of the same logic and methodology as is set out in the EES Report. Hence, in the analysis above, the Company has used a conservative approach to measure the rate impact.

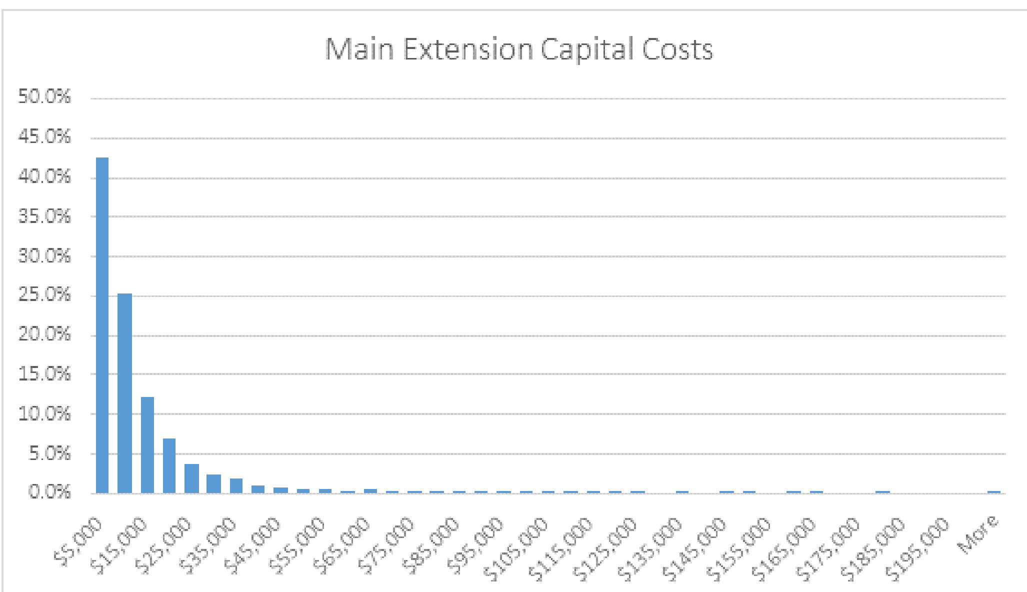
In summary, moving from a 20 year to a 40 year DCF term will help lower the CIAC barrier in a manner that remains fair to existing customers.

4.1.2 Customer Addition Estimate

This section details FEI's recommendation for the use of an MX test with a 10 year horizon for customer addition estimates for main extensions with a longer term build out horizon, to better capture the benefits relating to these developments. The Commission referred to this type of situation in the Guidelines as either 1) the grouping of contiguous system extensions or, 2) a situation where an initial system extension that is uneconomic is required prior to a subsequent further system extension which would render the aggregate result economic.[61]

Based on feedback from customers and the Company's experience in the new construction marketplace, FEI estimates that there will be a relatively small number of these main extensions every year. These main extensions are expected to have a higher capital cost than the average main cost which is $11,600. Figure 4-1 below show the frequency distribution of actual main extension costs for projects installed between 2008 and 2014.

Figure 4-1: Main Extension Capital Cost Frequency Distribution



[61] The Guidelines, page 16.

As seen above, between 2008 and 2014, the majority (90%) of main extension costs are $25,000 or less and only 10%, or 549, out of 5,492 mains comprised the balance. Three main extensions had a cost greater than $500,000.

4.1.2.1 Recommendations for Customer Addition Estimate

The Company proposes to use a 10 year horizon for customer attachments in certain circumstances when it can be reasonably demonstrated by the customer or municipality that there is a longer term municipality-accepted plan for growth exceeding five years. The eligibility for the use of a 10 year customer addition forecast in the MX Test will be limited to developers and municipalities on a case by case basis. Requests will be evaluated throughout the year by FEI. FEI will utilize the following types of data to determine if a planning horizon period greater than 5 years is appropriate for use in the MX Test of a given project:

- Municipal Official Community Plans;
- Zoning plans;
- Discussions with municipal city planners;
- Evidence of commercial commitments having been made with developers; and
- The various options available to the Company to install a main (s) to serve the area.

The Company is also recommending including a summary of the 10 year customer addition forecast projects in its annual MX reporting. Specifically, the Company will provide the following:

- The number of main extensions using a 10 year customer addition forecast;
- The actual costs for the mains; and
- The number of customers providing a CIAC and the dollar value of any CIAC provided.

The Company believes the revenue for these longer horizon system extensions will be more fairly represented using a 10 year horizon. Additionally, the Company expects improvements in the efficiency and cost to install these types of main extensions by taking a longer term view. However, it is impractical to estimate the rate impact of this recommendation.

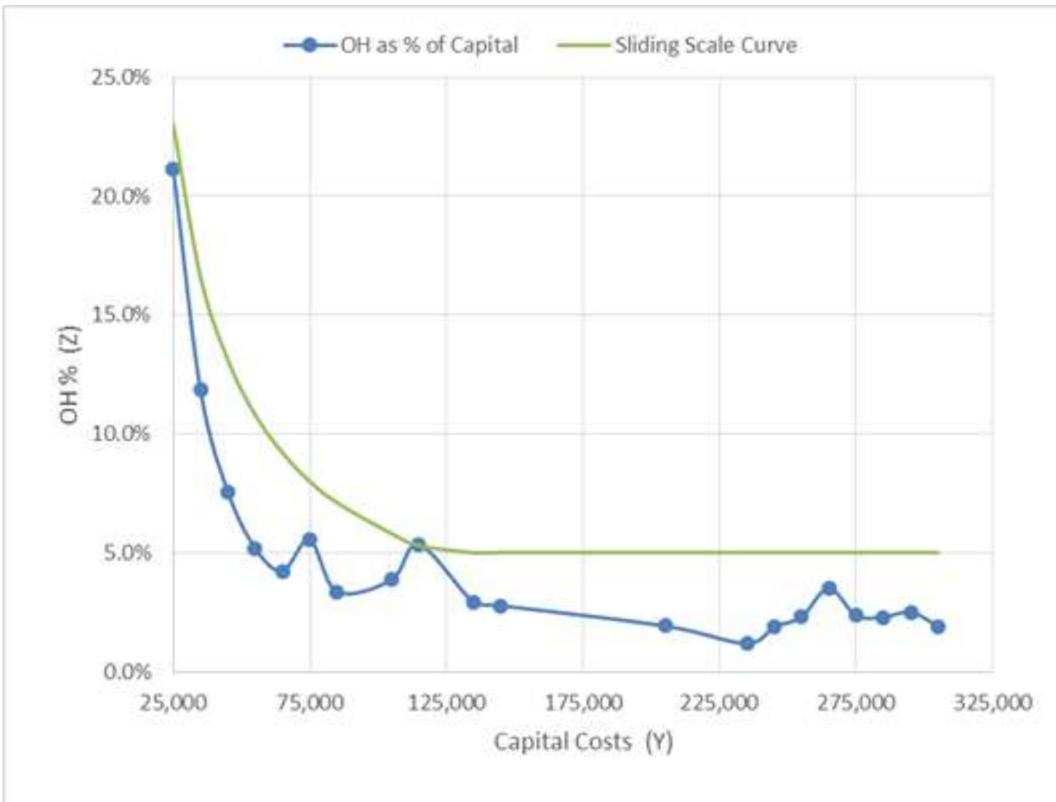
4.1.3 Overhead

This section provides FEI's recommendation to continue its current practice of allocating a fixed overhead percentage to the vast majority of its projects. For larger main extension projects, the Company proposes to apply a sliding scale overhead percentage. The intent of this recommendation is to more accurately allocate the overhead costs to these larger projects.

FEI is recommending a sliding scale overhead rate for projects with direct capital costs greater than $25,000. The annual overhead percentage applied would decrease based on the percent of direct overheads to direct capital costs. The overhead rate would have a floor equal to five per cent.[62]

As discussed in the Section 3.3.1.4, overhead costs do not have a linear relationship to the direct capital cost of a main extension. The relationship is demonstrated in the following Figure 4-2 where overheads as a percentage of capital costs are graphed in a scatter plot (solid blue line with markers).

Figure 4-2: Overhead as a Percentage of Capital Cost & Sliding Scale



Based on the data, an exponentially declining equation is a suitable approach to scale down the overhead percentage for larger main extension projects. FEI used a starting percentage of 23% (which represents the overhead rate for projects with a capital cost of $25,000 or less) to produce a sliding scale curve that has a starting point of 23% and then decreases as direct capital costs increase (solid green line without markers). This resulted in an exponentially decreasing overhead rate that has the same curve that the data produced.[63]

[62] Applying the Sliding Scale Curve (solid green line without markers in Figure 4-2) overhead formula to projects with large capital expenditures would result in a lower overhead amount than for a project with a very small capital expenditure. Therefore an overhead rate floor is required to help ensure a larger project will attract more overhead costs than a smaller project within the MX Test.

[63] Note that a 5% overhead rate is used as a floor.

The following is the proposed overhead rate methodology scale based on the sliding scale curve in Figure 4-2:

<u>Main Extension Capital Cost of $25,000 or less:</u>

- The MX Test will use the annual fixed overhead rate.

<u>Main Extension Capital Cost of greater than $25,000:</u>

- The MX Test will calculate the overhead rate as set out in the formula below.

$$Z = Greater\ of\left(\frac{X}{25{,}000^{-0.963}} \times Y^{-0.963}\right)\ AND\ 5\%$$

Where:
X = Annual fixed overhead rate
Y = Capital cost of project (before overheads applied)
Z = Overhead Rate used for this project in MX Test

As an example, a project with a direct capital cost of $20,000 would be subject to the full overhead rate in the MX test, currently 23%. This would result in a total capital cost of $24,600 ($25,000 + $4,600 in calculated overhead).

A larger project with a direct capital cost of $100,000 for example, would be subject to the sliding scale overhead formula. The sliding scale overhead rate would be 6.0%[64] using the formula above. This would result in a total capital cost of approximately $106,000 ($100,000 + $6,000 in calculated overhead).

4.1.3.1 Analysis of Sliding Scale Overhead

The Company revisited all mains installed from 2008 to 2014 in order to assess the impact of the proposed overhead methodology on the CIACs of all main extensions in that timeframe and the potential rate impact. The total overhead amounts were re-calculated for all main extensions by taking the total capital used in the existing MX Test and applying both the fixed overhead rate at that time as well as the proposed sliding scale overhead rate for projects with a capital cost greater than $25,000.

All else being equal, the decrease in overhead costs for those projects with a CIAC would have resulted in an equivalent reduction in the required CIAC amount. Table 4-4 below provides the results.

[64] $(0.23 \div 25{,}000^{-.963}) \times 100{,}000^{-.963}$ = .0605, Rounded to 1 decimal place = 6%. This is greater than 5% so 6% is used.

Table 4-4: Analysis of Sliding Scale Overhead Calculation

	Fixed Annual Overhead Rate	Sliding Scale Annual Overhead Rate	Difference
2008 to 2014 MX Test Overhead ($000)	$3,444	$ 1,839	$1,605
Number of CIAC	551	538	13
% of Total	10.0%	9.8%	0.2%
Total CIAC ($000)	$3,860	$ 2,819	$1,041
		Change in Cost per GJ (exc. Cost of Gas)	$0.001 / GJ

As seen above, by applying a sliding scale for the overhead allocated to capital projects greater than $25,000 in the MX Test, only 13 main extension projects would be affected by a lower CIAC, equivalent to a 0.2% reduction in the amount of CIAC received. Using the Rate Impact methodology discussed earlier in the Application, the reduction in the CIAC amount of $1,041 thousand would have a minimal impact on rates of $0.001 / GJ.

4.1.3.2 Overhead Summary

FEI proposes to continue its current practice for calculating the overhead rate for main extensions with a direct capital cost less than $25,000 and to apply a sliding scale to calculate the overhead rate for main extensions where direct capital costs are greater than $25,000. The Company expects that this change will more fairly allocate the overhead costs while at the same time, existing customers will not be negatively impacted.

4.1.4 Energy Efficiency Credits

The Company is proposing to eliminate the use of energy efficiency credits as energy efficiency is now being driven by our demand side management (DSM) program, and the MX Test will be easier to understand and administer as a result.

As discussed earlier, in Order G-152-07, the Commission approved the use of the following credits to promote energy efficiency:

- For customers with high efficiency gas-fired space heating and water heating, a consumption credit of +10% of the volume otherwise used for both appliances; and
- For customers who have both high efficiency gas-fired space and water heating appliances as defined above, and who attain a minimum of LEED General Certification: a consumption credit of +15%.

At the time the Commission approved the energy efficiency credits in 2007, the Company had a modest DSM program with an annual budget of $3.1 million, excluding partner investment. In contrast, the Commission has approved the Company's DSM program with an annual budget of approximately $35 million over the period 2014-2018.

The Company believes that its current DSM program meets the needs of promoting energy efficiency; therefore, the energy efficiency credits in the MX Test are no longer required for that purpose. Furthermore, the REUS data used to estimate the consumption per customer already reflects the success of the Company's DSM programs, as seen in the gradual decline in the use per customer (UPC). In other words, as customers live in more energy efficient buildings and use more energy efficient appliances, their UPC is declining. In turn, these declining values are reflected in the MX Test.

A beneficial outcome of discontinuing the use of energy efficiency credit is to make it easier to customers to understand and for the Company to administer its use in the MX Test. Only six percent of main extensions completed from 2008-2014 used the 10 percent credit and less than 1 percent used the 15 percent credit.

It is impractical to re-run the MX Tests to determine the rate impact of discontinuing the energy efficiency credits. Directionally, this update will offset other updates in that it will decrease the consumption per customer in the MX Test and increase the likelihood of a CIAC being paid by the customer.

4.1.5 Cumulative Impact and Summary

In summary, the Company is proposing the following related to the MX Test:

1. Continuing to use the current MX Test while keeping the majority of the existing components of the Test unchanged from current practices;
2. Extending the DCF term from 20 to 40 years;
3. For projects with a planning horizon greater than 5 years, extending the customer addition forecast from 5 years to 10 years;
4. Apply a sliding scale to allocate overhead to projects with a direct capital cost greater than $25,000; and
5. Discontinuing the use of energy efficiency credits.

FEI believes that these changes will help promote access to natural gas service for those who want it, while maintaining a reasonable balance with the effect on existing customers. Based on the analysis FEI undertook, the estimated annual cumulative rate impact of all of these changes is approximately $0.003 per GJ as follows:

Table 4-5: Approximate Delivery Rate Impact of Recommendations[65]

Recommendation	Approximate Rate Impact ($/GJ)
Extending DCF Term to 40 years	$0.002
Extending Customer Additions forecast to 10 years	-
Sliding Scale Overhead	$0.001
Discontinue Use of Energy Efficiency Credits	-
	$0.003

To provide some context, $0.003/GJ is equivalent to an annual impact of $0.53 for each FEI customer. In addition, the estimates above do not consider the potential benefit of increased system extension installations and resulting customer additions and load that may result.

In comparison, the benefit that EES calculated for existing customers from historical system extensions installed from 2008 to 2014 was significantly higher at $0.058/GJ, equivalent to over $10 per customer annually, providing support for the conclusion that customers will continue to benefit from extension policies with these recommendations in place.

4.2 *SERVICE LINE COST ALLOWANCE*

As discussed earlier, the current SLCA has been in place since 2007, and the methodology for calculating the SLCA has remained essentially unchanged since it was first approved by the Commission in 1996. The Company recommends the continued use of the SLCA methodology but with an update to the calculated amount of the SLCA. In this section, FEI demonstrates that, using the same methodology as in past years, an increase to the SLCA for single family dwellings to $2,150 and duplexes of $4,300 is appropriate.

A description of the historical methodologies used in 1996 and 2007 follows along with an analysis of the recent 2014 data and the SLCA recommendations.

4.2.1 Review of 1996 and 2007 Methodology

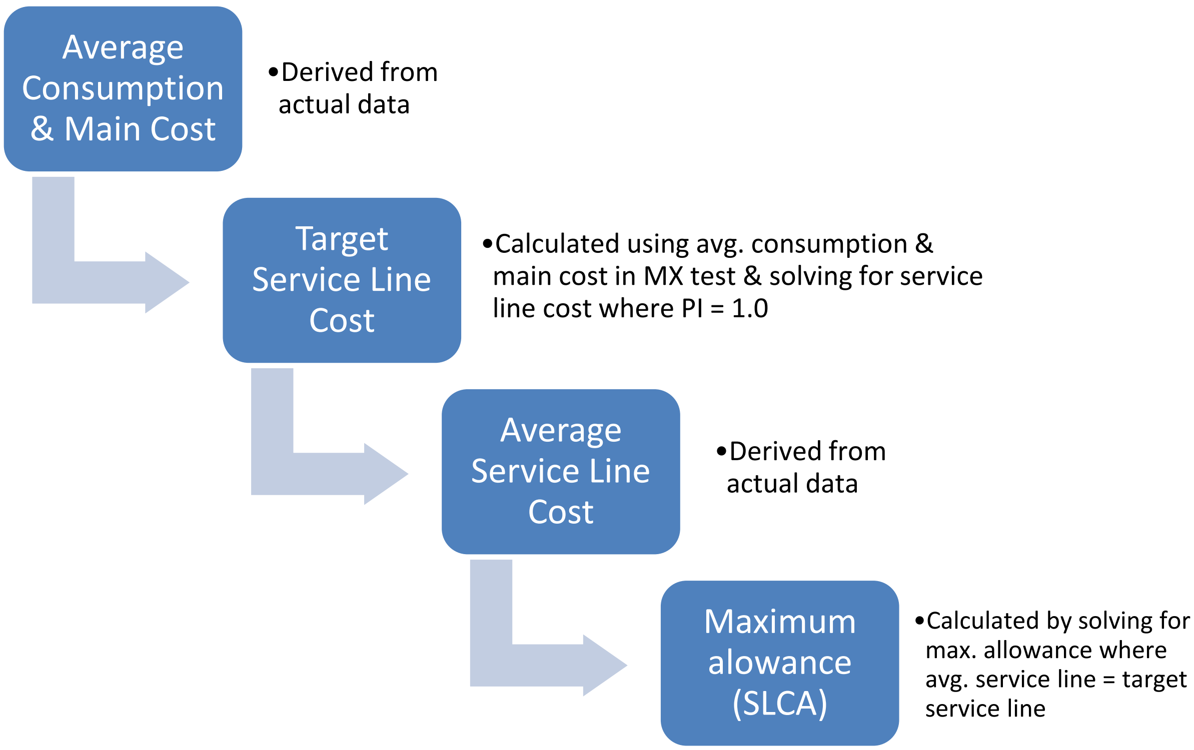
The current SLCA of $1,535 for single family dwellings (SFD) was determined in 2007 using the same methodology as was used in the 1996 application that was approved by the Commission. The SLCA for duplexes is simply calculated as two times the SFD SLCA.

Under the 2007 methodology, the SLCA is a derived value that represents a proxy MX test for a residential customer where the PI equals 1.0. In other words, the SLCA represents a value where the revenue equals the cost to install an average service line. The SLCA is calculated using a combination of actual consumption, service line and main extension cost data.

[65] There may be a small impact from the 10 year customer addition forecast window for certain projects; however, this will likely be offset by the small positive impact from the discontinuance of energy efficiency credits.

A simplified depiction of steps to determine the SLCA is found below.

Figure 4-3: SLCA Methodology



A more detailed illustration of the methodology follows, using data from the 1996 application as an example. The average main cost per new customer added to the system at that time was $516. A target service line cost that would support a PI of 1.0 in a proxy MX test was calculated to be $475 based on an average normalized consumption of 123 GJ per year and an average main cost of $516. The actual average cost of all new service lines completed in the period from January to September of 1996 was then determined to be $659. Finally, the 1996 actual service line cost was evaluated further to determine the maximum allowance (i.e. the SLCA) that would result in reducing the average service line cost to equal the target cost of $475. The resulting SLCA was $1,100.

In 2007, the Company followed the same SLCA methodology as in 1996. As seen in the table below, the one exception was that the Company provided additional, average consumption sensitivity scenarios to reflect future trends and a scenario whereby the Mainland SLCA equalled the Vancouver Island SLCA.

The inputs into the SLCA calculation from the 1996 and 2007 applications are summarized as follows:

Table 4-6: SLCA Historical Data (1996 & 2007 Applications)

	FEI (1996)	FEI Mainland (2007)			FEI Vancouver Island (2007)		
Average consumption (GJ)	123	96.9	90	80	60.2	66	61
Average main cost	$516	$620	$620	$620	$1,086	$1,086	$1,086
Target service line cost	$475	$1,181	$1,064	$910	$1,072	$1,250	$1,093
Average service line cost	$659	$1,161	$1,161	$1,161	$1,573	$1,573	$1,573
Maximum allowance	$1,100	>$3,500	$2,925	$1,535	$1,473	$1,473	$1,535
% of Customers > Maximum	13%	0%	8%	19%	35%	21%	36%

The SLCAs approved by the Commission following the 1996 and 2007 applications were $1,100 and $1,535 respectively. However, the effective SLCA between 1996 and 2007 was $1,100 minus the $215 SLIF (i.e. $885) because the SLIF was an additional fee to be borne by the customer which effectively reduced the SLCA during the time that it was in place.

The percentage of customers where the estimated cost of the service line and meter was greater than the SLCA (i.e. those that would have to pay a contribution) in 1996 was 13%. In 2007, the percentages for Mainland and Vancouver Island were 19% and 36% respectively.

4.2.2 SLCA Analysis

To determine the SLCA for this Application, the Company analyzed 2014 data using the same methodology that was used in the 1996 and 2007 applications. Table 4-7 summarizes the relevant inputs.

Table 4-7: SLCA 2014 Data Analysis

	FEI 2015	
Average annual consumption (GJ)	84.2 GJ	68.3 GJ
Average main cost	$745	$745
Target service line cost	$1,974	$1,521
Average service line cost	$2,125	$2,125
Maximum allowance	$4,775	$2,150
% of Customers > Maximum	7%	33%

FEI's normalized annual consumption for existing residential customers was 84.2 GJ in 2014. 68.3 GJ is a scenario representing the normalized average annual consumption of residential customers that connected to FEI's system between 2008 and 2014. In order to be consistent with the 2007 approach, the Company is proposing to use 68.3 GJ as the base case for analysis and recommendations.

As provided in Appendix D-2, FEI's average main cost was $745 per customer in 2014. When $745 is inputted into the existing MX Test along with 68.3 GJ for annual consumption, the result is a target service line cost of $1,521 when solving for a PI equal to 1.0. Appendix D-2 provides a summary of all 2014 service line costs for Rate Schedule 1 and Rate Schedule 2 customers showing an average service line cost of $2,125. Solving for the equation where the average service line cost equals the target service line cost, a maximum allowance of $2,150 is derived; this would result in 33% of customer costs being greater than the SLCA.

4.2.3 SLCA Recommendations

The Company is proposing an SLCA of $2,150 for single family dwellings and $4,300 for duplexes for 2016. The proposal reflects that:

1. The use of the SLCA continues to be an appropriate construct to meet the needs of customers; and
2. FEI has followed the same methodology approved by the Commission following the 1996 and 2007 MX applications, but with current inputs.

The Company is also proposing to update the SLCA annually, as it does with other MX Test parameters. In this way, FEI will be treating customers the same each year and not in a manner that leads to intergenerational inequity. Specifically, the Company will file an SLCA analysis and updated values in November each year following the same methodology it has used in 1996, 2007 and in the current Application. FEI expects that the SLCA value and tariff updates would be approved by end of the calendar year for implementation January 1 of the following year. For example, in November of 2016, the Company will file a request to the Commission to approve a revised SLCA value which would be effective January 1, 2017.

4.3 *CREATION OF A SYSTEM EXTENSION FUND*

The following section recommends the creation of a $1.0 million system extension fund (the Fund) designed to create greater equity between new customers in lower density areas of FEI's service area with those new customers in more urban areas. There is a sound rate design rationale for this proposal and also a BC precedent.

4.3.1 Policy Rationale and Precedent

While the standard policies regarding the SLCA and MX Test work well for assessing new residential subdivisions and infill customers in the more developed portions of the Company's service area, customers that are located in areas with lower density will naturally have a more difficult time meeting the PI required under the test and therefore will be required to pay a larger CIAC in order to obtain natural gas service. Because of the size of the CIAC required to connect individual customers in areas further from existing mains, mains are often not extended. While this reflects the theory of incremental pricing for new customers, there remains a sound rate design rationale to adopt a different approach. There is a BC precedent for a fund and the rate design rationale for the fund is consistent with factors supporting the recently approved amalgamation and common rates established for FEI.

As discussed in Section 3.3.4, BC Hydro has had a mechanism to accommodate these types of customers through its Uneconomic Fund for many years. BC Hydro's Uneconomic Fund is recovered through BC Hydro's electric rates and is capped at $1.5 million per year. It has been in place for roughly 30 years. Applications are taken twice a year and if more applications are received than the fund can allow, they are ranked on the basis of lowest cost per customer. Under BC Hydro's Uneconomic Fund, the utility sets aside $1.5 million per year to assist customers with their share of the customer contribution that would otherwise be required. The fund applies to individual customers only and is not available for new subdivisions. It therefore reaches those customers that are building individual homes in areas where distribution lines are nearby but not in front of the property. The customer is still required to pay a portion of the cost of the extension, however it is a sharing approach as opposed to the customer paying all costs above the allowed extension credit.

As put forward by EES, *"The underlying theory behind amalgamation is that all customers should be treated equally regardless of location."*[66] By providing the Fund, the Company believes that customers who are further away from our system or, those in less densely populated areas will be able to have more equitable access to natural gas service, consistent with the theory of amalgamation.

4.3.2 System Extension Fund Recommendations

FEI is proposing that the Fund be established for its natural gas customers at $1.0 million, equivalent to two thirds the size of BC Hydro's $1.5 million level, to reflect that FEI has a smaller service territory and a smaller number of new customer added annually. This will help alleviate the barrier of CIAC for some customers, and provide greater consistency with the common rate approach for FEI's service area. The fund will be recovered through gas delivery rates and will be accounted for as an offset to the CIAC additions included in rate base each year, based on the actual funding that is provided.

The Fund would be set up with comparable provisions to the BC Hydro fund; however, there would be natural differences due to the fact that it would apply to gas customers rather than electric customers. FEI is also proposing a simpler approach than the one in place at BC Hydro.

The following provides a summary of the proposed mechanism and terms for the FEI System Extension Fund.

[66] EES Report, Appendix A, p.7.

Eligibility

Funding would be available to the owner of a single-family residential home or townhome that is a principal residence within an existing FEI service area at the time the application is taken. Multi-property developments will not be eligible, as it is targeting home owners rather than builders. Eligibility would be the same as for FEI's contributory main criteria, except that customers would not be eligible for both the Fund and a contributory main refund. FEI will provide information about applying for the Fund to customers that meet the criteria but meet a minimum P.I. ratio of 0.2 resulting from the MX Test.

Total Funding Amount

The amount funded each year will be capped at $1.0 million. FEI will accept customer requests at the end of the first and second quarters of each year in order to ensure enough time is available for planning and scheduling before the fall and early winter months which are traditionally the busiest times for new customer connections at FEI. Half of the Fund will be reserved for each deadline; however, if there are unused funds available from the first deadline, the unused funds will roll over into the amount available for the second deadline. No funds will roll over from one year to the next.

Deadlines

Customers applying for service failing to meet the required P.I. of 0.8, but at least a 0.2, for the requested main extension can apply for the Fund. Customers must complete all required forms and submit them to FEI on or before March 31st or June 30th of each year. Forms will be available on-line as well as through regional FEI sales staff.

FEI will review all applications and will select projects to be funded. Project selection will consider the potential to connect future customers. Projects with a higher potential for future customer connections based on the number of lots between the customer and the beginning of the main extension will be given priority.

Customers will be notified of the results within two weeks of the deadline and will have an additional two weeks to commit to the extension. If customers decline to proceed, any funds that are freed up will be used to fund the next highest customers on the list. If the customer chooses, they can elect to have their application automatically rolled over to the next application deadline if their project is not funded.

The extension projects may not commence until funding has been approved and payment processed. Projects must commence within 9 months of the commitment date to retain their funding without re-submission. Further payment details will be determined at a later date.

Funding per Customer

Costs for the extension will be shared among the customer and FEI's other customers based on the following calculations for those that qualify for the uneconomic fund:

The customer would pay 50% of the CIAC of the project. The total amount paid by the Fund would be capped at $10,000 per customer. Given that the average contribution for refundable mains over the past few years has been approximately $5,000, a $10,000 limit will allow for a fair consideration of outliers.

Other Terms

Customers funded under this program will not be eligible for contributory main refunds.

Accounting Treatment and Rate Recovery

As noted above, the Company regards the $1.0 million as an annual maximum amount that does not accumulate. That is, unused fund amounts from previous years will not be carried over to future years. As such, FEI proposes to account for any allowance for customers from this fund as an offset to the CIAC additions that are included in rate base each year. As a result, these amounts will be recovered through the delivery rates of all non-bypass customers via the amortization of contributions embedded in the revenue requirement. This approach is simple, and is consistent with BC Hydro.

Illustrative Example

The Company has recently been examining the potential to extend natural gas service to customers within a community outside Penticton where a number of potential customers are looking to convert to natural gas. The MX Test results indicate a CIAC of approximately $5,000 per customer, assuming a significant number of natural gas appliances for each customer. $5,000 is prohibitive for many residents in this area so it has been challenging to marshal enough interest to reach a ‘critical mass’ for the project to proceed.

With the availability of the Fund, these residents could apply for up to $2,500 per customer, (i.e. 50% of the CIAC). In exchange for the $2,500, the residents would forgo the option to get a contributory main refund in the future in the event additional customers attached to the main. The Company believes that by simply having the Fund as an option, more residents will be likely to commit to the project earlier, thereby lowering the CIAC and the need to access the Fund.

Rate Impact Analysis

The introduction of the Fund will have only a very modest impact on existing customers, even under conservative assumptions. Using the Rate Impact analysis, the rate impact is conservatively forecast to be $0.001/GJ. This assumes the Fund is fully subscribed annually. This forecast does not take into account that by simply having the Fund as an option, more residents should commit to the main extension project earlier, thereby lowering the CIAC and the need to access the Fund.

4.4 *MX REPORTING*

MX reporting, and the rationale for improving the current reporting regime to facilitate more efficient reporting, has been discussed at length in various sections of the Application. Below are the Company's recommendations for annual reporting. The adoption of these recommendations will ensure that annual filings retain the character of reporting on FEI's compliance with the MX Test, rather than expanding into an annual review of the performance of main extensions themselves and the parameters of the MX Test. As discussed in section 4.5, a separate periodic process, informed by the Rate Impact analysis , is better suited for evaluating the Test.

4.4.1 MX Test

FEI believes that the Commission can obtain evidence of FEI's compliance with the MX Test in a more efficient manner consistent with the Core Review recommendations. The following represents the Company's proposal for a simplified MX compliance reporting structure:

- Discontinue current MX reporting requirements, effective for the 2015 calendar year
- Report to the Commission at the end of Q1 for the preceding year's main extensions, including the following:
    - Updated MX Test input parameters consistent with current practices;
    - MX Test data as follows:
        - Total number of main extensions completed;
        - Total actual costs for all main extensions;
        - Forecast aggregate PI for all main extensions; and
        - Number of customers providing a CIAC & dollar value of CIAC.

4.4.2 Main Extensions with 10 Year Customer Forecast

The Company proposes including a summary of the 10 year customer addition forecast projects in the annual MX reporting. Specifically, the Company will provide the following:

- The number of main extensions using a 10 year customer addition forecast;
- The actual costs for the mains; and
- The number and dollar value of any CIAC provided by customers for the mains.

4.4.3 System Extension Fund

The Company proposes including the following data in the annual MX Report:

- The total number of approved requests to access the Fund; and

- The dollar value of the approved requests.

The Company believes that its MX reporting proposal is fair, thorough and consistent with the intention of annual reporting - to report on the Company's compliance with the MX Test. Acceptance of the recommendations will also clarify the use of the MX Test and of the MX Reporting.

4.5 MX POLICY EVALUATION

The current annual reporting has, over time, taken on the character of an annual review of the economics of main extensions in the MX Report, and ultimately an annual review of the MX Test itself. FEI respectfully submits that the purpose of compliance reporting should be confined to monitoring FEI's compliance with the MX Test, and that annual reviews of the system extension policies themselves are too frequent and inefficient.

FEI recommends that it provide the Rate Impact analysis at the time that the Company applies to the Commission for a review of its system extension policies. The Rate Impact analysis provides a "point in time" view of the impact that new customers have on the system.

4.6 CONSISTENCY WITH GUIDING PRINCIPLES

Below, the Company demonstrates that its recommendations included in Section 4.1 through 4.5 above are consistent with the five Guiding Principles developed with stakeholders.

4.6.1 Provide Energy Choice

This Guiding Principle is intended to allow new customers increased ability to more easily access natural gas should they choose to do so.

The recommended changes to the SLCA and MX Test collectively meet this principle. For example, as discussed earlier, increasing the DCF term to 40 years increases the revenue in the MX Test by 41 to 47 percent and consequently, only 4.8% of customers over the 2008 to 2014 period would have been required to contribute to a main extension, as compared to 10% that did under the Company's existing policies. Another example is increasing the SLCA from $1,535 to $2,150 which will make it easier for new customers to access natural gas should they choose to do so.

4.6.2 Protect Existing Customers

This Guiding Principle is intended to ensure that the interests of new and existing customers are protected when considering changes to system extension policies. The Rate Impact analysis indicates that existing customers have benefitted from system extensions as demonstrated by the fact that rates have been lower by over $10 per customer or $0.058/GJ as a result of system extensions. Based on the analysis performed, the proposed updates will continue to provide balance between new and existing customers, since a conservative estimate of the rate impact of the proposed recommendations is an increase of $0.003/GJ, which is less than the existing benefit of $0.058/GJ.

4.6.3 Support Government Objectives

The Company believes the recommendations will support the provincial government by expanding access to natural gas service in order to achieve the following two objectives:

1. Providing the public the potential benefits of access to low cost energy, local economic development, the creation and retention of jobs and tax revenue, as described in the *Provide an Energy Choice* section
2. Assisting in meeting the legislated greenhouse gas (GHG) emissions targets and related Clean Energy Act (CEA) objectives.

For example, by updating the MX Test, SLCA and introducing the Fund, it will be easier to encourage higher carbon customers on Vancouver Island and elsewhere to convert to natural gas, which will result in lower GHGs, all else equal.

4.6.4 Recognize First Nations

It is expected the changes to the MX Test, SLCA and introduction of the Fund will make it easier for First Nations to access natural gas service should they choose to do so. For example, one of the stakeholders in the Review, Seabird Island Band, will have much greater opportunity to access service as a result of the changes put forward by the Company.

4.6.5 Easy to Understand

The changes recommended by FEI are easily understood, easy to administer by FEI, and stable over time for customers. One of the advantages to continuing with the MX Test and SLCA is that they have been in place for a number of years and continuing with the MX Test, updated as proposed, will continue to address both the simplicity of understanding as well as providing stability in extension policies over time. For example, the MX reporting and evaluation recommendations make it easier to understand and the expected reduction in the administrative burden related to MX reporting will make it much easier to administer. The changes recommended are expected to allow customers to enjoy the economic benefits of the MX Test over a longer time period, thereby creating stability in system extension policy.

4.7 *SUMMARY OF RECOMMENDATIONS*

Overall, the adoption of the Company's recommendations regarding the MX Test, the SLCA, the creation of a system extension fund, and improved MX reporting will result in a fair consideration of the interests of new and existing customers and more meaningful and efficient reporting.

5. RESPONSE TO COMMISSION LETTERS L-34-14 AND L-44-14

In Letters L-34-14 and L-44-14, the Commission encouraged the Company to complete its system extension policy consultation with stakeholders and Commission staff to address a number of system extension policy related concerns including providing a new reporting and evaluation methodology, and file an Application by the end of the first quarter of 2015[67]. The following section summarizes how the Company has addressed the Commission's requests relating to stakeholder consultation, forecasting accuracy, potential exposure to an undue cost burden and the inclusion of a proposal for a new MX reporting and evaluation methodology. FEI submits that it has properly applied the MX Test. The Commission's concerns about the performance of past main extensions are, to a significant extent, a product of shortcomings in the methodology being used by the Commission in its evaluation, the inputs being used, and incorrect inferences about the results. The proposed Rate Impact assessment is reasonable and fit for purpose and demonstrates that existing customers have benefited from past extensions.

5.1 *COMMISSION LETTERS*

Letter L-34-14 issued June 19, 2014, provided details of the Commission's concerns:

> *"The Commission is concerned that the 2008 aggregate PI results over the five year period were below 1.0, indicating that existing ratepayers might be exposed to an undue cost burden as a result of the expansion of the distribution system to attach these new customers…."*
>
> *"The Commission has identified two areas of concern it believes are contributing to the gap between forecast PIs and actual PIs over this period. These are:*
>
> *1) forecasting accuracy, and*
>
> *2) security and existing ratepayer protection in the event that costs, attachments and/or consumption do not materialize according to forecast estimates."*
>
> *"It is possible, had the Companies obtained sufficient contributions in aid of construction or other securities for main extensions where the actual costs were higher, attachments were fewer or later, and/or customer consumption was lower than forecasted, the potential exposure to existing ratepayers of an undue cost burden as a result of the expansion of the distribution system to attach new customers would have been mitigated."*

The Commission's expectations for the Application were expressed in Letter L-44-14, issued August 22, 2014:

[67] This deadline was extended to June 30 as per Commission Letter L-6-15

"The Commission expects the Companies to continue working with stakeholders and Commission staff to develop and review a detailed terms of reference, addresses the concerns raised by Commission in Letter L-34-14, and file an application for revised main extension policies in the first quarter of 2015. The concerns raised by the Commission in Letter L-34-14 include but are not limited to: 1) the forecasting accuracy of main extension costs, number of attachments, timing of attachments and use per customer, and 2) the application of efficiency credits, contributions in aid of construction, and security deposits."

Finally, Letter Log No. 47342,[68] summarized the Commission's most recent expectations regarding MX reporting and evaluation:

"The Commission looks forward to receiving the proposal for a new reporting methodology for evaluating the success of a main extension as part of a System Extension Policy Review Application to be filed by June 30, 2015."

Before addressing the Commission's concerns in detail, there are several notable factors about the Commission's commentary worth highlighting:

- First, with respect to the Commission's statement that "The Commission is concerned that the 2008 aggregate PI results over the five year period were below 1.0…", it should be noted that the PI on a forecast basis has exceeded 1.0 in aggregate. It is only when the Commission re-ran the MX Test after the fact with updated costs and forecasts did it reach that conclusion. FEI has been applying the MX Test appropriately as a prospective test.
- Second, the Commission's reference to "actual PIs" in identifying "the gap between forecast PIs and actual PIs over this period" is a misnomer. The Commission's analysis is based on re-running the MX Test with actual costs, but only an updated forecast of revenues. The "actual PI" is not synonymous with cost effectiveness, nor is it reflective of the impact on existing ratepayers.
- Third, while the Commission references *"forecasting accuracy"* and *"security and existing ratepayer protection in the event that costs, attachments and/or consumption do not materialize according to forecast estimates"* affecting the gap, other factors that are influencing the results of the Commission's analysis include the assumptions that the Commission is using in the re-run forecasts.

[68] Dated June 4, 2015, acknowledging receipt of the FEI 2014 Main Extension and Vertical Subdivision Report

5.2 SUCCESSFUL STAKEHOLDER CONSULTATION

Letter L-44-14, issued August 22, 2014, requested that FEI work with Commission staff and stakeholders to "develop and review a detailed terms of reference that address the Commission's concerns…" In Stakeholder sessions 1 and 2, that had been held on February 18 and June 18 2014 respectively, FEI and stakeholders, including Commission staff, had already developed Terms of Reference, which are attached as Appendix B-5 After receiving Letter L-44-14, FEI reviewed the TOR as well as the content of first two workshops and the plan for the final two stakeholder workshops to determine if Commission requests were being addressed. Table 3-2 Stakeholder Review Summary, outlines the topics for each of the four stakeholder sessions.

FEI confirms that it has met the Commission's request to develop a TOR that meets the Commission's concerns. FEI was able to engage in a dialogue with a variety of stakeholders and provide a venue to educate participants on the issues and to develop the five Guiding Principles (described in more detail in Section 3) which have served as a guide in developing the Company's recommendations in the Application. A description of how the recommendations in this Application are consistent with the Guidelines is also included in Section 4.

5.3 RATE PAYERS NOT EXPOSED TO UNDUE COST BURDEN

As referenced above in Letter L-34-14, the Commission expressed concerns that rate payers "might be exposed to an undue cost burden as a result of the expansion of the distribution system to attach these new customers…" The Commission appears to have drawn the conclusion that existing customers may have been exposed to undue cost burden based upon the results of re-running the MX tests, since the re-run PI's are lower than the original forecast PI's. FEI submits that the method by which the Commission undertook its assessment could not have provided the necessary information to determine the cost-effectiveness of main extensions or provide a sound basis to speculate whether or not customers will be exposed to an undue cost burden.

As noted in the 2014 MX Report and in Section 3 of this Application, the MX Test was not intended to be used to evaluate the cost effectiveness of a main extension ex post. It is a forecast planning tool to determine if a customer should be connected to the system and if that customer is required to pay a contribution to do so. The purpose of FEI's MX compliance reporting provided to the Commission is to ensure that the Company is applying the MX Test correctly *prior to installation*. Specifically, the Company has demonstrated it has used the relevant parameters and, consistent with Order G-152-07, individual mains have a PI greater than or equal to 0.8 and the portfolio is greater than or equal to 1.1.

As part of the MX Reports, the Company re-runs the forecast PI as requested and designed by Commission staff, but FEI has always considered the results of the re-run analysis to be misleading if they are used to assess the economics of past extensions or ratepayer impact.

An assessment of the cost effectiveness of a main should logically account for the at least a majority of the economic life of the main. In the MX Report, the MX Tests are re-run in years 1-5 of the life of a 50+ year main. As noted in Section 3, while some inputs in the re-run MX Test are actuals, others are reforecast according to Commission staff requests. The revenue forecasts are being re-done as little as one year after the extension, or less than 1/50th into the service life of the asset. Some of the assumptions prescribed by the Commission for the re-run test skew the results of the comparison. Thus, the PI resulting from this re-run test can be expected to differ from the original forecast PI, and the variances may have little relationship to the economics of the extension or ratepayer impact.

As noted in Section 3, EES, with support from FEI, developed the Rate Impact analysis to understand if extensions have had a positive or negative impact on rates in the 2008-14 period. The analysis suggests that customer rates have been lower (other things being equal) as a result of historical system extensions, meaning that existing customers have benefitted from system extensions that occurred from 2008 to 2014. The Rate Impact analysis also suggests that if there are rate impacts associated with updates to the MX Test to address the addition of new customers, they could be borne by existing customers, thereby achieving better balance between the two customer groups.

5.4 *FORECASTS ARE REASONABLE*

The Commission noted that they had concerns regarding "*the forecasting accuracy of main extension costs, number of attachments, timing of attachments and use per customer*".

Overall, FEI believes its approach to forecasting is appropriate and reasonable. Some forecast variances are to be expected, and the size of variances has differed. FEI has implemented a number of additional checks and balances in recent years to increase the accuracy of its forecast.

5.4.1 Main Extension Costs

As seen in Table 5-1 below, the historical average cost variance is 9.5%.

Table 5-1: Historical MX Reporting Cost Variance

	Forecast Cost	Actual Cost	Variance	Variance (%)	Comments
2008 FEI	$ 891,766	$ 970,334	$ 78,568	8.8%	MX reporting complete
2008 FEVI	$ 546,720	$ 640,757	$ 94,037	17.2%	
2009 FEI	$ 2,093,186	$ 2,496,469	$ 403,283	19.3%	Year 5 of cost reporting
2009 FEVI	$ 1,336,265	$ 1,614,962	$ 278,697	20.9%	
2010 FEI	$ 883,607	$ 1,022,727	$ 139,120	15.7%	Year 4 of cost reporting
2010 FEVI	$ 829,198	$ 821,133	$ (8,065)	-1.0%	
2011 FEI	$ 1,475,371	$ 1,613,483	$ 138,112	9.4%	Year 3 of cost reporting
2011 FEVI	$ 859,365	$ 871,582	$ 12,217	1.4%	
2012 FEI	$ 1,166,451	$ 1,683,333	$ 516,882	44.3%	Year 2 of cost reporting
2012 FEVI	$ 568,885	$ 558,529	$ (10,356)	-1.8%	
2013 FEI	$ 635,791	$ 549,965	$ (85,826)	-13.5%	Year 1 of cost reporting
2013 FEVI	$ 614,218	$ 570,460	$ (43,758)	-7.1%	
			Average Variance	**9.5%**	

It is important to consider the cost variance within the context of the number of attachments. For example, the 2012 FEI cost variance is 44.3% which appears to be an unfavorable outcome. However, as will be shown in the Number and Timing of Attachments section that follows, the 2012 FEI attachment variance was 38%. In other words, the Company added more customers than forecast therefore the costs are higher than forecast. So, the cost variance in fact reflects the *favorable* variance in customer attachments.

The Company completed approximately 5,500 main extensions from 2008 to 2014. The terrain and circumstances for the extensions can vary significantly and are often unpredictable despite the Company's expertise at estimating costs. Due to unforeseen circumstances such as rocky conditions, inclement weather, environmental considerations, conflicts with foreign utilities and other encumbrances, a variance between the forecast and actual costs, such as those seen in the table above, is to be expected.

FEI has implemented a number of additional steps in recent years to increase the accuracy of its forecast and the Company continues to refine its approach to cost estimating, including weighing the potential benefit of forecasting accuracy against the additional costs of providing more detailed estimates themselves.

As will be seen below, the Company has taken a balanced approach in recent years by using manually intensive estimates for more complex projects versus pricing averages for those projects that are simpler.

For projects with special characteristics such as a bridge or water crossing, larger size main, or higher pressure requirements, the Company implemented a new manual estimate process starting in 2010. The Company introduced this change to help improve the forecasting accuracy for more complicated main extensions. For the small percentage of main extensions (approximately 10%) where manual estimating is determined to be appropriate, the person responsible for developing the cost estimate of the project (the Planner) uses information contained in the construction services contract with the Company's service provider. In other words, the Planner uses the same criteria for cost projections as those actually performing the construction of these projects. As seen in the Table above, since this change was implemented in 2010, the cost variance has improved.

The Company also employs Geo Code pricing[69] which allows for efficiencies in price estimating in light of the significant number of extensions that are estimated each year. The use of a manual estimate approach in conjunction with Geo-Code prices has helped to minimize the variances between forecasted and actual service line costs over time. Further it has allowed FEI to manage internal costs when providing estimates. Below is an excerpt from the 2014 MX Report showing the Geo Codes and Manual Estimate parameters used to develop main extension capital cost estimates in the MX Test in 2014. For example, in Vancouver and Squamish, for a PE pipe up to 60 mm, the Geo Code price per meter is $56. A forecast cost for a hypothetical, relatively simple 100 meter main extension in this area would be $5,600 plus the cost of the service line (s) and meter (s). $5,600 is then inputted into the MX Test along with all the other relevant parameters to determine if a CIAC is required.

Table 5-2: Geo Code & Manual Estimate Parameters

	Geo Code & Manual Pricing ($/metre)						
		PE Pipe ($/m)			Steel Pipe ($/m)		
	Zone	Up to 60 mm	88 - 114 mm	168 mm	Up to 60 mm	88 - 114 mm	168 mm
2014	Vancouver & Richmond	$56	Manual Estimates Only				
	North Shore & Squamish	$61					
	North of Fraser River	$53					
	South of Fraser River	$44					
	Interior North	$34					
	Interior South	$34					
	Vancouver Island	$50					

Another check and balance implemented is graduated senior management oversight. As main forecast costs increase, additional approvals from more senior staff are required.

Lastly, FEI has been looking for efficiencies in its mains and services work to reduce overall costs of installation.

[69] Geo is short for geographical. Geo Code prices are derived by running regression analysis on historical data to derive average dollar per meter estimates. The Company has seven geo code zones

The Company believes that forecasting accuracy with regards to the cost of a project is reasonable and that its approach to costing using geo-pricing or manual estimates for special circumstances should continue. This method provides an appropriate measure of per meter costs and will continue to be updated on an annual basis.

The cost variance is reasonable and has been steadily improving since 2010. FEI's expectation is that, with these measures in place, and an on-going commitment to improving the processes, the forecasts will continue to be robust, acknowledging however that there will still be variances related to factors beyond FEI's control.

5.4.2 Number and Timing of Attachments

As seen in Table 5-3 below, the historical average variance between the forecast and actual number and timing of attachments is reasonable at 7.2%.

Table 5-3: Historical MX Reporting Attachment Variance

	Forecast Attachments	Actual Attachments	Variance	Variance (%)	Comments
2008 FEI	571	417	-154	-27.0%	MX reporting complete
2008 FEVI	293	259	-34	-11.6%	
2009 FEI	1228	1061	-167	-13.6%	Year 5 of attachment reporting
2009 FEVI	698	430	-268	-38.4%	
2010 FEI	478	442	-36	-7.5%	Year 4 of attachment reporting
2010 FEVI	402	262	-140	-34.8%	
2011 FEI	715	696	-19	-2.7%	Year 3 of attachment reporting
2011 FEVI	291	226	-65	-22.3%	
2012 FEI	620	853	233	37.6%	Year 2 of attachment reporting
2012 FEVI	166	173	7	4.2%	
2013 FEI	516	641	125	24.2%	Year 1 of attachment reporting
2013 FEVI	232	244	12	5.2%	
			Average Variance	**-7.2%**	

As seen above, the variance has been improving over time. For example, in 2008, FEI's variance was 27% below forecast whereas in 2013, the Company is 24% above forecast.

5.4.2.1 Market Conditions Affect Results

The variance above is a function of the market conditions at the time. For example, the global financial crisis in 2008/09 had a significant, negative impact on the B.C. new construction marketplace resulting in delayed attachments for FEI. However, more recently the variance is favorable. Regardless of the market conditions, the Company has a robust process in place to ensure the attachment forecasts are reasonable.

The Company forecasts attachments based upon discussions with developers and its own knowledge of the marketplace and history with the developer. FEI's sales staff spend significant time working with developers to determine not only the number of attachments but the timing. As was demonstrated in the second stakeholder workshop, developments start with bare land which is then filled with houses over time. If a developer is planning "X" number of houses being built, in most cases that is what is built. Timing however is much more difficult to forecast. It is in the developers best interest to build and sell the house as quickly as possible as the longer it takes to build and sell the lower the margin for the developer. FEI's staff work with developers to determine a likely timeframe for the completion and attachment of the building. However, some events outside the control of the Company, can delay the build of projects.

FEI recognizes that it is not only the market that can affect the accuracy of information provided by the developer. In recent years the Company has also changed the approval process for customer attachments such as a graduated approval is required based on the size of the project. Specifically, for smaller main extensions, a sales manager would sign off on all customer attachments and consumption while the Planner would sign off on the forecast cost. Together, both Sales and Planning/Operations must approve the MX Test results before the project can proceed, including the forecast PI, any CIAC as well as any steps being taken to collect security such as a take or pay agreement. For larger projects, approvals progress from the manager level to more senior management levels depending on the size of the project. This senior management oversight provides an additional opportunity to critically assess the information obtained from developers.

Overall, FEI's approach to forecasting attachments is appropriate and our variance results are reasonable.

5.4.2.2 Distortion Associated with Design of Commission's Assessment

The design of the Commission's current assessment approach distorts the results because it deems attachments after year 5 not to have occurred. As noted in the 2014 Report, if actual and expected attachments are used rather than a reforecast using Commission requested changes to the forecast, the picture can look quite different. The variances in 2008 that formed the basis of the Commission's comments are a good example of this.

Due to the 2008 recession, attachments forecast in 2008 came on later than forecast, and many occurred just outside the five year window considered by the existing reporting construct. If a sixth year is included, the results change. For example, in 2014 for FEI and FEVI there were 50 and 14 respective attachments that could not be included in the 2014 MX Report as a result of the reporting structure. Therefore, based on the 2008 aggregate main extension sample, by year 6 FEI has achieved 467 out of 571 forecasted attachments or 82%. FEVI has achieved 273 out of 293 forecasted attachments or 93%.

These results are summarized in the table below.

Table 5-4: MX Reporting Variance vs. Actual Variance

	MX Report Variance at the End of Year 5 (%)	Variance at the End of Year 6(%)
FEI	27%	18%
FEVI	12%	7%

This finding reinforces the position of the Company that the reporting constructs are generating misleading results and should not continue to be used to assess the economics of installed extensions.

Since main extensions can continue to add attachments each year throughout their life, FEI submits that the attachment forecast performance is reasonable. The Company will continue to forecast customer attachments based on plans submitted by the builder/developer or homeowner and build and design main extensions accordingly. The Company also notes that in cases where there is uncertainty surrounding the number and timing of attachments the Company has the right under the Tariff to request security. Security is discussed further below in Section 5.6.

5.4.3 Use per Customer - Consumption Credits

As noted in Section 2.2.1.1.1 of the Application with respect to the way in which consumption per customer is determined for the Test, the volume associated with a customer attachment within the Test is not a forecast of what new customers are expected to consume, as the Commission has been erroneously assuming in the re-run Test. In contrast to both the forecast of costs and attachments, volume is a *credit input* to the Test (similar to other inputs such as O&M and SI charge). It is intended to credit the new customers with an amount of consumption equal to the average consumption of other existing customers on a per appliance basis in order to treat the two groups comparably. The current MX reporting methodology is flawed as it incorrectly compares a consumption credit based on existing customers to the actual consumption of a new customer(s). This flaw has led to a misinterpretation of the data provided in the MX reports. As a part of the Application, the Company is proposing to discontinue the current practice of comparing a consumption credit to actual consumption.

Consumption credits in the MX Test are determined by assigning a consumption value in GJs per year for each appliance the customer installs. The annual consumption per appliance is taken from the Residential End Use Study (REUS). The MX Test has been updated with REUS values in 2002, 2008 and 2012; this methodology was acknowledged in BCUC Order G-152-07.

The REUS contains a cross section of all users on the FEI natural gas distribution system. As such, the values will not reconcile to the MX Report which contains the actual consumption of the newest most energy efficient customers. However, as these energy efficient customers come on to the system in larger and more frequent numbers, the existing system averages will be reduced. This in turn will be reflected in subsequent residential end use studies.

In general the average appliance consumption from the REUS provides a credit for the revenue portion of the System Extension Test which directly impacts the Test result and ultimately how much a customer will have to pay to connect to the system. This credit value is a fair reflection of what other customers would have been granted at the time of their connection. At the time of forecast, the expected annual consumption values derived by the Company are accurate in that they are reflective of the existing customer base and are an effective approach to ensure all customers are treated equally.

In order to arrive at the number of appliances in each home, the Company works with the developer to encourage the developer to use gas for heating and comfort. These appliances are put into the Test and are automatically given the appropriate volume (based upon the REUS of existing customers) which is used to derive revenue.

FEI's history with developers shows that the Company is able to accurately estimate the number of appliances. However, FEI cannot control the use of appliances once installed in the home. The individual consumption pattern of each customer attaching to a particular main extension contributes greatly to the variance between the forecast and actual consumption of a main extension. FEI has seen an overall reduction in use per customer for new customers compared to existing customers. There are several factors which may contribute to the reduction in use per customer more generally, including successful energy efficiency and conservation efforts, marketplace shifts to high efficiency appliances, and a reluctance of customers to incur the high fixed costs associated with installing multiple gas appliances. As technology continues to evolve, EEC programs expand and building codes reflect more energy efficiency, the Company expects that these factors will continue to impact new customer consumption levels.

With respect to those customers that have installed high efficiency appliances, the Company does not feel it would be appropriate to encourage the customer to consume more gas simply to meet the volume averages of existing customers in order to create a more favourable MX Test result. Nor would it be fair to new customers to use a lower volume for a more efficient appliance as a credit in the test as this would lead to a lower PI forecast and encourage customers to use less efficient appliances in order to pass the MX Test. In addition, the Company does not have data on which to base a volume credit for gas usage in new more efficient appliances. Finally, in a main extension project where there is a mix of both residential and commercial customers, the actual consumption figures and use per customer are subject to significant variation from the forecast if just one of the larger commercial customers delays the attachment, given that the usage of a large business is generally much greater than several single family dwellings.

Therefore, as noted in Section 3, it remains appropriate to use the volume credit, as derived from existing customers in the REUS, as an input into the MX test. The Company believes that by continuing to adhere to previously approved methodologies and using an appliance consumption average, derived from the REUS for all existing customers, will ensure all customers are treated equally in the MX test regardless of when they connected to the system.

To support consistency and comparability, the Company proposes that the new main extension reporting contain only forecast consumption values for all new customers. This will avoid confusion in the interpretation of data.

5.4.4 Forecasting Summary

FEI's cost and attachment forecasts are reasonable and appropriate given the complexities of estimating projects across the Province in a cost effective manner and the challenges of estimating vagaries of the marketplace. The Company submits that it would be a mistake to assess the economics of past extensions based on the approach currently being used, as the results of such an analysis may be distorted by market conditions and shortcomings in the design of the current assessment approach. Volume is not a forecast but rather a credit in the test and is calculated in a reasonable manner. As has been demonstrated by the Rate Impact analysis, the addition of new customers over the 2008-2014 period has resulted in a positive rate impact to existing customers. Said another way, for new customers actual revenues are higher than actual costs and therefore it is in the best interest of existing customers to add new customers.

5.5 *APPLICATION OF ENERGY EFFICIENCY CREDITS*

The Company has applied the energy efficiency credits as approved by the Commission in Order G-152-07. In Section 4, the Company indicated that six percent of main extensions completed from 2008-2014 used the 10 percent credit and less than 1 percent used the 15 percent credit. The Company has proposed to remove the efficiency credits from the Test going forward to make the implementation of the Test simpler and easier to implement. The Company now has a robust Energy Efficiency and Conservation program that encourages customers to use gas more efficiently. As such the Company believes that it does not need to include these credits in the MX Test, in conjunction with the other proposed amendments to the MX Test.

5.6 *SECURITY AND CONTRIBUTION IN AID OF CONSTRUCTION*

The Commission stated:

> *"It is possible, had the Companies obtained sufficient contributions in aid of construction or other securities for main extensions where the actual costs were higher, …the potential exposure to existing ratepayers of an undue cost burden as a result of the expansion of the distribution system to attach new customers would have been mitigated."*

5.6.1 Sufficiency of Contributions

The Company is adhering to the terms of security and CIAC defined in our tariff, and FEI does not believe that changes to either approach will be beneficial to customers.

After inputting the forecast costs, forecast attachments and consumption credits, the MX Test is run. If the individual PI of the MX Test is below 0.8, a customer contribution is required in order to bring the PI up to 0.8. In the case of a service line, if the anticipated costs of the service line are forecast to exceed the SLCA, a CIAC is required. Section 4 highlighted that from 2008-2014, 551 out of 5,492 main extension projects required a CIAC, totalling approximately $3.9 million in value. The Company applies the CIAC consistent with sections 12.6-12.9 of its General Terms and Conditions. The CIAC cannot be arbitrarily increased by FEI.

As noted, the Company's view is that the addition of new customers under the current extension policies benefits existing customers. The CIAC is currently one of the larger barriers to customer attachments. If the CIAC was to increase, fewer customers would attach, resulting in a decreased benefit to existing customers as discussed.

5.6.2 Sufficiency of Security

Security is used in instances where the Company believes that there is a risk that the customer (typically a builder or developer) may not attach to the system in the timeframe expected, the number of appliances will not materialize or, in the case of commercial and industrial customers, when there is risk of the customer leaving the system. The Company adheres to section 12.10 of its tariff that stipulates, "*In those situations where the financial viability of a Main Extension is uncertain, FortisBC Energy may require a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy.*"

Security can provide a further level of ratepayer protection in the event a builder or developer did not deliver on their commitments. Most developers do not require any security as history has shown us that appliances are installed and customers do attach. Developers do have some control over what appliances are in the house/unit but do not control the end use customer's usage or the exact time frame that the end use customer connects to the gas. Where the builder or developer has provided reasonable forecasts of appliances and end use customers, it would then be inappropriate to require security due to ultimate usage not materializing as that is beyond their ultimate control. To do so would be a disincentive to consider natural gas in their building plans.

It should be noted that security is seen by developers and customers as a punitive measure. Rather than increasing existing rate payer protection because security is acquired, developers may choose not to attach, reducing the potential benefit from the addition of new customers to the system. As such, the use of security must be used judiciously.

The Company believes that it is applying security appropriately and in a manner that considers the risk of new customer attachments without creating a punitive signal to the market. Applying more stringent steps would likely result in fewer attachments and therefore less benefit to potential and existing customers.

5.7 NEW REPORTING METHODOLOGY PROVIDED

The Company has demonstrated in Section 3 that the existing reporting methodology should be changed to improve efficiency. FEI is proposing two changes.

The first change is providing simplified annual compliance reporting. The purpose of this reporting should be to ensure that the Company is applying the MX Test correctly *prior to installation*. The Company has demonstrated it has used the relevant parameters and, consistent with Order G-152-07, individual mains have a PI greater than or equal to 0.8 and the portfolio is greater than or equal to 1.1.

Second, the Company is proposing to perform the Rate Impact analysis at the time of future MX applications such as those performed in 1996, 2007 and 2015. The purpose of this analysis would be to assess the effectiveness of the Company's system extension policies. This analysis will generally be performed *ex-post* installation. Since the true impact of a main extension can only be measured once a material portion of the life of the main has passed, even the Rate Impact analysis has limitations in its usefulness. However, the Company believes this analysis is valid as it provides a practical means to guide the future assessments of our system extension policies and is free of some of the issues associated with re-running the MX Test.

5.8 SUMMARY

In summary, the Company believes it has addressed the Commission's requests in Letters L-34-14 and L-44-14. It has addressed the nature and function of MX reporting and evaluation and provided a recommendation for a revised reporting structure. FEI's proposals for the MX test are reasonable, and the reporting framework will allow efficient Commission oversight.

Appendix A

EES CONSULTING – FEU SYSTEM EXTENSION POLICY REVIEW REPORT

FortisBC Energy Inc.

FortisBC Energy Inc.
System Extension Policy Review

June 2015

Prepared by:

EES Consulting

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EES Consulting

June 30, 2015

Mr. Brent Graham
Manager, Energy Product & Services
FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8

SUBJECT: Mains Extension Policy Review

Dear Mr. Graham:

Please find attached the Review of FortisBC Energy, Inc's System Extension Policy report prepared by EES Consulting. The conclusions and recommendations contained within this report are based upon industry practice and generally accepted rate setting principles.

This study has been developed independently by EES Consulting, with information provided by FEI staff, as needed. The findings, conclusions and recommendations of this report provide support for the development of an alternative approach for determining the system extension allowances for new FEI customers.

Thank you for the opportunity to assist FEI in this rate setting process. Please contact me directly if there are any questions about the subject analyses.

Very truly yours,

Gary S. Saleba

Gary S. Saleba
President

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Contents

Executive Summary

Fortis Energy Inc. (FEI) retained EES Consulting to review and assist the utility in assessing its current System Extension policy to determine whether current policies meet standard practices and whether the existing customers remained unharmed as a result of system growth.

Specific tasks assigned to EES Consulting involved a review of practices by other utilities in Canada and the US and to determine whether or not existing ratepayers are being held harmless from the impacts associated with the costs of mains and service extensions for new customers. While the MX test is designed to ensure individual projects meet an economic test, a rate impact model was developed to quantify the actual impacts associated with growth that has occurred over the past several years. This provides a more global view of the impact to customers than the individual MX test calculations.

This report includes a look at the overall theory associated with setting extension policies, a summary of the survey of utilities conducted by EES Consulting, as well as information provided by other parties with respect to standard practices. The rate impact analysis is then provided to demonstrate the impacts on rates associated with the current extension policies, along with recommendations that result from the tasks assigned to EES Consulting.

Comparison with Standard Practice

As with most other utilities in Canada, FEI's extension policies are based on a discounted cash flow model showing the incremental costs and benefits associated with new customers. Some of the specific factors used within the cost benefit comparison are also aligned with standard practice, while others factors are not. In addition to those factors that may be inconsistent with other utilities, FEI recently underwent an amalgamation of the utilities which also needs to be considered when setting extension policies. For these reasons, FEI is proposing to make some changes to its extension policies. Details associated with the underlying theory behind extension policies and the survey of various utilities are included in subsequent sections of this report.

Another issue that was examined were recent trends in extension policies, in particular, how expansion to off system communities are treated. The growth of natural gas supply in North America has resulted in improved competitiveness in natural gas relative to alternative fuels. This has resulted in several states in the U.S. where government policy to promote the expansion of gas has led to changes in how main extensions are dealt with by the utilities. This trend has also expanded into Ontario, through the Natural Gas Access Loan and the Natural Gas Economic Development Grant programs recently announced.

Within B.C, there is a precedent from B.C. Hydro for funding certain projects that are otherwise considered uneconomic. Funding of uneconomic projects is allowed for by BC Hydro under its

Uneconomic Fund. This fund has been in place for roughly 30 year and currently is funded up to $1.5 million per year. This program is aimed at individual customer connections, typically in more rural areas, and does not apply to new housing developments. The Uneconomic Fund is a cost included in the annual revenue requirements of BC Hydro and is funded from customer rates.

Rate Impact Analysis

To determine whether FEI's current extension practices and customer growth have been beneficial or detrimental to existing customers, a rate impact analysis was designed to quantify the effects on existing customers. The rate impact analysis was designed to determine how the impacts of multiple years of growth impact overall rates. This approach can take into account whether the addition of capital costs from new customers is offset by the spreading of fixed costs over a higher amount of sales. The rate impact analysis attempts to model both the added costs and the added benefit of the additional sales to new customers.

The analysis measures the revenue requirements before and after customer additions. It also measures the annual sales or gas consumption (GJ's) before and after customer additions. These two measurements allow us to look at the average cost per GJ and determine if it has increased or decreased as a result of the new customers. Detailed results of the rate impact analysis are contained in a later section.

The results show that the sales associated with actual growth that occurred during a 7-year period more than offset the incremental costs associated with those added customers. Savings of 1.4% resulted from the analysis, representing a savings of $10.45 per customer per year due to the addition of new customers. When this amount is multiplied by the total number of customers on the system, the total annual impact is $10 million.

Given the magnitude of the savings indicated by the rate impact study, FEI could make significant changes in its extension policies without harming the existing customers.

Recommendations

Based on the utilities surveyed, FEI appears to be fairly consistent with the utilities in Canada in its use of the MX test and current P.I. targets. There are some specific changes that should be made to the MX test parameters to be consistent with standard practice and the specific circumstances for FEI, as follows:

- The timeline for revenue within the MX test should be expanded from 20 years to 40 years to be consistent with standard practice and the life of the assets.
- FEI should consider changing the attachment window from 5 years to 10 years in some cases.
- The 23% overhead adder should be changed to reflect a sliding scale or cap on the total amount for a given project.

The annual reporting requirements for actual costs and revenues for main extensions are also inconsistent with standard practice in the industry, as most utilities are not required to submit detailed after the fact reporting. If reporting is to continue, it should look at the overall impact on customer rates rather than the current complex reporting structure in place.

Given that the analysis shows that existing customers are benefitting by $10 million per year due to the addition of new customers on the system, there is ample room to make these changes to the MX test without increasing rates for existing ratepayers.

Based on the analysis, there is also adequate savings in rates due to new customers to accommodate the establishment of a $1 million per year fund comparable to the Uneconomic Fund offered by BC Hydro. This would provide a tool to lessen the burden on those individual homes that currently would be required to pay a large CIAC, provide a level playing field with BC Hydro, and allow for extensions that could be built upon and serve additional customers in the future in an economic fashion.

Finally, off system communities provide a more difficult challenge. There are no government studies/mandates within B.C. to promote the expansion of natural gas in the Province and therefore FEI is not proposing to expand natural gas into off system communities that do not meet the MX test provisions at this time, however, serving those off system communities may be appropriate to consider in the future. Monitoring activities in Ontario will be important as this may provide some guidelines for the future in B.C.

Introduction and Objectives

EES Consulting was retained by FEI to review and assist the utility in assessing its current System Extension policy. That work incorporates both a review of practices by other utilities as well as analysis related to the impacts of the current policy on existing customer rates. This work originated in 2012 and has been ongoing throughout the stakeholder process and application preparation. As such it has evolved during that time, with the final work presented in this report.

Objectives

FEI is proposing to make changes to various assumptions and policies related to the main extensions to ensure a balance between new and existing customers and reflect the stakeholder objective of promoting energy choice for customers. EES Consulting was retained to provide input on whether it would be appropriate to make the proposed changes to the MX test and associated policies in terms of both consistency with standard practice and without placing an undue burden on existing customers.

The first task assigned to EES Consulting involved a review of practices by other utilities in Canada and the US to determine whether the practices of FEI are in keeping with standard practice and trends in the industry. A survey was conducted of the Canadian gas utilities as well as US utilities on the west coast, with the findings presented to FEI in a report in March 2013. More recent studies conducted by other parties were also examined in terms of standard practices and trends for utilities.

The second task was to determine whether or not existing ratepayers are being held harmless from the impacts associated with the costs of mains and service extensions for new customers. While the MX test is designed to ensure individual projects meet an economic test, a rate impact model was developed to quantify the actual impacts associated with growth that has occurred over the past several years. This provides a more global view of the impact to customers than the individual MX test calculations.

Because the Application itself discusses the background, the regulatory process and the proposed changes requested by the utility, those discussion are not repeated here. This report focuses only on the tasks assigned to EES Consulting.

Report Organization

To better understand the approach to extension policies used by FEI and others, this report first looks at the overall theory associated with setting extension policies. The next section provides a summary of the survey of utilities conducted by EES Consulting, as well as information provided by other parties with respect to standard practices.

The rate impact analysis is then provided to demonstrate the impacts on rates associated with the current extension policies. Finally, recommendations are provided that result from the tasks assigned to EES Consulting.

Theory Related to Extension Policies

To better understand how the extension policies of FEI comport with standard practice and how they impact both existing and new customers of the utility, it is important to understand the theory associated with extensions. These theories have been well explained in a report titled "Line Extensions for Natural Gas: Regulatory Considerations" prepared by the National Regulatory Research Institute in February of 2013[1]. That report is attached as Attachment 1. This section will highlight and summarize some of the key theoretical considerations and discuss how they relate to FEI's existing and proposed policies.

There are both costs and benefits associated with adding customers to the system, which is discussed first. As FEI recently underwent an amalgamation process for its various utilities, it is important to understand how both the theory and the results of amalgamation impact the examination of extension policies. Finally, three theoretical areas of interest discussed in the NRRI report are summarized and include the incremental vs. rolled-in approach for extensions, economies of scope resulting from new customers, and the evaluation of benefits associated with new customers.

Identification of Costs and Benefits

To understand how growth on the system through the addition of new customers impacts the utility, both costs and benefits are typically examined. A cost benefit approach is the underlying methodology associated with the MX test used by FEI. While new customers cause the utility to incur added capital and O&M costs, they also help pay for the fixed capital and O&M costs associated with operating the utility.

On the cost side there are capital costs associated with meters, services and any necessary main extensions to connect a customer. Added annual expenses include meter reading, billing, O&M for the new facilities and any other incremental costs. These costs are offset by the revenues paid by the new customer. These are the costs and benefits to the utility and they are included in the MX test. The MX test is used to ensure that existing customers are not facing increased rates as a result of the addition of new customers. An incremental approach is used in the MX test, as explained below.

While in some cases the cost-benefit ratio (referred to as the profitability index or P.I. under FEI policies) is less than 1, in other cases it is above 1. While FEI uses a threshold P.I. of 0.8 for each individual project, it has a 1.1 target for the sum of all extensions. Using an overall target of 1.0 would reflect a case where existing customers are no worse off or better off as a result of

[1] Line Extensions for Natural Gas: Regulatory Considerations, Prepared by Ken Costello for the National Regulatory Research Institute, NRRI, Report No. 13-01, February 2013.

adding new customers. Using an overall target rate greater than 1.0 leads to benefits to existing customers. The benefits come in the form of reduced rates.

When the P.I. is greater than 1.0, the revenues exceed the costs of serving the new customers, leaving some amount of revenue available to help in paying for the fixed costs associated with the utility. To the extent that new customers pay for some of those fixed costs, existing customers pay less for the fixed costs, resulting in lower overall rates. This issue is can also be identified as economies of scope. The rate impact analysis discussed in a later section measures this phenomenon.

While the costs and benefits associated with new customers have been addressed in terms of utility impacts, there are other potential costs and benefits that are not measured by the MX test. While it may not impact the utility directly, it is important to consider the impact to the new customer and any societal costs and benefits that could occur as a result of growth. Again, this topic is addressed in greater detail below.

Theory of Amalgamation

In addition to the theoretical issues typically related to growth in customers and extension policies, FEI must also consider how the amalgamation of its utilities and rates impact its extension policies going forward.

The underlying theory behind amalgamation and postage stamping of rates is that all customers should be treated equally regardless of location. While this was true within each of FEI's separate utilities prior to amalgamation, it was not true between the utilities. Because there are underlying differences in the cost to serve each and every customer on the system (based on location, geography, density, size, etc.) amalgamation supports the theory that rates should be set on a postage stamp basis, with all customers paying the same regardless of specific costs. Further, the differences *between* the utilities and regions are no different than the differences *within* the utilities and regions.

With amalgamation, the treatment and rates for customers will be the same for all of FEI.[2] While the rates are being phased-in to a common rate, that process will not be complete until January 1, 2018. Because the MX test calculates revenues associated with new customers, the rates used to develop revenues will be based on the common rates and will no longer differ by utility. On the cost side, the standard costs included in the MX tests will no longer differ by region or utility, although site-specific costs will continue to be developed for each project. The usage estimated for each new customer will also be based on common usage rates rather than regional levels. The usage will still be based on the expected appliances to be installed. In addition, the SLCA will be calculated and applied on an amalgamated basis. These changes in

[2] With the exception of the Fort Nelson region.

the MX test have already been incorporated and are not being phased-in, as is the case for the common rates.

Given the goals and practices associated with amalgamation, looking at each separate MX project as needing to be cost-effective on an individual basis may not be appropriate as it does not reflect the goal of treating customers the same regardless of their individual location and costs. This is already reflected to some extent by allowing some projects to fall as low as a 0.8 P.I. as long as the total for the system remains at 1.1. With amalgamation, the overall target for FEI becomes the relevant factor.

Incremental vs Rolled-in Treatment

Treatment of costs associated with investment generally are treated as either rolled-in or incremental pricing. With rolled-in pricing, all costs are placed into rate base with no customer contributions and costs are shared among all customers. Under incremental pricing, the investments associated with the addition of new customers are charged directly to those customers, with the underlying presumption that growth should pay for growth. The current extension policies in place at FEI are based upon incremental pricing.

As explained by NRRI, "Regulators generally approve rolled-in pricing when a new investment stands to benefit all customers, or when demand by all customers creates the need to increase system capacity."[3] The report further explains that "in the context of gas-line extensions, a utility expands its lines strictly to accommodate new customers. Existing customers are not signaling to the utility that it should invest in new lines. They would not pay for the gas-line extensions at any price. Charging incremental rates in this example would be consistent with the cost-causality principle, which is a tenet of good utility pricing."[4]

The incremental pricing approach does not charge the full cost of connecting a new customer to the system. Rather, it looks at the costs associated with mains and services that are already in the standard rates, and charges the incremental costs above that amount to the customer in the form of a contribution in aid of construction (CIAC). The NRRI report also refers to this as a "hybrid" approach with the economic portion of new lines rolled in to rates and the non-economic portion of lines using the incremental approach and being charged directly to customers. The MX test projects the revenues from a new customer, subtracts the direct costs associated with the customer, and the remaining margin is available to pay towards the new extension without causing a rate increase to existing customers.

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[3] Line Extensions for Natural Gas: Regulatory Considerations, Prepared by Ken Costello for the National Regulatory Research Institute, NRRI, Report No. 13-01, February 2013, page 34.
[4] Line Extensions for Natural Gas: Regulatory Considerations, Prepared by Ken Costello for the National Regulatory Research Institute, NRRI, Report No. 13-01, February 2013, page 34.

EES Consulting agrees that this theory is appropriate and FEI is following this theory with its existing policies. New FEI customers are paying for the incremental cost associated with line and main extensions, with the incremental cost determined by the current SLCA and MX test. FEI is not proposing to change to a rolled-in pricing approach, however, some of the proposed changes are aimed at better calculating the incremental cost to new customers as defined by the MX test.

Economies of Scope

The next theory that is important to consider in looking at the impact of adding new customers to the system is economies of scope. The NRRI report states "By definition, economies of scope measure the difference between the sum of the cost for serving existing and new customers separately and serving them simultaneously. We assume that serving one group of customers is distinct from serving the other group. As long as the utility recovers from new customers sufficient revenues to cover the incremental costs, no burden falls on existing customers."

Serving a larger number of customers is generally less costly due to added efficiency on a per customer basis. This is true for any cost that has a fixed component to it. For example, with billing there is a fixed cost associated with billing software that can be spread among more customers when growth occurs, however, there is an added cost for postage for each new customer. For large physical assets that are primarily fixed, such as transmission and storage, incremental costs for new customers are zero when no new assets are required.

While the MX test is designed to reflect incremental pricing and economies of scope in a manner such that new customers are not facing a rate increase as a result of customer growth, the MX test is based on assumptions about the various inputs in the test and is designed to look forward for a particular customer or project. While the Commission has requested that actual data be looked at on a retrospective basis through the MX reporting process, that data is also limited and does not necessarily capture all of the factors that impact rates when new customers are added to the system.

While it is important that existing customers do not see rate increases as a result of customer growth, it is equally important that new customers do not pay more than their incremental costs. According to NRRI, "If instead the utility recovers more than incremental costs from new customers…new customers are cross-subsidizing existing customers."[5] Existing customers should not receive all of the benefits of efficiencies and economies of scope related to new customers, thereby lowering their rates as a result of new customer growth. It is important to strike the proper balance where both new and existing customers are paying their share of the costs they cause and neither group is cross-subsidizing the other group.

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[5] Line Extensions for Natural Gas: Regulatory Considerations, Prepared by Ken Costello for the National Regulatory Research Institute, NRRI, Report No. 13-01, February 2013, page 29.

This theory is consistent with various sections of the U.C.A., where it is stated that the Commission must consider "the interests of persons in British Columbia who receive or may receive service from the public utility"[6] when looking at various issues. The Commission is directed not just to consider the impact on existing customers, but the impact on those customers that may receive service from the utility in the future.

To view whether the current policies strike the appropriate balance between new and existing customers, EES Consulting proposed that FEI look at the actual rate impacts for the utility as a whole outside of the MX process. A rate impact analysis was developed and is discussed in greater detail in the next section.

Evaluation of Benefits

One further theoretical issue that needs to be considered when evaluating extension policies is the potential for benefits accruing to existing and future customers outside of the ratemaking process, as well as benefits to non-customers in the Province. A method to account for those potential benefits needs to be established. The NRRI report discusses public benefits such as a cleaner environment or economic development in terms of line extensions. They specifically state that "When benefits from line extensions extend beyond those received directly by fuel-switching customers …regulators should ask whether it is appropriate to spread the costs to all customers."[7]

The consideration of these public benefits is already a recognized approach when evaluating conservation expenditures. In the case of conservation, there are multiple tests that look at different perspectives when deciding on conservation investments. In addition to looking at the impacts on rates alone, the savings accruing to the customer are considered along with other societal benefits such as clean air.

For the standard main extension program for infill customers and new development adjacent to the current system, it is appropriate to acknowledge that there may be some societal benefits (or costs) that have an impact but are not quantified through the MX test. When FEI looks at the decision on whether or not to extend service to off system communities, these societal factors become a much more important consideration due to both the magnitude of the benefits and costs associated with the expansions.

While it may be difficult to quantify the societal benefits association with expansion to a new community, the recognition of such benefits can be accounted for by agreeing that some level of funding for such projects may be appropriate to share among all customers. Further, the

[6] U.C.A. Sections 44.1.8.d., Section 44.2.5.e and Section 46.3.3.

[7] Line Extensions for Natural Gas: Regulatory Considerations, Prepared by Ken Costello for the National Regulatory Research Institute, NRRI, Report No. 13-01, February 2013, page 35.

benefits may be examined as part of the process for selecting projects that are most worthy of funding, even if done on a qualitative basis rather than a pure quantitative analysis.

While FEI is not proposing funding for the expansion to off system communities at this time, the potential for savings to new customers and other societal benefits should be a consideration when looking at changes to the extension policies of the utility. If FEI does wish to provide funding for off system communities in the future, the impact of societal benefits will be a large factor that will need to be addressed.

Survey of Practices by Other Utilities

To determine whether the system extension policies and tests in use at FEI are still in keeping with those of other utilities, and to explore how other utilities may have dealt with some of the issues facing FEI, EES Consulting surveyed the practice of other natural gas utilities in Canada and the Western U.S. The published 2013 report of that survey is attached as Attachment 2 and was previously provided to the Commission.

Since that time, several additional studies were performed by other parties and were examined to expand and update the findings of the original survey. The NRRI report published in 2013, which is provided in Attachment 1, provides some information related to the tests used by other utilities across the U.S. A report titled "Connecting New Communities", prepared by Concentric Energy Advisors for the Canadian Gas Association, was published in 2014, and also provides some background on practices within the U.S. This report is attached as Attachment 3.

This section provides some of the key findings of the EES Report as well as the other two reports examined.

General Approach to Extension Tests

The incremental pricing approach is the standard method used for looking at the need for CIAC payments for new extensions. While there are differences in the actual tests used, all of the tests are attempting to quantify the benefits and costs associated with a new customer. FEI uses a discounted cash flow model and looks at the cost benefit ratio in determining the customer's share of extension costs. This is the most common approach across Canada and in Washington State. Other utilities in the U.S. look at costs and benefits but use an internal rate of return calculation to determine the amount owed by the customer. Still others look at just the revenues over a set number of years as a proxy for the full cost-benefit approach. Additional methods include allowing a set distance at no cost to the customer, or allowing a set credit for each appliance installed, as is the case in Oregon and California. These latter methods are based on an underlying cost-benefit analysis but are streamlined for the sake of simplicity.

These general approaches are different but are all attempting to measure the same incremental cost theory. Therefore, we consider the FEI approach to be in keeping with the methods used by other utilities in Canada and the U.S. We do not see any distinct advantages to the internal rate of return method or other approaches, although we would consider them all to be appropriate methods. There is no reason for FEI to change its overall cost-benefit approach at this time as the current approach provides a reasonable assessment of incremental cost analysis.

FEI has separate practices for new customers requiring just a service line and those that require a main extension. When a main extension is not needed, there is a service line cost allowance (SLCA) that is applicable. The SLCA amount is calculated using the MX test, however, assumptions are standardized to provide a fixed amount that can be applied for new service lines and meters without having to run the MX test for each new customer that connects to an existing main. When a main extension is required, both the cost of the service line and main are taken into account within the MX test.

Because the SLCA amount is calculated from the MX test, it also represents an incremental or hybrid pricing approach. The survey of utilities was designed to gather information related to the extension of mains and not specific to the allowance related to service lines alone and therefore does not provide the standard practice used for service lines alone. The NRRI report, however, discusses the common practice of applying a set amount of dollars or length of line for new customers. This approach is also consistent with that used in the Province by both BC Hydro and FortisBC for electric customers. Both of those utilities use a standard credit amount to determine whether new customers are required to pay a CIAC amount. For that reason, it is our opinion that FEI's practice of calculating the SLCA using the MX test and applying that allowance for new customers not requiring a main extension is consistent with standard practice in the industry and within the Province.

Specific Assumptions Within the MX Test

While the FEI MX test follows standard practice of using a discounted cash flow to determine the incremental revenues and costs for the new customer, the specific assumptions used within the MX test have an impact on the outcome of the test. Therefore we looked at specific practices of other utilities with respect to those inputs. The inputs fall into the following categories:

- Revenue Calculations
- Cost Calculations
- P.I. Targets

In addition, FEI was also interested in reporting practices, the form of the actual cost and credit applied to the customer, financing practices and treatment of off system communities. Each of the input categories as well as the other topics are discussed in the sections below.

Revenue Calculations

To determine the revenues for the cost-benefit analysis, the expected consumption per customer is multiplied by the current rate level. For residential customers, the utilities generally use some form of average usage that reflects appliance installation and/or the specific region. For residential gas use, utilities generally use standard numbers per appliance for their particular region as the basis for the usage per customer for each particular case. These estimates are typically based on the average use of existing customers differentiated by specific appliance. In a few cases, a total system average for the class is used for all customers regardless of appliances. These average use numbers are not intended to reflect the use of customers in the future but rather reflect the average usage of all customers on the system. That allows new customers to be treated equitably compared to existing customers.

FEI is consistent in this practice as it uses the results of the REUS survey of usage per appliance which is based on all customers on the system. Because the REUS is updated periodically, any trends in customer usage will be reflected in the calculations. It is also consistent with the practice of BC Hydro where the line extension credit is a flat amount based on the costs and benefits associated with a customer using a standard amount of electricity based on historic averages.

For commercial/industrial customers, the usage forecast is customized and reflects discussions with the potential customer about the installation. FEI is also consistent with the other utilities in this regard.

Usage per customer is multiplied by current rates as the starting point for revenue calculations in the cost-benefit analyses. In all cases, utilities assume there are no real increases in the rate levels included; however, they are adjusted for inflation. FEI also assumes that rates will remain the same in real terms and is therefore consistent with the utilities surveyed.

In nearly all cases, revenues for residential customers are calculated over a length of time of 30 to 40 years with revenues discounted to reflect the present value. Heritage Gas uses a 25-year period. Manitoba Gas and SaskEnergy both use 30 years, while AltaGas and Puget Sound Energy use 32 years. Union Gas and Enbridge use a 40-year period. According to Union Gas and Enbridge Gas Distribution (EGD) staff, the use of 40 years corresponds to the life of the assets. This compares to the FEI calculations that use a 20-year period, making FEI out of sync with the other utilities.

For the attachment window, FEI's policy is to use projected connections for 5 years in the MX test. Given what FEI has actually seen in terms of housing developments, this window appears to be too short in some circumstances. While many of the other Canadian utilities use a similar timeframe, a 10-year timeframe is used by SaskEnergy, Union Gas and EGD.

Finally, the utilities all use the weighted cost of capital for discounting the forecast revenues when developing the present value. This is appropriate when inflation is applied to both the revenues and the annual costs. In the case of FEI the calculations are all assumed to be in real terms, excluding inflationary adjustments. The discount rate of 5% is then used to reflect a real rather than a nominal discount rate. This level approximates the difference between the utility's weighted cost of capital and the rate of inflation.

For revenue calculations, we recommend that the length of time used for calculating revenues be changed from 20 years to better reflect standard practice. The new time period should be consistent with the life of the assets, which in the case of FEI is set at 50 years or more as determined in the depreciation study approved by the Commission. It is recommended that a 40-year period be used to reflect the period used by other utilities and because extending the period beyond 40 years has a relatively small impact. FEI may also want to consider changing the attachment window from 5 years to 10 years if it continues to see projects that have a build-out period greater than 5 years.

Cost Calculations

In most cases site-specific costs for the connection are provided by engineers or contractors for each utility. For residential customers it is common to also use some standardized costs per unit as is the case with FEI.

All of the utilities surveyed incorporate overhead costs into cost calculations. These overheads include administrative & general (A&G), management and engineering expenses. While FEI uses an overhead adder of 23%, the range for the utilities surveyed run from 9% up to an estimated 50-100%. Note that these will vary considerably based on the accounting practices of each utility and what is included in various accounts. Some utilities may include engineering and management costs in the prices for extensions while others may only look at material and direct installation costs.

As the cost calculations for FEI are consistent with standard practice, there is no need to make major adjustments to this portion of the MX test. The one exception is the overhead rate of 23%. While this rate appears to be appropriate for small projects, in our experience over many types of utility projects, larger projects do not require much more overhead than a smaller project. This was confirmed by FEI staff based on their own experience with the level of effort required for their own extension-related projects. For that reason it is recommended that FEI consider the use of either a sliding scale or a cap on the total overhead amount so that the level of overhead charges to each project better reflects the additional cost and effort required to manage the project. While this is a more complicated approach than used by most utilities, it is consistent with GAZ Metro's use of a percentage that declines as the size of the project increases.

P.I. Targets

FEI's use of a 0.8 target for the P.I. on an individual basis, along with a 1.1 overall target, is consistent with the practices of the other utilities surveyed. While there are differences among the utilities, FEI is well within the range of options used. Union Gas and Enbridge Gas New Brunswick both use the same targets as FEI. Puget Sound Energy uses a lower 0.75 target while Heritage Gas and Manitoba Gas use a 1.0 target. The other utilities reviewed either don't have a set target or look at things in a different manner.

FEI's practice of using a lower individual target and a higher aggregated target allows for recognition of the potential benefits in the future associated with new extensions that are below 1.0 on their own, as well as the uncertainty in actual costs and benefits. Further, projects with a P.I. above 1.1 offset the added costs of those projects below 1.0, leading to an aggregated outcome that does results in holding existing customers harmless from the growth in customers.

Based on both standard practice and reasonableness, we believe the current FEI parameters for the P.I. target are appropriate.

The following table provides a summary of the various factors examined above and the resulting recommendations.

Issue	**Practice of Other Utilities**	**Recommendation for FEI**
Type of Test	All utilities use some type of cost-benefit analysis. In some cases a simplified calculation is made.	Continue with the current cost-benefit analysis used for the MX test.
Use per Customer	Utilities generally use the average amount by appliance to calculate revenues	Continue to use average use per appliance as determined by the REUS.
Rate Assumptions	Assume rates increase at the rate of inflation	Continue to keep rate projections at current levels with no inflation applied to revenues or costs.
Length of Analysis	Most utilities surveyed use between 30 and 40 years of revenues and costs.	FEI uses 20 years in the MX test. It is recommended this be changed to 40 years.
Connection Period	Some utilities use 5 years of connections while others use 10 years of connections.	FEI currently uses 5 years. Recommend that 10 years be considered, especially in cases where growth is planned over a longer period.
Overhead Costs	Utilities vary considerably with overhead adders ranging from 9% to 100%. One utility has a sliding scale.	FEI uses a flat 23% overhead rate. Recommend that the overhead be capped or a sliding scale be used for large projects.
P.I. targets.	Individual targets range from .75 to 1.0 but several utilities use the same targets as FEI. Several utilities use an internal rate of return rather than a P.I. ratio.	FEI uses 0.8 per project and 1.1 in aggregate. Recommend keeping these targets.

Reporting

While FEI is required to file annual reporting of actual main extensions, including both the actual costs and revenues, this is not a typical practice for other gas utilities. Only Gaz Metro is required to provide detailed annual reporting on actual extensions, along with an explanation of any differences that occur. This reporting is much simpler than required by FEI and includes only a comparison of actual costs to projections and an aggregated impact on rates for all projects. Puget Sound Energy files an annual update on actual extensions as a courtesy but it is not required to do so.

Many of the other utilities need to file information with their periodic revenue requirements filing showing the projected costs and benefits of distribution expansion projects above a certain dollar amount, as they do with any other capital project. This is also required for FEI. In some cases specific projects are questioned on occasion and looked at more closely to determine prudency. In the case of ATCO Gas any reporting requirements are being eliminated as part of the recently approved Performance Based Ratemaking (PBR).

Currently FEI has the most stringent reporting requirements of the utilities surveyed. In B.C., neither BC Hydro nor PNG are obligated to provide the annual reporting that is required of FEI.

It is recommended that the annual reporting requirements for FEI are either simplified or eliminated.

Financing of CIAC

Like FEI, most of the utilities surveyed require new customers to pay for any customer contributions up front prior to construction. There are a few cases where some type of financing is available. Gaz Metro allows customers to pay contributions over 24 monthly installments. Puget Sound Energy does not have a published policy regarding financing but will on occasion allow installment payments, without interest, over a short time period on a negotiated basis for large projects. Union Gas allows new customers to pay the 1.5% late fee amount as a way to defer full payment on required contributions. Both Manitoba Gas and Heritage Gas have financing available through an outside company.

Note that FortisBC offers financing of customer contributions for its electric customers. Financing is provided for contributions that exceed $2,000 and are limited to a total of $10,000 per applicant. The financing requires a 20% down payment, is available for a 1 to 5 year period, uses a rate equal to the weighted cost of capital, and is subject to approval of credit for the applicant.

While there are precedents for offering financing to its customers, FEI is not proposing to offer financing at this time as that is not its primary business focus. If there is a strong demand from customers for a financing option, FEI could consider offering a program affiliated with an outside company.

Trends Related to Uneconomic/Off System Areas

Both the NRRI report and CGA report talk about trends in funding expansion that may not be economic under traditional extension policies. The growth of natural gas supply in North America has resulted in improved competitiveness in natural gas relative to alternative fuels. The CGA report states that "Given the price and environmental advantages of natural gas over many alternative fuels, utilities, regulators, legislators, government leaders, and other stakeholders are re-examining the existing regulatory paradigm that requires new customers to pay an up-front CIAC to cover the difference between expansion costs and their expected revenues."[8] This trend has also expanded into Ontario and Quebec.

In Ontario, the Natural Gas Access Loan and the Natural Gas Economic Development Grant programs were recently announced. In the case of Ontario, the natural gas programs are being led by the Ministry of Economic Development, Employment and Infrastructure with support from the Ministry of Energy and the Ministry of Agriculture and Rural Affairs. Based on this initiative and guidelines from the OEB, Union Gas and EGD are intending to file new policies related to main extensions in the near future. FEI should continue to monitor these activities in Ontario.

In Quebec, Gaz Metro just announced the expansion of natural gas into the Bellechasse region based on a project with joint funding from the utility and government. The $35 million expansion will include $7 million in funding from Gaz Metro with the remaining amount funded by the government of Quebec. The project is expected to stimulate economic development, reduce GHG and save $2.5 million per year in energy costs.

In the U.S., several states have looked at options for easing extension policies to allow for greater gas availability, as summarized in both the NRRI and CGA reports. As with Ontario and Quebec, most of these practices resulted from either legislation or other government studies/recommendations that promoted the expansion of natural gas. Details associated with at least 6 states that had either passed or proposed legislation at the time the report was written were provided in the NRRI report.

For the states examined, changes associated with extension policies were allowed due to the following factors:

- Lower energy bills for customers
- Reduced air pollution
- Fewer price spikes related to oil
- Greater consumer fuel choice
- Economic development
- Increased discretionary income can help bolster the economy

[8] CGA Report, page 1

- Added convenience and reliability compared to oil and propane
- Absence of oil or propane tanks on properties

Specific regulatory changes made in the various states included:

- Changing payback periods from 15-20 years to a 25-year period
- Looking at projects on a portfolio rather than individual basis
- Charging a premium on rates to fund new projects rather than an up-front CIAC.
- Spending 50% of revenue from interruptible and off-system sales to offset expansion costs rather than be returned to customers, resulting in a fund of roughly $15 million for projects that had societal benefits of increased employment or economic development
- Funding of extensions in strategic areas where economic growth is forecasted
- Use of a cost tracker paid by all customers to fund a specified growth plan resulting in a 1.4% increase over 7 years
- Incentives to extend gas service for industrial projects along with a surcharge on all customers to fund projects
- Streamlined regulatory process with funding by all customers for projects that promote economic development
- Issuing general obligation bonds for uneconomic projects

The NRRI report also summarized various programs within Canada, although many of them occurred in the 1980's. Most of these programs (including Vancouver Island) included government funding of projects, however, part of the funding came from the utilities.

There are no government studies/mandates within B.C. to promote the expansion of natural gas in the Province and therefore FEI is not proposing to expand natural gas into off system communities that do not meet the MX test provisions at this time, however, serving those off-system communities may be appropriate to consider in the future. Monitoring activities in Ontario and Quebec will be important as this may provide some guidelines for the future in B.C.

The practices of various utilities identified in the report do in some cases support the other changes FEI is proposing to its extension policies. Further, there is a precedent within B.C. for funding certain projects that are otherwise considered uneconomic.

Funding of uneconomic projects is allowed for by BC Hydro under its Uneconomic Fund. This fund has been in place for roughly 30 year years and currently is funded up to $1.5 million per year. The fund is available to customers where the extension test shows a CIAC is required, and provides partial funding of the extension. This program is aimed at individual customer connections, typically in more rural areas, and does not apply to new housing developments.

The following provides the details associated with the Uneconomic Fund, as provided in BC Hydro's Electric Tariff, Terms and Conditions, Section 8.8.

> BC Hydro will budget funds annually to its Uneconomic Extension Fund which is intended to provide limited assistance to eligible applicants who are required to pay an extension cost for the construction of an Extension. Each year applications will be received and funds will be allocated on the basis of lowest cost per Customer connected to the BC Hydro distribution system.
>
> Applicants must apply for funding from the Uneconomic Extension Fund and will be subject to the following requirements:
>
> (a) For a single phase Extension to serve a Principal Residence on a parcel of land, the applicant shall pay:
>
> (i) an extension cost for the first Span of Line, including Transformation and a Crossing Pole, and the extension cost of any distribution line in excess of the next 800 metres beyond the first Span of Line; and
>
> (ii) for the next 800 metres beyond the first Span of Line, 10% of the Estimated Construction Cost and the present value of net operating and maintenance costs;
>
> (b) For a single phase Extension to serve a Principal Residence on a farm, the applicant shall pay:
>
> (i) an extension cost, for the first Span of Line, including Transformation and a Crossing Pole, and the extension cost of any distribution line in excess of the next 1200 metres beyond the first Span of Line; and
>
> (ii) for the next 1200 metres beyond the first Span of Line, 10% of the Estimated Construction Cost and the present value of net operating and maintenance costs;
>
> (c) For a single or three phase Extension to serve a farm irrigation load, the applicant shall pay an extension cost, on the complete Extension, less a contribution by BC Hydro of up to six times the estimated annual revenue. The maximum contribution by BC Hydro will be no more than the Estimated Construction Cost of the Extension.
>
> Applicants who contribute towards the construction of an Extension and who receive funding from the Uneconomic Extension Fund will not be eligible for any future refunds.

The Uneconomic Fund is a cost included in the annual revenue requirements of BC Hydro and is funded from customer rates. We believe it would be appropriate for FEI to offer a similar program funded through rates to provide a level playing field between the two utilities and to reflect the fact that while these types of extensions may not be immediately cost-effective, they have the potential to lead to future growth and could therefore prove to be cost-effective in future years. Further, this fund would lead to savings to the customer and could potentially provide other societal benefits that are not measured by the MX test.

As BC Hydro's current Uneconomic Fund is rather complex in its determination of the sharing of costs between the utility and the customer, it is recommended that the funding mechanism be simplified for FEI. This will provide greater customer understanding, allow a more straightforward and therefore faster evaluation process for the utility, and easier program administration. The end goal should be to provide a CIAC level for the customer that is part way between what they would pay under the MX test and full funding by the utility. The funding should also be set so that it would be advantageous for a typical extension to still use the standard MX test and resulting CIAC rather than the Uneconomic Fund.

As with BC Hydro, this cost should be fully funded from customer rates.

Rate Impact Analysis

To determine whether FEI's current extension practices and customer growth have been beneficial or detrimental to existing customers, a rate impact analysis was designed to quantify the effects on existing customers. The rate impact analysis was designed to determine how the impacts of multiple years of growth impacts overall rates. This approach can take into account whether the addition of capital costs from new customers is offset by the spreading of fixed costs over a higher amount of sales.

This analysis is not the basis of any actual spending proposals and is not intended to replace the system extension test methodology. Rather, the analysis was meant to demonstrate impacts that are not measured by the system extension test alone or by looking at changes in actual rates over time that are impacted by many different factors. The results support the premise that FEI can revise the assumptions for the system extension test, as it is proposing, without creating undue rate impacts on existing customers.

Methodology

The approach used to determine the ratepayer impact was to employ the same factors that are actually used when setting rates for the utility. While a seven-year period of historic growth and the capital costs associated with that growth was used, the methodology is intended to consider this growth in isolation so that all other factors impacting rates can be held constant. The analysis is intended to look at the growth as it if occurred instantaneously in 2015 and to look at the costs and benefits with and without that growth to determine if the growth itself would have led to a rate increase for existing customers.

When determining if a rate increase is needed, the utility looks at its revenue requirement compared to projected revenues based on expected sales to customers. The revenue requirement is based on the expenses of the utility and is made up of five basic components:

- Cost of Gas
- Annual Operating Expenses
- Depreciation
- Return on Rate Base
- Taxes

Because the cost of gas is a separate rate component that generates its own revenues, and the costs are a direct pass-through to customers, it has been excluded from the analysis.

Annual operating expenses include O&M of facilities, billing and customer service, and administrative and general expenses. The return, depreciation and taxes all reflect annual expenses that are associated with capital items that are found in the rate base or assets of the utility. In a cost of service study, these costs are allocated across the various customer rate classes (residential, commercial and industrial).

As we are basing the rate impact analysis on the actual costs and gas consumption provided in the most recent amalgamated revenue requirements for the total utility, the rate impact analysis looks at the impact for the amalgamated utility as a whole rather than for any particular rate class. This is because the installation of new gas infrastructure such as a main extension will typically serve a mix of residential, commercial and industrial customers and it is difficult to assess how many dollars of a particular main extension are related to serving the needs of residential versus commercial or industrial customers. As a result, the cost figures used in the rate impact analysis are the total actual costs for all customers.[9]

While the system extension test looks at revenues for one or more customers less the customers' share of costs for the utility, the rate impact analysis only looks at the incremental cost of adding new customers to the system.

The underlying theory of the approach is that while customers cause the utility to incur additional costs, that is offset by the fact that many costs of the utility are fixed in nature and do not increase as customers are added. When more customers and sales are added to the system, those fixed costs are spread out among more customers and that benefits all ratepayers. The rate impact analysis attempts to model both the added costs and the added benefit of the additional sales to new customers.

The analysis measures the revenue requirements before and after customer additions. It also measures the annual sales or gas consumption (GJ's) before and after customer additions. These two measurements allow us to look at the average cost per GJ and determine if it has increased or decreased as a result of the new customers.

Because there are many factors that impact rates over time, the analysis is designed to isolate the impacts of customer additions while holding all other factors constant. We started with the forecast revenue requirement and rate base from 2015. We then looked at the costs associated with actual additions for the time period 2008 through 2014, as if they occurred instantaneously. The 2015 revenue requirements was then calculated without the addition of those costs to reflect what it would have been if those new customers were never added. The sales in GJ's associated with those new customers were quantified and total sales with and without the new customers was determined. While growth does not occur instantaneously in real life, using that approach was necessary to exclude all of the other factors that impact rates over time, such as changing use for existing customers, inflationary increases in costs, and changes in technology that impact the utility's costs.

[9] Note that Fort Nelson has been excluded from the analysis as they are not included in common rates.

As stated earlier, the analysis looked at the incremental or marginal costs of new customers. In setting rates, costs are based on average embedded costs so that each customer pays their fair share of the costs of the utility. In looking at whether or not existing customers are better off when new customers are added to the system, incremental costs are more appropriate to determine the overall impact on the revenue requirements. Because of fixed costs for items such as transmission facilities, administrative expenses, regulatory costs and accounting, a 1% increase in customers does not necessarily lead to a 1% increase in costs. This is particularly true when a utility has surplus capacity on its system. This is currently the case for FEI as declining average use per customer has freed up capacity on the system that can be used to serve customer growth.

Revenue Requirements

The analysis starts with the revenue requirements/cost of service for the amalgamated system based on the 2015 test year, as filed in the 2015 Annual Review Filing Evidentiary Update Jan 29, 2015. The total is $757 million, excluding the cost of gas. This represents the total expenses of operating the utility for one year. After offsetting bypass revenues are accounted for, the net amount to be collected from retail rates is $727 million.

In order to determine the added costs associated with new customers, we included the costs associated with meters/regulators, services and mains for new customers as well as costs associated with Standing job orders and internal costs. The cost for these four capital items for the 2008-2014 period was $200.7 million[10]. Note that this reflects only the costs paid for by the utility and does not include any contributions in aid of construction (CIAC) paid for by the customer.

When the utility incurs capital costs, it does not add the capital cost to the revenue requirements in the year the costs are incurred. Rather, the ratemaking process allows the utility to collect a rate of return, depreciation and taxes associated with the capital additions. These three cost components reflect a total of 13.8% times the capital cost added to the revenue requirements in each year.[11]

The 13.8% multiplier was determined by looking at the expense items associated with return, depreciation and taxes relative to the rate base of the utility for the meters, services and mains categories.

When the 13.8% is multiplied by the capital additions of $200.7 million, the result is a cost per year of $27.8 million associated with customer growth. This reflects the cost to the revenue requirement associated with installing facilities to serve the new customers added to the system.

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[10] Taken from actual data for projects completed in the 2008-2014 time period for FEI, FEVI and FEW.

[11] This percent reflects the forecast for 2015. The actual percent may vary from year to year.

O&M expenses also increase as a result of new customers. Under the recently approved PBR mechanism, the Commission has determined that is it appropriate for FEI to increase O&M by one-half of the annual rate of growth in customers, and this assumption has been carried through into the analysis. Because this is the current level of O&M that will be allowed in the revenue requirements, this is the amount that would currently be used to determine the revenue requirements and resulting rates when FEI adds customers to the system. During the 2008-2014 period, a total of 85,348 new customers were added to the system. This reflects a total growth of 8.8% when compared to 2015 customers. To reflect the PBR decision, O&M costs associated with new customers added during the growth period was therefore set at one-half of the 8.8% growth rate. Given 2015 O&M costs of $238.1 million, the incremental O&M cost associated with new customers was calculated as $10.5 million[12].

The combined impact of the return, depreciation and taxes component plus O&M costs is $48.2 million. This amount was then subtracted from the original revenue requirements to reflect what the costs would have been if the new customers had not joined the system. The resulting net revenue requirements would be $678.5 million before customer growth.

Growth in Customers and Sales

After establishing the revenue requirement with and without the additional customers, the next step was to divide that by the total GJ for the utility with and without the new customers.

The starting point was based on the amalgamated customers and sales from 2015, including 970,399 customers and 174.6 million in GJ. As the revenue requirement is reduced by the revenues associated with bypass customers, the GJ sales for the year also excludes consumption for bypass customers. The sales amount represents all residential, commercial and remaining industrial rate classes (both sales and transport amounts) and results in an average blended use of 180 GJ per customer. For new customers, we assumed that average blended use for new customers was the weighted average for all new customers added in 2008-2014. The average use for each rate class and region were multiplied by the added customers for each rate class and region to determine the system-wide weighted average use of 134 GJ per customer. This is significantly less than the average use of existing customers due to the downward trend in use per residential customer resulting from more efficient appliances and reduced use of gas for heating purposes and the fact that the growth in large industrial customers was less than the proportion currently served by FEI.

The aggregate average use per customer was then multiplied by the added number of customers to determine the total added sales for the system. The number of customers was taken from the detailed actual information on customers added for the 2008-2014 period. When the average use per customer was multiplied by the number of customers, the result was

[12] $238.1 million x 4.4%

11.5 million GJ associated with customer growth. When this amount was deducted from the total system sales, the total resulting sales are 163.2 million GJ without customer growth.

Average Rate per GJ

The final step was to divide the revenue requirements by the sales in GJ to get the average rate per GJ before and after customer additions. The original average cost was equal to $727.2 million divided by 174.6 million GJ resulting in an average cost of $4.16 per GJ.

Without the addition of new customers, the result would be $689 million divided by 163.2 million GJ, or $4.22 per GJ without the customer growth from 2008-2014. This represents a savings of 1.4%, or $10.45 per customer due to the addition of new customers. When this amount is multiplied by the total number of customers on the system, the total annual impact is $10 million.

Potential for Additional Spending

As discussed in the section on theory, economies of scope create additional savings to existing customers. Based on the rate impact analysis, FEI's current MX policies have led to rates that are lower than if that growth had not occurred, despite the fact that large capital additions for mains, services and meters were required to connect those customers. This analysis indicates that existing customers have not been subsidizing new customers, and in fact, new customers have been subsidizing existing customers. The annual savings of $10 million associated with customer growth should be shared between both new and existing customers to reflect a balance of benefits between the two groups.

Given the magnitude of the savings, FEI could make significant changes in its extension policies without harming the existing customers. Given the 13.8% multiplier on rate base, an additional $10 million in annual spending would reflect capital additions that could have been up to $73 million more during the 2008-2014 period without having an adverse impact on existing customers. This represents up to a 37% increase in utility funded capital for new customers compared to current practice.

The following table provides the detailed results of the rate impact analysis for FEI.

		2015 With Growth	2015 Without Growth	2008-2014 Growth Amount
A	2008-14 Meters/Regulators			$16,026,762
B	2008-14 Services (Company Paid)			$119,082,263
C	2008-14 Mains (Company Paid)			$58,435,929
D	2008-2014 Standing Job Costs and Internal Costs			$7,228,180
E	Rate Base	$3,656,399,000	$3,455,625,867	$200,773,133
F	Return, Depreciation, Taxes	$522,883,000	$495,129,045	$27,753,955
G	Multiplier for Return, Depreciation, Taxes	13.8%	13.8%	13.8%
H	O&M Expenses	$238,093,000	$227,622,688	$10,470,312
I	50% of Customer Growth Rate			4.4%
J	Other Revenues/Expenses	-$3,942,000	-$3,942,000	$0
K	Offsetting Bypass Revenues	-$29,802,000	-$29,802,000	$0
L	Total Revenue Requirement (exc. Cost of Gas)	$757,034,000	$718,809,732	$38,224,268
M	**Net Revenue Requirement (exc. Cost of Gas)**	**$727,232,000**	**$689,007,732**	**$38,224,268**
N	Customers	970,399	885,051	85,348
O	Percent Growth in Customers			8.8%
P	Average GJ/Cust	180	184	134
Q	**Total GJ**	**174,623,400**	**163,169,382**	**11,454,018**
R	**Cost per GJ (exc. Cost of Gas)**	**$4.16**	**$4.22**	**-$0.06**
S	**Percent Difference**			**-1.4%**
T	**$ Difference per Original Customer** ***(Rate Impact per Customer per Year)***			**-$10.45**
U	**Cumulative Rate Impact**			**-$10,142,079**
V	**Equivalent Capital Spending with 13.8% Multiplier**			**$73,368,174**

Recommendations

Based on the utilities surveyed, FEI appears to be fairly consistent with the utilities in Canada in its use of the MX test and current P.I. targets. The current cost-benefit approach is relatively consistent throughout the utilities surveyed, with differences primarily in the underlying assumptions rather than in the methodology. While a few utilities offered a somewhat different approach to calculating the cost-benefit, none of those alternative calculations were as thorough as FEI's current method that considers a long-term present value of costs and benefits.

Changes in MX Test Parameters

There are a few areas that should be adjusted in the FEI MX test to be more consistent with the other utilities and with FEI's own accounting practices, which are explained in more detail below.

FEI's current system extension policies and MX test are for the most part consistent with other utilities in Canada. The approach has been in place for some time and is currently working adequately. The SLCA for service extensions and MX test for main extensions meet the theoretical standard of incremental pricing, whereby new customers cover the incremental costs of their connection that are not already covered within the existing rate levels. There are, however, some issues that it does not address well.

Given the issues associated with FEI's current extension policies and the standard practice seen across Canada, it is recommended that FEI make the following changes to its MX test:

- The timeline for revenue within the MX test should be expanded from 20 years to 40 years to be more consistent with the life of the assets.
- FEI should consider changing the attachment window from 5 years to 10 years in some cases.
- The 23% overhead adder should be changed to reflect a sliding scale or cap on the total amount for a given project.

Given the fact that existing customers are benefitting by $10 million per year due to the addition of new customers on the system, there is room to make these changes to the MX test without increasing rates for existing ratepayers.

Uneconomic Extensions and Off System Communities

There is also adequate savings in rates due to new customers to accommodate the establishment of a $1 million per year Uneconomic Fund comparable to that offered by BC Hydro. This would provide a tool to lessen the burden on those homes that currently would be required to pay a large CIAC, provide a level playing field with BC Hydro, and allow for extensions that could be built upon and serve additional customers in the future in an economic fashion.

Unserved communities provide a more difficult challenge. While there are precedents for funding programs for unserved communities, many were established in response to legislation designed to promote gas service expansion due to societal benefits. FEI should consider options for funding that would allow for service to unserved communities in the future, however, more work would be required to establish the societal benefits of such a program to be able to justify the program costs.

Other Issues

Two others issues to be addressed are the annual reporting requirements for FEI and the ability to offer financing for capital contributions.

The annual reporting requirements for actual costs and revenues for main extensions are inconsistent with standard practice in the industry, as most utilities are not required to submit after the fact reporting. While it is appropriate to determine whether or not the MX test results are valid, there are some inherent issues associated with the reporting. There is an issue with temporal inequities between new and existing customers as usage is declining over time. While the annual reporting may detect differences in actual usage levels compared to the assumptions made in the MX test, the methodology does not really measure the ultimate impacts on both new and existing customers. Further, basing main extension allowances on the basis of new more efficient appliances penalizes those customers that are making appropriate energy use decisions.

The rate impact model clearly demonstrates that existing FEI customers are actually benefitting from customer growth. This model provides a better indicator of the impacts of actual extensions than does the annual reporting. If reporting is to continue, it should be simplified to better reflect overall impacts.

While there are precedents for providing financing to customers for CIAC amounts, these programs are sometimes conducted by a third party to keep the utility focused on its core functions. If there is a large interest from customers for CIAC financing, it is recommended that the utility look to an outside party to provide the option to customers.

Line Extensions for Natural Gas: Regulatory Considerations

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Report No. 13–01
February 2013

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Acknowledgments

The author wishes to thank the Honorable James Gardner, Vice Chairman, Kentucky Public Service Commission; Laura Demman, Nebraska Public Service Commission; Robert Harding, Minnesota Public Utilities Commission; Cynthia Marple, Marple Rate Strategies; Professor Carl Peterson, University of Illinois Springfield; Joe Rogers, Massachusetts Attorney General's Office; and NRRI colleague Dr. Rajnish Barua. Any errors in the paper remain the responsibility of the author.

Executive Summary

The low price of natural gas in the U.S. has sparked interest in growing the use of this energy source. One example of this growth is residential, business, agricultural, and industrial energy consumers wanting to switch from oil, propane, and other fuels to natural gas. Many of these consumers reside in urban and suburban areas that previously had no access to natural gas, while others live in rural areas that still do not have access to natural gas.

Current and expected natural gas prices now make it economically sensible for more energy consumers to switch from oil or propane to natural gas. Switching to natural gas also may have broader public benefits, such as a cleaner environment, more reliable service, and economic development. With natural gas prices presently far lower than oil and propane prices, large-scale switching to natural gas could create public benefits substantial enough to warrant governmental actions. These actions can include financial assistance and market-facilitation support. Fuel switching might fit within a state's energy, economic development, or environmental policy. From an operational standpoint, the integration of new lines into a utility's existing distribution network can lead to internal efficiencies. These benefits can lower the average cost of a utility's service. Overall, switching to natural gas has the potential to save energy consumers substantial sums of money and contribute to a cleaner and more robust economy.

One factor for energy consumers switching to natural gas is the line-extension policies of utilities. Most state commissions require gas utilities to include these policies as part of their tariffs. Line-extension policies affect utilities' ability to extend their lines to new areas and specify the cost obligations of new customers (and property developers), which can determine whether natural gas would be cost-effective for these potential customers. These policies also can affect the prices charged to existing utility customers. Incremental prices, for example, tend to protect existing customers from the costs of line extensions and give prospective customers proper price signals on the economics of fuel switching. Yet, as some observers have argued, the alternative, rolled-in pricing, has the advantage of shielding new customers from the full costs of line extension. This cost allocation can avoid discouraging some prospective customers from switching when it would be economical and socially beneficial.

Many of the same principles that the Federal Energy Regulatory Commission applies to setting rates for interstate pipelines expansions apply to line extensions by gas distribution companies. An important principle is the justification for rolled-in pricing when existing customers benefit from an expanded pipeline network. Another principle, which tends to support incremental pricing, is giving new customers proper price signals in choosing a pipeline or an energy source. A third principle is to avoid undue price discrimination, in which prices to certain customers deviate severely from cost-based levels.

Three theoretical reasons exist for allocating a portion of extension costs to existing customers. First, a utility can earn net revenues or profits from new customers that translate into lower prices for all customers over time. As long as the utility is able to charge a high enough price to new customers to cover incremental costs, this condition should hold. The second reason is the existence of public benefits from fuel switching to natural gas. Society may not achieve the optimal amount of benefit from fuel switching if new customers bear all of the incremental costs. The third reason is that existing customers may benefit from economies of scope. These benefits occur when the stand-alone cost exceeds the incremental cost of providing service to one group of customers when the utility simultaneously provides service to another group of customers. These economies derive from the shared use of joint inputs in serving additional customers. That is, the cost savings derive from the complementary nature of a utility serving two or more distinct customer groups. The closer-to-optimal utilization of some utility resources could cause the utility's total average cost to fall, benefiting both existing and new customers.

The problem with the last two reasons for allocating line-extension costs to existing customers is that they are hard to quantify. The optimal subsidy or cost reallocation to existing customers requires knowing (1) the difference between the public benefit and private benefits, or (2) the benefits to existing customers from economies of scope. The preferred approach, consequently, might involve not allocating any incremental costs to existing customers, other than the portion that the utility can expect to recover over time from new customers, and assign all of the remaining additional costs to new customers. Most state utility commissions, in fact, tend to support this hybrid-pricing scheme in protecting both existing customers and utility shareholders. New customers alone pay for the "uneconomic" costs of new gas lines, while existing customers absorb the remaining portion of costs that a utility expects to recover from new customers over time.

Line-extension policies encompass several topics that regulators commonly grapple with. This paper addresses each of these topics, which are as follows:

1. Utility incentives for line extensions
2. Customer incentives for fuel switching
3. Utility cost recovery of incremental cost
4. Rolled-in pricing versus incremental pricing
5. Risk sharing and fairness among stakeholders
6. The appropriate economic test for utility investments in line extensions
7. The necessary conditions for subsidization of new customers
8. The proper role of the utility in promoting and facilitating fuel switching
9. Regulatory barriers to utility action; and
10. Affordability of economical fuel switching to prospective customers

These topics have the potential for becoming areas of contention in different ways in various kinds of situations. One topic of particular interest is the sharing of the incremental costs for line extensions between existing and new customers. Another topic of interest is determining the conditions required for subsidizing new customers. There is also the question of what constitutes subsidization. In all, line-extension policies challenge regulators on various fronts. Some commissions have even deviated from long-held ratemaking mechanisms to accommodate and promote fuel switching and gas-line extensions.

This paper starts with an overview of the extension policies of several states and gas utilities. It then discusses the myriad topics embedded in a line-extension policy. It follows with a model line-extension policy that state utility commissions can use as a guide. This model contains underlying objectives; it also addresses the challenges of developing a policy that balances these objectives (which sometimes conflict) for advancing the public interest. Finally, this paper makes recommendations to state utility commissions on what to avoid and include in a line-extension policy.

This paper is applicable to other public utility industries, namely electricity and water. Those two industries differ from the natural gas sector in that consumers have no good substitute to meet certain end-use needs (e.g., lighting, air conditioning). In most states, electric utilities have assigned and exclusive service territories, as well as an obligation to serve. Natural gas lacks this essential nature, as other energy sources are able to provide all the end-use services that natural gas does.

As far as the author knows, no comprehensive study of gas-line-extension policies exists. This paper offers state utility commissions insights on and an analysis of a topic that has grown in importance. The demand for distribution-line extensions has proliferated in recent years across various parts of the country. Commissions should consider seriously reviewing their gas utilities' line-extension policies in light of this development. They may find them to be incompatible with current regulatory objectives and conditions in the natural gas sector. The New York Public Service Commission, for example, recently initiated a new proceeding on examining policies associated with the expansion of natural gas service. Other state utility commissions may want to do the same.

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Line Extensions for Natural Gas: Regulatory Considerations

I. Reasons for the Study

The shale gas revolution has dramatically changed the outlook for natural gas in the U.S. Compared to less than five years ago, projections call for lower futures gas prices and abundant supplies well into the future. This new outlook has fostered industry action and governmental policies that aim to increase the consumption of natural gas both domestically and internationally. Most of the attention so far has focused on the increased use of natural gas for generating electricity. Yet increased attention has centered on efforts to (1) expand natural gas services to unserved areas and (2) grow gas usage in underserved areas that currently have gas mains. States, communities, and regions, for seemingly good reason, have advocated that businesses and households switch to natural gas.

Current and expected gas prices now make it economically sensible for more energy consumers to switch from oil or propane to natural gas. Switching to natural gas also may have broader public benefits, such as a cleaner environment, more reliable service, and economic development. As expressed in one study:

> As a result of…oil to gas conversions, Connecticut will have cleaner air, a lower carbon footprint and its businesses and homeowners will have lower production costs on the one hand and increased household consumption on the other. If the United States can tap further into its natural gas resources, conversion from oil to natural gas may in addition reduce our imports of oil and improve the nation's trade balance.[1]

This paper calls these benefits "public benefits." With natural gas prices presently much lower than oil and propane prices, large-scale switching to natural gas could create public benefits substantial enough to warrant governmental actions. Fuel switching might fit within a state's energy, economic development, or environmental policy. Overall, switching to natural gas has the potential to save energy consumers substantial sums of money and contribute to a cleaner and more robust economy.[2]

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[1] Stanley McMillen and Nandika Prakash, "The Economic Impact of Expanding Natural Gas Use in Connecticut," Department of Economic and Community Development, December 2011, 2 at http://www.ct.gov/deep/lib/deep/energy/cep/decd-the_economic_impact_of_expanding_natural_gas_use_in_connecticut.pdf.

[2] One caveat is that to the extent that state support for gas-system expansion makes urban sprawl more attractive, environmental costs could increase as people drive farther to work and energy use grows for other reasons. A policy to expand gas use, therefore, could conceivably be counterproductive in achieving a cleaner environment. The author thanks Dr. Carl Peterson for this insight.

In today's environment, policymakers should not overlook the possibility that consumers will make erroneous decisions based on the current low price of natural gas. It is likely that sometime in the future natural gas prices will rise again, conceivably at a sharply higher level. When energy consumers contemplate fuel switching, they should understand that their decision would have a long-term effect. Thus, state utility commissions and other governmental entities that encourage fuel switching carry the risk of harming customers over longer periods.

One factor affecting fuel switching, and the topic of this paper, is the gas-line-extension policies of utilities and state utility commissions. This paper focuses on fuel switching from oil and propane to natural gas that requires gas-line extensions.[3] Gas utilities, usually in their tariffs, have explicit rules on line extensions for both main and service pipes.[4] These rules, at the minimum, specify the economic test for line extensions, the financial and other obligations of new customers, mechanisms for utility recovery of incremental costs, and protections for existing customers. Some rules also distinguish between service lines and main lines, as well as areas that currently have underdeveloped main lines and new franchise areas without any main lines.

The reach of line-extension rules encompasses several topics that regulators commonly grapple with. Ten major ones are:

1. Utility incentives for line extensions
2. Customer incentives for fuel switching
3. Utility cost recovery of incremental cost
4. Rolled-in pricing versus incremental pricing
5. Risk sharing and fairness among stakeholders
6. The appropriate economic test for utility investments in line extensions
7. The necessary conditions for subsidization of new customers
8. The proper role of the utility in promoting and facilitating fuel switching
9. Regulatory barriers to utility action
10. Affordability of economical fuel switching to prospective customers

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[3] Fuel switching can include electricity and activities that do not involve the expansion of gas lines. These cases fall outside the scope of this paper.

[4] A main line delivers gas common to more than one customer. A service line delivers gas from a main line to an individual location, such as a house or business.

These topics have the potential for becoming areas of contention in different ways in various kinds of situations. One particular topic of interest is the sharing of the incremental costs for line extensions between existing and new customers.[5] Another topic is determining the conditions required for subsidizing new customers. There is also the question of what constitutes subsidization. In all, line-extension policies challenge regulators on various fronts. Some commissions have even deviated from long-held ratemaking mechanisms to accommodate and promote fuel switching and gas-line extensions.

As far as the author knows, no comprehensive study of gas-line-extension policies exists. This paper offers state utility commissions insights on and an analysis of a topic that has grown in importance. The demand for distribution-line extensions has proliferated in recent years across various parts of the country. Commissions may want to review their gas utilities' line-extension policies to ensure their compatibility with current regulatory objectives and conditions in the natural gas sector.

A session at the 2012 NARUC Summer Meetings titled "Going the Next Mile: How Utilities and Regulators Can Work Together to Get Natural Gas to Unserved and Underserved Communities" reflected regulators' interest in gas-line extensions. The word "unserved" refers to areas remote from the nearest utility's gas system.[6] A utility may have to make substantial investments to construct a new main line to serve these areas. An "underserved" area, in contrast, may have main lines nearby but many households and businesses that consume other forms of energy. It would be cheaper for the gas utility to connect new customers in "underserved" areas than in "unserved" areas. Differences in the costs may warrant a special policy for "unserved" areas.[7] For example, new customers may have to expend substantial dollars up front to pay their fair share of the incremental extension costs. Under certain conditions, subsidizing prospective customers to induce them to switch to gas might have some validity.

[5] In this paper, new customers can include property developers and other proxies for utility retail customers.

[6] See the presentation, for example, of Sonny Popowsky at http://www.narucmeetings.org/Presentations/PopowskySummerMeetings00157406.pdf.

[7] Minnesota was one of the early states to create a special policy for expanding gas service in unserved areas because it would be uneconomic for the utility, as well as burdensome to existing customers, under existing tariffs. (*See*, for example, Docket No. G-007/M-92-212.) As noted in this paper, options for funding such new extensions include a high surcharge on gas customers in unserved areas, a general rate increase that would burden all customers, and local government financial assistance paid for by taxpayers.

II. Summary of Gas-Line-Extension Practices

A. Common practices across states

This study did not a conduct a comprehensive survey of gas utility practices on line extensions. It instead reviewed the tariffs of several utilities that contain provisions on line extensions. The study noted several commonalities across utility practices, but at the same time, even for gas utilities in the same states, it observed distinct differences. As an example, a utility may provide "free" pipe extension up to a specified number of feet, while another utility in the same state may charge new customers for the entire footage. A second example is the method for calculating new customer financial obligations and the repayment period. Differences also lie with the economic test that utilities apply in evaluating proposed line extensions. Gas utilities in the same state may also differ in their promotion and marketing strategies for fuel switching.

One suggestion for state commissions, for consistency and fairness, is to consider establishing a statewide line-extension rule. The rule could specify: (1) the economic test, "free" allowances, and the ratemaking treatment of incremental costs; (2) utility financing for customer contribution; and (3) criteria for new customer contributions and refunds. Commissions might find that the current utility-by-utility tariffs are unfair and inefficient in addition to discouraging energy consumers from converting to natural gas. Fairness primarily involves balancing the interests of new and existing customers.

Utility tariffs commonly specify the "free" service and main-line extensions that new customers can receive and the amounts that they will have to pay for extensions that exceed the excess footage or costs. Most commissions adhere to the principle that any line extensions should not burden existing customers. In effect, most commissions apply a hybrid pricing mechanism that allocates: (1) the economic portion of new lines to all customers (rolled-in pricing[8] aspect) and (2) the uneconomic portion to new customers (incremental pricing[9] aspect). The rationale for the first part is that the utility expects to recover adequate revenues from new customers for the economic portion. The utility, in other words, expects to recover, at the minimum, its "economic" cost in rates.[10] Either existing customers would be held harmless or

[8] Under *rolled-in pricing*, the utility adds the costs of line extensions to existing costs with prices to all customers based on this sum. New and existing customers face the same price. Analysts often refer to rolled-in prices as average or embedded cost prices.

[9] Under *incremental pricing*, the utility's price for sales to new customers differs from the price for sales to existing customers; the incremental price includes the cost of new extension lines plus the share of the existing system's costs allocated to new customers. For example, the utility might charge new customers a premium price for a fixed time to pay for new extension lines. Incremental prices relate closely to the economist's notion of marginal cost.

[10] The capital expenditures for new lines, for example, would go into rate base, and the utility would depreciate the lines over some specified time (e.g., the lines' service life, five years).

benefit (when incremental revenues exceed the "economic" costs.[11] The incremental pricing component operates by charging new customers the "uneconomical" portion of the extension costs that would burden existing customers. Overall, the hybrid pricing mechanism has the feature of achieving a fair allocation of costs based on cost-causation and "beneficiary" principles[12]—at least, most gas utilities and state utility commissions believe that the hybrid pricing of new service produces these outcomes.

A regulatory question relates to whether a state should have a uniform policy and tariffs on gas-line extensions or continue with the common practice of utility-by-utility tariffs. The commission itself or the state legislature could mandate a uniform policy. A policy might include general principles and guidelines for line-extension activities. It might prescribe more detailed rules; for example, allowing a utility to request a waiver of the policy if warranted by specific circumstances.

One conspicuous observation is the *ad hoc* nature of rules. Little rationale seems to exist for some of the provisions. Consequently, and for other reasons noted later, state utility commissions may want to revisit these rules to assess their reasonableness and compatibility with today's gas-market environment. Because of the increased attractiveness of natural gas, commissions may want to consider whether existing rules pose excessive obstacles to fuel switching that is in the public interest.

B. Specific examples

In some states, gas utilities, state utility commissions, and legislatures have taken proactive positions on promoting line extensions and fuel switching. A summary of these actions follows.

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[11] Under traditional ratemaking, when a utility collects additional revenues that exceed incremental costs, rates to all customers would tend to decrease. In the instance at hand, existing customers may see higher rates initially but lower rates in the end. In effect, they act as lenders to new customers who receive an up-front payment for a portion of the line extension costs (e.g., "free" footage) and repay existing customers through rates over some specified period. Unless utility shareholders compensate for lower-than-expected future revenues from new customers, existing customers absorb the risk.

[12] For example, the restriction of recovering only "economic" costs from existing customers avoids those customers' having to pay for costs that benefit solely new customers.

1. Nebraska

Nebraska has passed legislation facilitating the expansion of gas lines into new areas.[13] Legislators hope that by lowering the energy costs of businesses and industries, the legislation will promote economic development and job creation in rural areas.

The legislation streamlines the regulatory review process in addition to allowing utilities to spread the costs of line extensions to all of their ratepayers.[14] One of its provisions requires the different stakeholders—including gas utilities, municipalities, local businesses, and investors—to come before the Public Service Commission with a plan for line extension. The plan must consider the economic effect on the area, economic feasibility, and other options that would better advance the public interest.

The parties could request recovery of the costs from all of the utility's customers if the plan promotes economic development in an unserved or underserved area. The intent is to bolster financial support for expanded pipeline infrastructure that new customers alone are unable to fund. The legislation addresses the concern that allocating all the cost of a line extension to a single customer or a small group of customers would make fuel switching cost-prohibitive. It allows a utility to impose a surcharge that is separate from general rates.[15] The legislation also recognizes the possibility that municipalities located in remote areas would fund line extensions or provide other assistance for the purpose of economic development.

2. North Carolina

North Carolina has provided financial support for line extensions that fail an economic test. The North Carolina Clean Water and Natural Gas Critical Needs Bond Act of 1998 authorized the issue of general obligation bonds for natural gas extensions that are not economically feasible. The state General Assembly also enacted legislation that allows the creation of expansion funds for the extension of gas service to unserved areas. Gas utilities can apply the funds only to economically infeasible expansions, or to expansion estimated to produce

[13] Legislative Bill 1115 passed in July 2012. *See* http://nebraskalegislature.gov/FloorDocs/102/PDF/Final/LB1115.pdf.

[14] The latter provision is particularly noteworthy, as the state's statutes prohibit subsidization and discrimination in utilities' rates, defined as a distortion of cost allocation relative to cost-of-service principles. The new legislation makes gas-line extensions in certain circumstances an exception. In states that prohibit subsidization, new customers are responsible for all of the line-extension costs that are unrecoverable by the utility.

[15] This treatment required a change in the state Natural Gas Regulation Act.

a negative net present value.[16] Funds can come from a surcharge imposed on existing ratepayers, supplier refunds, and other sources approved by the Utilities Commission.

Both legislative actions facilitate the development of the natural gas infrastructure in remote areas of the state where the economics would otherwise preclude development.[17] By all accounts, these actions have bolstered the development of the natural gas infrastructure throughout the state.

3. Delaware

Chesapeake Utilities has proposed a hybrid cost-recovery mechanism for line extensions before the Delaware Public Service Commission.[18] The proposal also includes the utility providing services that: (1) facilitate customer conversion to natural gas and (2) offer loans and other financial programs allowing new customers to pay their line contributions over a number of years. The utility also proposes to apply the internal rate of return (IRR) method to evaluate line-extension projects. (Part III.C.2 of this paper discusses the IRR method.)[19]

The hybrid mechanism contains two components: One recovers costs only from new customers (the infrastructure expansion service rate[20]), and the second recovers certain costs associated with line extensions from all ratepayers (the distribution expansion service rate).[21] The proposal combines both incremental and rolled-in pricing principles.

As noted in its testimony, Chesapeake contends that:

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[16] The net present value equals the present value of expected future cash inflows minus the present value cash outflows over the life of the new lines.

[17] *See Report of the Public Staff North Carolina Utilities Commission to the Joint legislative Commission on Governmental Operations: Analyses and Summary of Expansion Plans of North Carolina Natural Gas Utilities and the Status of Natural Gas Service in North Carolina,* April 24, 2012, 3-5 at http://www.pubstaff.commerce.state.nc.us/psngas/publications/bireport.pdf.

[18] At the time of this writing, the commission had not decided on the proposal.

[19] *See In the Matter of the Application of Chesapeake Utilities Corporation for Approval of Natural Gas Expansion Service Offerings to be Effective September 1, 2012*, Docket No. 12-292, application filed with the Delaware Public Service Commission, June 25, 2012 at http://depsc.delaware.gov/dockets/12-292%20app.pdf .

[20] This rate would recover most of the construction costs for new pipes.

[21] The utility proposes to integrate both rates into the monthly customer charge. The distribution expansion service rate will support administrative-related activities associated with the offering of gas service in expanded areas.

> Chesapeake's proposal will accelerate expansion of natural gas service with minimal impact on the cost of service for existing customers as compared to what they are paying today.[22]

The utility describes the proposal as an expanded version of energy efficiency: Fuel switching to natural gas has several benefits, including saving energy and contributing to a cleaner environment. A state workgroup previously issued a report that agrees with this assessment:

> Given the benefits of natural gas and the potential energy savings on a full-fuel-cycle basis, the Workgroup supports the expansion of gas service in all areas of the state and recommends inclusion of fuel switching and gas fired combined heat and power systems (CHP) toward energy-efficiency savings.[23]

4. New York

The New York State Energy Plan of 2009 stated that:

> In situations where expansion of natural gas facilities into new areas is not economically viable, it may be possible to receive contributions towards the costs of the expansion facilities from potential customers, interested municipalities in the region, and state economic development funds.[24]

In November 2012, the New York Public Service Commission initiated a technical conference on the study of policies for the expansion of natural gas service.[25] The initiative is in response to Governor Cuomo's Energy Highway "Blueprint." The document requests: (1) an examination of existing barriers to the expanded use of natural gas service by residential and businesses customers in the state and (2) appropriate measures to mitigate potential barriers.

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[22] *See In the Matter of the Application of Chesapeake Utilities Corporation for Approval of Natural Gas Expansion Service Offerings to be Effective September 1, 2012*, 12.

[23] *State of Delaware Energy Efficiency Resource Standards Workgroup Report*, June 2011,3 at http://www.dnrec.delaware.gov/energy/information/Documents/EERS/Final%20EERS%20Workgroup%20Report.pdf.

[24] New York State Energy Planning Board, *New York State Energy Plan 2009*, Volume II (Natural Gas Assessment), December 2009, 4 at http://www.nysenergyplan.com/final/Natural_Gas_Assessment.pdf.

[25] State of New York Public Service Commission, *Proceeding on Motion of the Commission To Examine Policies Regarding the Expansion of Natural Gas Service, Order Instituting Proceeding and Establishing Further Procedures*, November 30, 2012 at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B33008B64-79D4-4DD3-B222-442061E06BAE%7D.

The Commission recognizes the potential benefits from expanded natural gas service:

> Natural gas is cleaner than other fossil fuels used for home heating and under current market conditions costs a third as much. Moreover, New York State is well-located geographically to take advantage of existing and newly developed natural gas supplies located outside our State but which, when competitively-priced, are available to supply customers within the State. New York's location relatively close to these new sources of supply could provide the State a competitive advantage in attracting and retaining employers concerned about costs of, and access to, a reliable source of energy. In addition, consumers may enjoy significant savings in household fuel expenses which in turn could benefit the State's economy to the extent that households redeploy those savings.[26]

The Commission expressed the need to revisit its policies on natural gas expansion in view of recent developments in gas markets. Specifically, the Commission noted a concern over the "subsidization of expansions by existing ratepayers, particularly as such benefits shareholders."[27] The Commission order asked utilities and other stakeholders to respond to 21 questions. Commission staff will include the responses in a report to the commissioners.

5. New England

Especially worth noting are efforts in New England to promote fuel switching from oil to natural gas. This region still has a large number of customers using fuel oil for space heating. Conversion to natural gas has the potential to save consumers large sums of money. In Maine, many oil and propane consumers would like to convert to natural gas, and competition for operating in unserved areas has intensified. A new law signed in 2012 authorizes the Finance Authority of Maine to issue bonds for the development of the state's natural gas infrastructure.[28]

Connecticut has proposed legislation that will promote fuel switching as part of the state's energy strategy.[29] Supporters contend that households could save thousands of dollars annually by converting from oil to natural gas and that businesses could substantially lower their

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[26] Ibid., 1.

[27] Ibid., 8.

[28] *See* http://www.kjonline.com/news/gas-pipeline-pitched-in-winslow_2012-12-10.html and https://bangordailynews.com/login/?redirect_to=https%3A%2F%2Fbangordailynews.com%2Fposts%2F.

[29] "SB 450, An Act concerning Energy Conservation and Renewable Energy," Connecticut General Assembly, *OLR Research Report*, 2012-0R-0153, March 20, 2012 at http://www.cga.ct.gov/2012/rpt/2012-R-0153.htm.

energy costs, making them more competitive. They recognize the barriers to fuel switching that legislation or regulatory policies can redress.[30]

Vermont has allowed its only gas utility (Vermont Gas Systems) to use ratepayer monies to start planning for line extensions that could save households and businesses large sums of money in the future. The Vermont Public Service Board reasoned that the potential benefits from expanding gas service in the state outweigh any concern over ratepayers funding development and planning costs in the near term. The Board identified these benefits as the reduction in greenhouse gases and increased economic development.[31]

6. Pennsylvania and Virginia

Pennsylvania also hopes to expand gas service into rural and other areas where gas is currently unavailable.[32] The state now has an abundance of natural gas that it wants allocated to in-state households and businesses that currently consume higher-priced and more environmentally damaging forms of energy. Virginia has passed legislation that will facilitate the recovery of costs for eligible gas-line extensions that promote economic development.[33]

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[30] The Governor hopes to have 300,000 customers convert to natural gas as part of his energy plan. Currently, only about 31 percent of homes in Connecticut have natural gas heat; the typical oil-heat customer spends about $2,650 a year on fuel and the typical gas customer spends just $1,100. The Governor and others see conversion to natural gas creating jobs, making in-state business more competitive, and improving the environment. One problem they noted is the high cost of extending a gas line to a street that lacks one. *See* http://articles.courant.com/2012-10-05/business/hc-energy-plan-1005-20121004_1_natural-gas-energy-efficiency-water-heaters.

[31] One board member dissented, saying that Vermont Gas Systems should instead use the parent company's money to support these activities. He also contended that the arrangement poses an inter-generational equity problem. Finally, he asks why current ratepayers should fund an activity that, if successful, would benefit utility shareholders in the long run. Another concern was that using ratepayer money to expand gas-distribution lines might place competitors, who do not have the same opportunity, at an unfair disadvantage. *See* Vermont Public Service Board, *Request of Vermont Gas Systems, Inc. to establish a System Expansion and Reliability Fund with funds provided by reductions in the quarterly Purchase Gas Adjustment rate under the Alternative Regulation Plan, Order Amending Alternative Regulation Plan,* Docket 7712, September 28, 2011.

[32] "Demand for Natural Gas Distribution Lines Focus of Rural PA Hearing," press release from State Senator Gene Yaw, April 12, 2012 at http://www.senatorgeneyaw.com/Press/2012/0412/041212.htm. An email received by the author from the Director of the Pennsylvania Center for Rural Development, on November 29, 2012, indicated that Senator Yaw's group is working with the Public Utility Commission, communities, and gas utilities to explore initiating "a pilot project just to see what works, what problems we run into, what lessons we learn and how that could shape a more formally structured state-level gas service expansion program."

[33] *See* http://leg1.state.va.us/cgi-bin/legp504.exe?121+sum+HB559.

Appendix A lists the major activities in nine states. Initiators of these activities include gas utilities, utility commissions, energy consumers, local governments, and state legislatures. The objective in all instances is to facilitate the expansion of gas service to unserved and underserved areas in the respective states. All of these states believe that fuel switching to natural gas has the potential to produce large public benefits.

III. Topics of Regulatory Interest

Gas-line extensions involve several topics of regulatory interest. As in most other regulatory matters, specific actions, while apparently attractive at first sight, might produce unexpected costs and, overall, negative outcomes. While in principle gas-line extensions seem like a good idea, how utilities carry them out will determine their social desirability.

A. Fuel switching

1. Recent trends

In most regions of the country, excluding rural areas, households and businesses can choose between natural gas and other energy sources. Consumers normally make these choices when their existing appliances become either physically or economically depreciated,[34] or when they purchase or build a new house. The U.S. has seen a large number of households shifting from one fuel to another over time. In 1950, over half of American households with space heating equipment used either coal or oil for space heating; by 2009, only 6 percent did. Over that same period, the combined natural gas and electricity share rose from 27 percent to 83 percent.[35] In the last twenty years, New England households have shifted in large numbers from oil to natural gas.[36] Households and business continue to switch, as oil prices rise relative to natural gas prices. Even the Pacific Northwest, where electricity is relatively inexpensive, has

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[34] Economic depreciation occurs when a household has an old gas furnace that is still functional but only has a few years of life left and is costly to operate relative to a more efficient gas furnace or electric heat pump.

[35] U.S. Energy Information Administration, *Residential Energy Consumption Survey (RECS), 2009 RECS Survey Data* at http://www.eia.gov/consumption/residential/data/2009/xls/HC6.7%20Space%20Heating%20by%20Census%20Region.xls.

[36] The percentage of households in New England using natural gas as their main space heating fuels increased from 28 percent to 40 percent during 1997-2009. Over the same period, oil's share fell from 51 percent to 42 percent. *See* U.S. Energy Information Administration, *Residential Energy Consumption Survey (RECS), 2009 RECS Survey Data* at http://www.eia.gov/consumption/residential/data/2009/xls/HC6.8%20Space%20Heating%20in%20Northeast%20Region.xls.

seen many households convert to natural gas for space and water heating. Energy market shares vary widely across regions. Natural gas water heaters dominated in most regions of the country.[37]

Notwithstanding these trends, the recent surge in natural gas supply has generated interest in accelerating fuel switching to natural gas.[38] We have already discussed the potentially large private and public benefits from fuel switching. Energy consumers can save large sums of money that they can spend on other goods and services. This increased discretionary income can bolster the local and state economy. Consumers also directly benefit to the extent that natural gas is more convenient and reliable than oil or propane.[39] Natural gas has environmental advantages over oil. Finally, an "amenity" benefit derives from the absence of an oil or propane storage tank on one's property.[40]

2. Economic and other factors

The major drivers for fuel switching in the U.S. are the relative prices of different energy sources, climate, environmental regulation (e.g., removing coal for home use), and increased natural gas availability. Fuel availability is a requisite for choice. Rural areas use little natural gas because of the scarcity of gas-distribution lines. This scarcity stems from the cost-ineffectiveness of extending lines to these areas. Natural gas is the fuel of choice in most areas where households have access to a gas-distribution main.

a. Cost-effectiveness

The cost-effectiveness of fuel switching relies on several factors: (1) conversion costs,[41] (2) the cost of additionally required natural gas connections or extension lines, (3) the avoided cost of oil or propane (e.g., fuel and other operating costs, capital costs), and (4) the incremental cost of natural gas (e.g., purchased gas costs and any additional distribution costs). The most cost-effective fuel choice often correlates with the specific conditions of a home. One specific condition is the amount of energy used in a home. Home energy use depends directly on a

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[37] *See* various issues of the U.S. Energy Information Administration's *Annual Energy Review* and *Household Energy Consumption and Expenditures*. *See* http://www.eia.doe.gov/emeu/aer/contents.html.

[38] *See*, for example, the activities discussed in Part II of this paper.

[39] For example, natural gas offers less chance of non-deliverability of energy and service shut-offs because of extreme weather conditions.

[40] Another possible benefit is protection against shut-offs during cold weather. Some states prohibit shut-offs by delivered-fuel providers, such as propane suppliers, but other states do not. The author thanks Bob Harding for this insight.

[41] Conversion costs include heating-equipment replacement, internal piping, and a meter.

number of factors including house size, the thermal efficiency of the house, climate, and the preferences for indoor ambient temperature. The attractiveness of specific fuels also depends on energy prices and their expected escalation rates. Important factors of fuel switching to natural gas are the costs of conversion and delivering gas to the house or business.

b. Micro-consumer factors

When making energy choices, consumers usually look at different factors that relate to the costs they expect to incur over the life of energy-using equipment.[42] These costs include: (1) purchase and installation; (2) annual operating cost, mainly the cost of fuel; (3) repair or maintenance cost; and (4) service life. Switching forms of energy also may require special plumbing or retrofit work. Energy choices are often house-specific. Two homes in the same city may reach different decisions on what energy sources to use because of differences in home size, building-shell energy efficiency, and the energy services desired. A small home that is highly energy efficient may opt for electric resistance heating, while a large home that consumes large amounts of energy may prefer natural gas for space heating. Fuel switching to natural gas can make sense for some customers but not others, even when they live in the same neighborhood.

3. Barriers to fuel switching

Theoretical arguments on why consumers sometimes make uneconomic decisions focus on market barriers or imperfections, including: (1) imperfect information, (2) consumer inertia, (3) high customer discount rate,[43] (4) lack of consumer access to capital, and (5) high transaction costs. Some of these barriers prevent consumers from making decisions that are in their self-interest; others reduce society's welfare. Energy-efficient gas equipment generally, for example, has higher initial cost than corresponding electric equipment. This cost differential, assuming consumers heavily discount the benefits of lower energy cost over the life of the equipment, favors certain energy sources even when lower gas prices may make gas preferable on a lifecycle-cost basis. Some consumers may decide not to switch to natural gas because of the combination of high conversion costs and their share of the cost for gas extension lines.

It would be wrong to consider all of these barriers as impediments to better market performance, thereby justifying market intervention. Inertia may reflect the reluctance of some consumers to change suppliers or products because of uncertain outcomes that could make them worse off. Some consumers might feel that low gas prices are only temporary and that they will give way to much higher prices in the future. It would therefore not be cost-beneficial to eliminate or mitigate the effects of all "barriers."[44] Trying to measure in dollars the

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[42] The lifecycle costs measure the money spent on energy over the life of the appliance in present value terms.

[43] A high discount rate means that potential natural gas customers place a diminished value on future benefits that could cause them not to switch when it would be in their long-term interest.

[44] Such risk aversion is a perfectly rational response to uncertainty.

environmental benefits of consumers' switching fuels, for example, could be costly and grossly inaccurate.[45]

In doing their part, state utility commissions might want to consider reviewing their policies and practices to make sure that they do not favor a particular fuel. Their objective should be to reduce transaction costs and other barriers with the goal of promoting efficient fuel markets. Theory suggests that when consumers have access to better information and lower transaction costs, they will be more likely to switch to another product or service. The implication is that, under these conditions, consumers are more apt to substitute one form of energy for another if the information shows long-term benefits.

4. Governmental intervention

Market forces have had the largest effect on the energy-choice decisions of consumers. With adequate information and good decision-making, consumers can best make those choices, and most often they do. This fact, however, does not preclude justification for regulatory and other governmental actions when market problems distort decision-making.

The test that state utility commissions can apply to assess the appropriateness of regulatory intervention in fuel switching is similar to the test they use to assess utility initiatives promoting energy efficiency. Most commissions mandating utility energy-efficiency initiatives require that these initiatives pass some cost-effectiveness test. Commissions generally ground these initiatives on the premise that market problems have hindered consumers from making energy-efficiency investments that are in their own self-interest in addition to society's interest. They might inquire into market problems that relate to fuel-switching decisions, as well as those that relate to energy-efficiency decisions. Commissions should examine the benefits and costs of such intervention. After review of these matters, a commission might well decide to institute a policy of promoting energy efficiency and not fuel switching, or vice versa or both. The combination of existing customers using natural gas more efficiently and oil and propane consumers switching to natural gas may optimize social welfare. Subsidization of line extensions by charging new customers below incremental cost, as an example, may bolster fuel switching on grounds of positive externalities (i.e., an increase in public benefits and social welfare) that energy consumers or utilities do not consider in their decisions. A utility subsidy can include rebates and other financial incentives for furnaces and other gas equipment.

5. Behavioral economics and fuel switching

Behavioral economics combines economics and psychology to explain how people make decisions. It assumes "bounded rationality," where people make decisions with less-than-perfect information because of limited time and mental capacity. People often exhibit what some

[45] Economists generally agree that measuring the benefits of a cleaner environment is imprecise, largely because of the difficulty of assigning a dollar value to the outcome. How much, for example, is a locality willing to pay for fewer emissions of particulate matter, sulfur dioxide, and carbon dioxide when energy consumers switch from oil and propane to natural gas?

analysts call "rational ignorance."[46] People are susceptible to making predictable and avoidable mistakes. Specifically, behavioral economics would say the following about fuel switching:

- **Real-world decision making is often inconsistent with neoclassical theoretical models of consumers making rational decisions.** Consumers make decisions in a complex environment where uncertainty, transaction costs, and conflicting information exist. Some consumers may consider these factors crucial for decision making. At first sight, it may appear rational for consumers to substitute one form of energy for another. Yet less obvious factors could make taking no action seem the more sensible course. Many customers fail to exploit fully the available information in deciding whether to switch. Reasons include confusion and bounded rationality. Customers might have difficulty processing the information—that is, using it to make good decisions. With "fuel switching," initially customers had little or no experience.

- **Policymakers can "nudge" consumers into actions that are most beneficial to the consumer.** By informing consumers of their financial losses from not substituting one form of energy for another, policymakers can "nudge" consumers to make better choices. For example, regulators can post on their websites that switching to natural gas can save the average residential customer $1,500 per year.

- **The human tendency is toward "inertia," which some people would call laziness.** Because deliberating over whether to switch to one form of energy requires effort and time, the opportunity cost for many consumers may exceed their expected benefits. Unless natural gas or some other energy source offers clear advantages (for example, large cost savings), in view of time constraints and other matters of higher priority, why should anyone spend time deliberating over energy choices? In switching to natural gas, the reality is that many energy consumers would likely see large cost differences.

- **Making information clearer to consumers may facilitate consideration of their choices.** By making price and lifecycle comparisons between fuels easier, in addition to providing information on the pluses and minuses of fuel switching, consumers are apt to be more active. Utilities, consumer groups, and regulators can work together to assure that consumers have unbiased and sufficient information.

- **In economic activities like fuel switching to natural gas, where an investment involves short-run costs much greater than short-run benefits, consumers might forgo change even though investments in fuel switching may result in higher returns in the end.** Behavioral economists call this myopic behavior "faulty

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[46] *See*, e.g., Richard H. Thaler and Cass R. Sunstein, *Nudge: Improving Decisions about Health, Wealth, and Happiness* (New Haven, Yale Univ. Press, 2008); and Robert H. Frank, *The Economic Naturalist: In Search of Explanation for Everyday Enigmas* (New York, Basic Books, 2007).

discounting." This phenomenon exists to varying degrees in most markets and is difficult to thwart, especially at a low cost and without creating new distortions.

B. Distinction between main-line and service-line extensions

Service lines directly benefit only individual customers. By constructing a line from the street to a house, the residents of the household are the sole beneficiaries. For main lines, a group of new customers benefit. Some customers benefit earlier than others do, as new customers on a single main line sequentially sign up for service over time.

1. Three categories of benefits

We can classify new line extensions into three different groups according to the scope of their benefits. At one extreme are extensions that benefit only new customers: Utilities dedicate service lines to individual households and businesses and main lines to a group of geographically adjacent customers. The implication for pricing and cost recovery is that the utility should allocate all of the incremental cost to new customers. The reason is that private benefits equate to public benefits.

Other extensions benefit mostly new customers, but also can benefit existing customers, although to a much lesser degree. As discussed later, these differences have implications for allocating the costs of extensions. For example, to the extent that existing customers benefit, one can argue that they should pay for a portion of the line extension. Even if existing customers do benefit, utilities dedicate new lines to serve new customers. Existing customers would benefit only as a residual effect from integrating the new lines into a gas utility's distribution network. These benefits presumably are small compared with the direct benefits to new customers. This integration could lower the utility's average cost. If a utility is unable to measure these residual benefits, it might then be appropriate to ignore them for ratemaking purposes.

A third category of new lines can have wider benefits. If they are large in capacity, they can make a concrete contribution to economic development and a cleaner environment. They could also provide some minor reinforcement and reliability benefits to other parts of the utility's distribution system. Under these conditions, policymakers might want to consider subsidies from taxpayers or other governmental assistance to bolster line extensions.[47] As mentioned later, however, they should exercise caution before committing taxpayer money to an investment that, as a rule, the private sector should fund.

2. Main lines offer more challenges for policy

Rules for service-line extensions should be simpler than rules for main-line extensions. The utility can simply calculate the cost for a service extension to an individual home or business

[47] As an alternative, policymakers could institute a Pigovian-like tax on the environmentally damaging fuels, such as oil and propane, to support conversion to natural gas.

and then determine, based on the approved regulatory rules, how much to charge the new customer (e.g., via a surcharge or in rates, or both).

Main lines, in contrast, serve an unknown number of new customers. The utility would expect the number of new customers served by main lines to increase over time. Assume, for example, that a new main line costs $10 million, and initially 1,000 new customers sign up for service. Assuming that new customers pay for the entire amount, the utility would assess each customer $10,000. Assume now that the number of customers using the main line grows to 2,000 after five years. Most people would consider it unfair for the utility to charge the later new customers nothing for the main line while continuing to collect $10,000 from each initial new customer (over, for example, a 15-year time period). Through its regulatory-approved rules, the utility may charge the 1,000 additional customers $5,000 each and refund each of the initial new customers $5,000.[48] The outcome is that each new customer pays the same amount for the new line ($5,000) and the utility recovers fully its cost for the line ($10 million). This equal treatment of new customers is common among utilities.

C. Economic tests for line extensions

1. General conditions for expanded service

When should a utility extend its lines? Should it be any time a prospective customer wants gas service? This unconditional requirement would seem reasonable if the party is willing to pay the full cost for a line extension. Assume, for example, that an individual living in a remote area wants gas service. The utility estimates that it would cost $50,000 to expand a main line and construct a new service line. We assume that the utility finds the line extension uneconomic, or financially infeasible.[49] Few customers would probably pay this full amount, so the question comes down to how much the prospective customer should pay relative to the utility's ratepayers and shareholders, and even taxpayers.

Utility tariffs often include the provision that a utility has an obligation to extend its lines only if the expected revenues from new customers cover the incremental costs. As an example, the practice of New Mexico Gas is:

> In accordance with the [gas-line-extension policy], the Company is required to invest in extensions of its distribution mains to satisfy a customer's natural gas

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[48] A common practice of utilities is to refund excess new-customer advance payments or contributions when they experience unexpected growth in customers on a new main line. Some utilities make refunds when annual revenues exceed expectations.

[49] The utility is unlikely to earn enough profits, or distribution margins, from these customers over time to support the $50,000 investment.

> service needs only when it is economically prudent for the Company to do so based on the probable revenues and expenses to be incurred.[50]

Most utility tariffs supplement this provision by specifying that new customers can make up for any revenue shortfalls. They recognize that if the utility extends its gas lines to oblige oil or propane customers, the new customer should assume some financial responsibility to hold both the utility and existing customers harmless. For example, new customers can pay a special surcharge or make an advance payment to the utility.

One fundamental difference to note with electricity is that gas service is not as essential because customers can always consume some other energy source (e.g., oil or propane) to satisfy their end-use demands. We should expect regulators to more willingly mandate service extensions by electric utilities. Most states, in fact, have a statutory universal service goal or mandate for electric service, but not for natural gas.

Is constructing new gas lines to accommodate consumers' desires to switch from one fossil fuel to another a "public need"? The consumer's main interest is in lowering his energy cost, not in acquiring new energy services (e.g., water heating, space heating, or cooking). Rather than serving a "public need," fuel switching, as discussed in Part II, reflects a customer-choice decision that some readers might conclude falls outside the definition of a "necessity."

2. Specific tests for comparing revenues with costs

Most utility tariffs reviewed for this study specify an economic test that compares expected revenues from new customers with the utility's incremental costs. In other words, the utility calculates both the incremental costs and the revenues from a line extension. The following excerpt from a gas utility's tariff exemplifies this point:

> CenterPoint Energy [in Minnesota] will apply the general principle that the rendering of gas service to the applicant shall be economically feasible so that the cost of extending such service will not have an undue burden on other customers. In determining whether the expenditure for gas service is economically feasible, CenterPoint Energy shall take into consideration the total cost of serving the applicant and the expected revenue from the applicant.[51]

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[50] New Mexico Gas Company, *Original Rule No. 16, Gas Line Extension Policy*, January 30, 2009.

[51] CenterPoint Energy, *Rates & Tariffs Minnesota: Gas Rate Book*, Section VI (4.04), February 2, 2009 at http://info.centerpointenergy.com/aboutus/Minnesota/pdf/section6_rules_and_regulations/4_gas_mains.pdf.

The difference between incremental revenues and incremental costs equates to the utility's distribution margins.[52] Incremental costs include non-gas costs, largely composed of capital expenditures for new lines. [53]

Some utilities use a net present value (NPV) test that subtracts the discounted costs of serving new customers from the expected discounted revenues. If the difference were positive, the utility would consider the line extension to be economical and a financially viable investment.

Other utilities use the internal rate of return (IRR) method for evaluating new lines. Firms across different industries commonly use the IRR method to evaluate the financial viability of investments. For gas-line extensions, utilities calculate the discount rate at which the present-value distribution margins equal the present value incremental costs.[54] The utility estimates the annual margins and costs over the service life of a new line or some other specified time. If the discount rate (i.e., the IRR) is greater than the utility's cost of capital[55] (frequently defined as the utility's authorized rate of return in the latest rate case), the utility would consider

[52] Contention over the measurement of distribution margins can stem from estimating (1) the level of consumption by new customers, (2) future base rates, (3) future costs in serving new customers, (4) the discount rate, and (5) the number of years to include in the calculation. Concerning the last factor, what should be the time horizon: the expected service life of new lines, or the first several years (e.g., ten) of new-customer connection? Utilities tend to prefer a shorter time horizon to reduce the risk of cost recovery. The estimated distribution margins for some utilities, as discussed later, determine credits to new customers for line-extension costs and the amount that goes into base rates.

[53] Annual line-extension costs include maintenance and other operating costs, depreciation, taxes, and debt. Increasing the number of customers is usually far more costly to a gas utility than growing throughput from existing customers. The latter outcome, when it occurs between rate cases, normally increases a utility's profits, assuming that the utility base rates are above short-run marginal cost (which is typically true). Increasing the number of customers normally requires the utility to incur greater additional cost, especially if it has to build both new main and service lines. One study for a gas utility showed that a 1 percent increase in the number of customers raised cost by 0.71 percent. In comparison, a 1 percent growth in total retail deliveries from existing customers raised cost by about 0.11 percent. (Mark Newton Lowry, et al., *Statistical Analysis of Public Service of Colorado's Forward Test Year Proposal*, Exhibit No. MNL-1, December 17, 2010, 18 at http://xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/Exhibit_No._MNL-1.pdf.)

[54] Analysts sometimes refer to the IRR as the rate of return that makes the net present value of all cash flows (both inflow and outflow) for a particular project equal to zero.

[55] The cost of capital corresponds to the minimum acceptable rate of return. When the IRR exceeds the firm's cost of capital, the firm's value normally increases because the investment would be economically profitable.

the new line economically feasible.[56] Otherwise, the utility would have to decide whether to invest in a new line or invest under the condition that new customers will compensate for any revenue shortfall. For the latter action, the utility could calculate the customer contributions required to increase the IRR to the utility's cost of capital.[57]

A third group of utilities uses what analysts call a perpetual net present value method. The maximum level of "economical" investment equals the annual distribution margin divided by the required rate of return. The assumption is that the recovery period approaches infinity. If, for example, the average new customer contributes $300 annually to the utility's distribution margin and the utility's required rate of return is 10 percent, the utility would consider spending $3,000 per new customer to be economical. A real-world example of this method is the provision in NorthWestern Energy's (Nebraska) tariff:

> For determining contributions on pipeline projects, annual revenue will be determined by multiplying projected volumes by the projected tariff delivery rate. The annual non-PGA, non-surcharge revenues will be reduced by the annual projected Operating, Maintenance, and Property Tax expenses. The resulting net margin will be divided by the result of the current allowed return on rate base, grossed up for taxes, to determine the level of investment the load will support. Any project costs over and above the determined level of investment may be collected from the customer.[58]

Other utilities use different methods. Some utilities calculate the maximum investment cost for new lines as a specified multiple of estimated annual net revenues, or distribution margins.[59] In effect, the utility designates a minimum payback period. Assume that a utility

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[56] This condition is necessary for the utility to make the investment, but it may not constitute a sufficient condition. The utility, for example, might have limited capital funds for which it can garner a higher rate of return from other investments.

[57] One gas utility, Southwest Gas, uses a variant of the IRR method, called the incremental contribution method (ICM). As stated in its tariffs:

> The ICM is a cost of service analysis used to calculate the expected rate of return on an investment in mains and/or services and related facilities…If the ICM analysis results show a rate of return equal to or greater than the overall rate of return authorized by the Commission in the Company's most recent general rate case, the allowable investment is equal to the cost of the incremental investment.

(Southwest Gas Corporation, *Nevada Gas Tariff No.7*, Rule 9 (Facilities Extensions), August 10, 2011 at http://www.swgas.com/tariffs/nvtariff/rules/rule9.pdf.)

[58] NorthWestern Energy, *Nebraska Natural Gas Rate Schedules*, November 2012.

[59] The author obtained results, in Excel spreadsheet format, from an American Gas Association (AGA) survey showing that about half of the gas utilities reporting (47 utilities) use a simple revenue test

wants the payback period not to exceed five years and estimates the annual net revenue for a particular customer as $400. The utility would then consider $2,000 ($400·5) to be the threshold level of investment, or the maximum amount it will spend to justify the investment economically.

One innovative approach proposed by the Massachusetts Attorney General involves a utility conducting an "open season" during which prospective customers would commit to installing natural gas equipment. The utility would calculate the required customer contribution to justify new lines. It would then estimate the minimum number of customers it needs to sign up. If the utility achieves that number, it could then start building new lines. [60] A real-world example is a homeowner's association on the outskirts of Santa Fe, New Mexico, working with the local gas utility, New Mexico Gas Company, "to bring natural gas to as many homes in [the] neighborhood as possible." In a letter to residents, the association organizer noted, "[We] need to ascertain the level of willingness to pay for this project before we take any further steps." [61]

All of the above-mentioned tests have a narrow focus, namely, the financial effect on the utility. They exclude the public benefits that might derive from switching to natural gas. The tests are analogous to what analysts call the "utility test" for evaluating energy-efficiency initiatives. While comparing revenue changes and cost changes is important for knowing the effect on a utility, it ignores the broader societal effects. For fuel switching, these effects can include economic development, a cleaner environment, and increased energy reliability.

3. Extending lines before demand evolves

A gas utility typically would invest in new lines only when enough new customers commit to make them economically feasible, or when they agree to contribute the amount of dollars needed to compensate for any revenue shortfalls. One question that has cropped up recently is whether a utility should "build out" its distribution system on a scheduled basis prior to prospective customers making commitments to switch to natural gas.[62] The idea is to allow

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(e.g., comparing the net revenues from new customers with the line extension costs) while most of the others calculate the rate of return earned from line extensions. The author thanks AGA for providing this information.

[60] *See* Massachusetts Department of Public Utilities, *Petition of Bay State Gas Company, d/b/a Columbia Gas of Massachusetts, pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of a General Increase in Gas Distribution Rates Proposed in Tariffs M.D.P.U. Nos. 105 through 139*, D.P.U. 12-25, Order, November 1, 2012, 373-4.

[61] Tano Road Association, "Get Connected! Natural Gas Availability on Tano Road," May 2012 at http://tanoroad.org/news/natural-gas-project.

[62] Some gas utilities require new customers to identify the natural gas appliances and equipment they will use. In some instances, when customers report that they will use relatively little gas (e.g., less than 60 percent of the gas consumed by the average customer), the utility will require them to make a larger up-front contribution or advance.

demand to grow into the additional pipes. The utility may decide to move into new areas with high growth potential, independent of the immediate demand for natural gas service.[63] What would be the appropriate economic test to apply in this situation? For example, a utility may decide to invest in a new franchise area with the expectation that "we will build it and they will come." The uncertainty over future revenues and customer signups would make this endeavor risky. Expanding service in a new area, for example, poses risks in not knowing the number of interested customers: The utility could experience a slower-than-expected penetration of new customers.

One scenario is a utility's building out with the expectation that eventually enough new customers will sign up to gas service, but in the end, few customers do. Either the new customers will pay a high up-front charge that may make switching to natural gas uneconomical *ex post* or, if subsidized by existing utility customers or taxpayers, these parties will realize fewer benefits than anticipated because of the disappointing number of new gas customers.

In evaluating a build-out proposal, a commission may want the utility to provide an estimate of the number of new customers that are "reasonably expected to connect." This would help mitigate the likelihood of inefficient investments included in rate base.[64]

One utility, Northeast Utilities (NU) in Connecticut, proposed to expand its gas distribution system to underserved areas as part of the state's energy strategy. It estimated that the build-out of its system would cost $2.5 billion. As expressed in an article:

> In NU's plan to build-out the system, current natural gas customers will shoulder an extra cost in their bills of constructing and maintaining an infrastructure that will be underutilized while heating oil and electric-heat customers slowly make the switch to natural gas. The company also wants the state government to cover some of the cost for customers to make the conversion to natural gas.[65]

One policy question for utility commissions is: Should the utility absorb the entire risk, or should it pass at least a portion of the costs to existing customers? The rationale for the latter action could be that existing customers will benefit once new customers commit to future gas service. A commission should ask whether such cost recovery is really a good deal for existing customers. Perhaps the local or state government should bolster support by issuing bonds or

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[63] Sometimes a gas utility would expand its mains to a large customer and then gradually, over time, add small customers located along them.

[64] This mitigation presumes that existing customers, rather than utility shareholders, bear the risk of a lower-than-expected number of new customers signing up for natural gas service.

[65] Brad Kane, "Merged NU Pushing $2.5 B Natural Gas Build-Out," *HartfordBusiness.com*, May 21, 2012 at http://www.hartfordbusiness.com/apps/pbcs.dll/article?AID=/20120521/PRINTEDITION/305219998/0/moversshakers.

providing other financial assistance to utility infrastructure development. Because state utility commissions can expect the demand for gas service in sparsely populated areas to grow in the future, they should consider revisiting their line-extension rules to address system build-out.

4. How to apply an economic test

A final point relates to how a utility should use an economic test for decision making: Should it use the test absolutely in accepting or rejecting a proposed line extension? Should a utility, instead, use the test as a guide for action? For example, the test would constitute only one piece of information available to the utility in deciding whether to build new lines.

Gas utilities have used the economic test to calculate the maximum investment that they could support given the expected distribution margins from new lines. The difference between actual cost and economical cost usually would fall on new customers. A good example is the tariff of one Arkansas utility, CenterPoint Enegry:

> If it is determined that the Company's return on investment (ROI) on the proposed main extension will equal or exceed the Company's cost of funding capital projects, the extension will be made at no cost to the customer. If it is determined that the Company's ROI will be less than the Company's cost of funding capital projects, the customer shall be required to pay an amount sufficient to ensure that the Company is able to earn an ROI equal to its cost of funding capital projects.[66]

D. Utility incentives for extending lines

Because line extensions mainly involve capital expenditures, the most crucial outcome for a utility is to expect to earn its authorized rate of return. State utility commissions would tend to agree with this goal. Yet their duty to utility consumers and the public interest also includes making sure that this outcome does not violate generally accepted fairness and economic-efficiency standards.

With new revenues over time, a utility should benefit as long as it recovers its costs.[67] The utility would want to minimize its risk by maximizing the probability of cost recovery.

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[66] CenterPoint Energy, *Rates & Tariffs Arkansas: Gas Rate Book,* Part III – Rate Schedule No. 7 (Extension of Facilities), September 25, 2007 at http://info.centerpointenergy.com/aboutus/arkansas/pdf/Rate_Schedules/ExtensionFacilities.pdf.

[67] *See*, for example, the statement of the Massachusetts Department of Public Utilities:

> The Department's ratemaking treatment for incremental revenues from new customers allow a company to retain those revenues between rate cases…The requirement that incremental revenues from new customers exceed the incremental cost of the capital investment, including a threshold return on the incremental investment that exceeds the Company's overall rate of return, provides gas companies with the incentive to expand their distribution network.

Some utilities seem to prefer recovering more of the incremental costs from existing customers. Their thinking seems to be that recovering costs from only new customers would jeopardize the level of fuel switching or increase the risk of non-recovery.

Do utilities have the right incentive to invest in new lines? That is a difficult question to answer. Utilities generally find it attractive to increase the number of customers. After all, with more customers, their revenues and profits inevitably increase in the end.[68] Yet they may fear non-recovery of all of their incremental costs for line extensions. For example, regulators might set a cap on cost recovery from new customers based on actual revenues that turn out to be lower than expected, or based on erroneously projected capital expenditures. Consequently, utilities might be content with serving fewer customers but assured of full cost recovery. We observe varying utility dispositions to promote fuel switching, presumably reflecting different risk profiles or assessments of likely full cost recovery.

Regulatory lag may be another factor affecting a utility's motivation to expand its service. When a utility receives prompt cost recovery—for example, through a surcharge rider—and retains the profits from serving new customers until the next rate case, the utility would likely exhibit more proactive behavior in extending its lines.

E. "Free" line extensions

Several gas utilities, on a limited basis, provide new customers with line extensions at no cost. Based on a survey that the author obtained from AGA, 49 out of the 83 gas utilities reported that they offer limited free line extensions. Industry observers often refer to the "no cost" pipes as allowances in the form of a dollar credit toward the new customer's financial obligation for a line extension. Utilities may specify the number of "free feet," fixed dollars of "free" pipes, or the maximum dollars of "free" line extensions based on a formula that considers

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(Massachusetts Department of Public Utilities, *Petition of Bay State Gas Company, d/b/a Columbia Gas of Massachusetts, pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of a General Increase in Gas Distribution Rates Proposed in Tariffs M.D.P.U. Nos. 105 through 139*, D.P.U. 12-25, Order, 381.)

[68] A gas utility typically recovers non-gas costs from customers by charging them a fixed monthly customer charge plus a volumetric or usage charge. The utility recovers a portion of its fixed costs (i.e., costs that do not vary with customer usage, at least in the short run) through a volumetric charge. Thus, the utility's ability to recover its authorized rate of return depends on the level of gas sales. The utility would have an incentive to promote gas sales, as long as additional sales increase revenues by more than costs. This is why a utility would benefit from increasing sales.

estimated usage.[69] The dollar value often represents the distribution margins that the utility expects to earn from a new customer over some specified time.[70]

The dollar amount of the "free" extension generally goes into the utility's rate base. Thus, all ratepayers initially fund the "free" pipe with payback over time from the distribution margins earned by the utility from new customers. These margins would tend to lower future rates for existing customers based on rate-of-return ratemaking.[71] In effect, existing customers are providing a loan to new customers who pay back through their monthly gas bills. Giving new customers credits toward their financial obligations attempts to balance their interests with the interests of existing customers and utility shareholders.

In its decision approving various line-extension rules for gas and electric utilities, the California Public Utilities Commission discussed the rationale for revenue-based allowances:

> Revenue-based allowances (supported by applicant revenues) for both gas and electric line extensions provide an equitable arrangement between the applicant and ratepayer, as well as between various classes of applicants. The revenue-based allowances, which represent the utility investment, are based on then expected supporting revenues from the loads to be served by the extension. This amount is then used as the allowance and is credited to the applicant's total cost for the extension. The allowance is stated in dollars in order to maintain consistency among and between a large variety of applicants.[72]

F. Customer contributions

Utilities construct new lines at a cost that often exceeds their net present value. To avoid causing existing customers, as well as utility shareholders, to subsidize new customers, a utility will impose a separate charge on a new customer. New customers in a sparsely populated area may produce additional revenues for the utility that are far below the cost of extension. The utility may calculate the difference and charge it to new customers.[73] Industry observers refer to

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[69] Someone has to pay for the "free" pipes, so their costs just pass to someone else, namely, utility shareholders or existing customers.

[70] To hold the utility's existing customers harmless, the allowance should not exceed the discounted expected value of the distribution margins from new customers.

[71] Even by paying higher rates in the short term, existing customers should pay lower rates over time as new customers contribute toward the utility's distribution margins. In this sense, existing customers are not subsidizing new customers.

[72] California Public Utilities Commission, *RE Line Extension Rules of Electric and Gas Utilities*, D.94-12-026, 58 CPUC2d 1, 73, n.2.

[73] An alternative to this approach, which apparently few if any utilities follow, is to assign responsibility for the shortfall to utility shareholders. As new customers connect to a new main line, the

these charges as customer advances for construction,[74] or contributions in aid of construction (CIAC).[75] Utilities do not rate base these charges, but the Internal Revenue Service treats CIAC as revenue for tax purposes.[76]

A separate charge presumes that new customers value switching to natural gas more than what they pay for gas service under the utility's rates. In economics jargon, they receive a consumer surplus, defined as the difference between the value that they place on a good or service and the amount that they actually pay. Thus, new customers could pay an additional charge and still realize a net benefit from converting to gas. Nevertheless, a large up-front charge may discourage them from switching to gas, even if they benefit in the end.

To elaborate, one policy concern is that customer contribution could be so high that some prospective customers would decide not to switch to natural gas even when it is cost-beneficial from a lifecycle perspective.[77] This trade-off between maximizing economical fuel switching and holding new customers responsible for the incremental costs is a matter that will likely confront state commissions in the future. A utility, for example, may require a new customer to pay $15,000 up front to cover her portion of new service and main lines. As an alternative, and

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utility could add more of the costs for line extensions to its rate base. The utility would assume more of the risk but in the process could achieve greater profits in the end from a higher rate base. Overall, this approach might better motivate the utility to increase the number of new customers on new main lines.

[74] Customer advances are funds deposited with the utility as a refundable advance for the customer's share of a line extension determined by the utility to cover that portion of the extension not economically feasible. Refunds may be partial or full over a designated period.

[75] CIAC are funds deposited with the utility as a non-refundable contribution to assist in the financing of a line extension. As with customer advances, the utility calculates CIAC based on "excess" cost" relative to the projected revenues received from new customers. Depending on the utility, new customers may be able to pay their share of CIAC over some designated period. CIAC reflects the need to charge certain customers a special fee when they demand unusual service or reside in an area remote from the utility's infrastructure.

[76] This fact leads to the observation that a utility would have a financial incentive to minimize the CIAC charged to new customers by placing more of the line expansion costs in rate base. The utility would then earn a higher profit, but the downside is that existing customers end up paying a higher share of the line expansion costs.

[77] Another concern raised in regulatory proceedings is that the utility overstates the CIAC. For example, new customers could increase the utilization of a utility's internal resources, thereby benefiting existing customers by lowering average cost. As the argument goes, this cost improvement should translate into a lower CIAC obligation for new customers. *See* Massachusetts Attorney General, *Initial Brief of the Attorney General, Petition of Bay State Gas Company, d/b/a Columbia Gas of Massachusetts, pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of a General Increase in Gas Distribution Rates Proposed in Tariffs M.D.P.U. Nos. 105 through 13,* D.P.U. 12-25, August 21, 2012.

what some utilities allow, the customer could pay back her contribution over a number of years. The utility could collect the contribution through a special surcharge. The surcharge could be a CIAC or incorporated into rates. By spreading the customer contribution over, say, five years, customers would be more inclined to switch.[78] One question relates to the appropriate payback period for customer contributions. Extending the period over too many years can impose unnecessary risk on the utility in recovering its costs. Perhaps the threshold for determining the payback period should be whether the monthly contribution is lower than the monthly energy savings for a new customer. If it were, the new customer would still benefit from switching to natural gas.

G. Effect on existing customers: rolled-in versus incremental pricing

1. No-burden criterion

A common objective of line extension rules is to hold existing customers harmless. That is, utilities apply what economists call a "burden test" to protect existing customers. That is why, for example, rules require new customer contributions and economic tests[79] for assessing proposals for line extensions. As a rule, when a utility receives revenues from new customers equal to or greater than the incremental cost, existing customers are either no worse off or better off. The revenues from new customers can filter through rates and a separate surcharge (*see* the previous section).

The addition of new customers, at least in theory, can benefit existing customers. A concept called economies of scope says that by providing another service—for example, service to new customers—a firm might more efficiently use its internal resources. As an illustration, with added customers, a utility might lower its average cost for IT activities, general personnel, billing, and metering. The result is a lowering of the utility's average cost, which benefits all customers, both new and existing.[80]

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[78] In Minnesota, some gas utilities have what they call a New Area Surcharge (NAS) for new customers in locations previously unserved. They calculate the yearly surcharge as the prevent value of the annual difference between the capital and operating costs of the line extension, and the non-gas revenues. The utilities treat the surcharge as a CIAC for both accounting and ratemaking purposes. One reason for this treatment is that the surcharge would more directly track the extension costs. NAS applies only to previously unserved areas that cannot support economically a line extension under the utility's tariffs.

[79] By failing an economic test, a line-extension project is not feasible, justifying a separate advance or contribution from new customers. Feasibility, in generic terms, means that the expected distribution margins from new customers would support the incremental costs from constructing new lines.

[80] It would be wrong to infer that line extensions to serve new customers create the same economies as building lines to increase system reliability, access new gas supplies, or provide

2. Economies of scope, incremental prices, and rolled-in prices

This section explores the relationship between economies of scope and price limits on service to both existing and new customers. It also provides a formal definition of cross-subsidization, which links to the regulatory concept of undue price discrimination. Finally, this section addresses "fairness" from the angle of cost allocation.

a. "Acceptable" pricing limits

Formally, economies of scope derive from the following relationships:

$$IC_{NC} = C(NC,EC) - C(0,EC),$$

where the incremental cost in serving new customers (IC_{NC}) equals the utility's cost in serving both new and existing customers [C(NC,EC)] minus the utility's cost in serving only existing customers [C(0,EC)].[81] Economists call this last term the "stand-alone cost of serving only existing customers." We will refer to this cost as SAC_{EC}.

In the absence of economies of scope, the incremental cost of serving new customers equals

$$IC'_{NC} = C(NC,0) = SAC_{NC},$$

where the incremental cost (IC'_{NC}) equals the utility's cost in serving new customers alone [C(NC,0).], which is the stand-alone cost (SAC_{NC}).

In the presence of economies of scope, the following relationship holds:

$$C(NC,EC) < C(NC,0) + C(0,EC) = SAC_{NC} + SAC_{EC}.$$

Assume that the utility's cost in serving new customers alone is $12 million ($SAC_{NC}$), in serving existing customers alone is $100 million ($SAC_{EC}$), and in serving both groups of customers collectively is $110 million [C(NC,EC)]. The benefit to new customers from the utility's serving existing customers simultaneously is $2 million; that is, the difference between the cost of serving new customers alone ($12 million, or SAC_{NC}) and the cost of serving new customers when the utility is serving existing customers ($10 million, or IC_{NC}).[82] The $2 million are the

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interconnections. We should expect the system benefits from the line extensions to serve new customers to be much smaller and ostensibly marginal.

[81] NC denotes new customers and EC existing customers.

[82] The incremental cost of serving existing customers, assuming that the utility previously served new customers, is C(NC,EC) – C(NC,0). We are now reversing the definition of "new customers" to include the previous existing customers and the existing customers to include the previous new customers. The amount equals $110 million - $12 million, or $98 million.

benefits from economies of scope. This illustration shows how serving both groups of customers simultaneously can benefit new customers.

Similarly, we can show that economies of scope can benefit existing customers as well. Assume that existing and new customers consume, on average, the same quantity of gas. In our example, the total cost for the utility increases by 10 percent (from $100 million to $110 million) when the utility serves new customers. Assume also that the stand-alone cost per existing or new customer is the same. New customers would then grow the utility's sales by 12 percent and reduce the utility's average cost by roughly 2 percent.[83] Thus, rates to existing customers would tend to decrease.

By definition, economies of scope measure the difference between the sum of the cost for serving existing and new customers separately and serving them simultaneously. We assume that serving one group of customers is distinct from serving the other group. As long as the utility recovers from new customers sufficient revenues to cover the incremental costs, no burden falls on existing customers. From the perspective of existing customers, the prices are compensatory.

In the above example, if the utility charges new customers $8 million (below the incremental cost), existing customers are worse off by $2 million. Whereas prior to new customers existing customers were paying $100 million, now they are paying $102 million for the same service ($110 million - $8 million). We can say that existing customers are cross-subsidizing new customers. Cross-subsidization, according to economists, occurs whenever a utility charges any individual service or customer class more than its stand-alone cost. When the utility charges a particular service or group of customers more than the stand-alone cost, it is necessarily charging another service or group of customers less than the incremental cost. This outcome constitutes a cross-subsidy. Many economists have argued that a utility should not charge more for any service or customer than the stand-alone cost, on grounds of both "fairness" and economic efficiency.

If instead the utility recovers more than incremental costs from new customers—say, $14 million—existing customers are better off by $4 million,[84] but new customers are cross-subsidizing existing customers. The reason is that new customers are paying more than their stand-alone cost, which, as we assumed earlier, is $12 million.[85] This outcome means that new

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[83] As assumed earlier, the stand-alone costs for new customers and existing customers are $12 million and $100 million, respectively.

[84] Existing customers now pay $96 million, a decrease of $4 million from what they previously paid for the same service.

[85] Charging above incremental cost does not always result in a cross-subsidy. If the utility charges new customers $11 million, they are paying more than their incremental cost ($10 million) but less than their stand-alone cost ($12 million).

customers would be better off if the utility only served them and not existing customers.[86] In sum, prices violate a fairness standard whenever a customer class or service pays more than its stand-alone cost.[87] That statement presumes that regulators associate unfairness with a cross-subsidy.

For cross-subsidization not to occur, the total costs allocated to (1) existing customers cannot exceed $100 million and (2) new customers cannot exceed $12 million. Otherwise, each group of customers would be better off without the other. As long as the utility recovers sufficient revenues from each group to cover the group's incremental cost, each group benefits from the presence of the other. That is, each group is paying less than the stand-alone cost for that group. This outcome mimics the operation of a well-functioning competitive market. One implication is that existing customers are better off, or at least not worse off, when the utility charges new customers at least the incremental cost of serving them.[88]

b. What is fair?

The utility charging the incremental cost for each group of customers might pose a "fairness" problem. In our example, the sum of the incremental cost for both customers, $108 million,[89] falls short of the utility's total cost of $110 million.[90] The shortfall comes from the

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[86] Although it would be difficult to measure stand-alone cost, the condition that no customer pays more than this cost hinges on two reasonably measurable outcomes: (a) the utility's revenues equal its total cost and (b) all customers at least pay the incremental cost of serving them. Thus, no customer is paying more than the stand-alone cost when the utility earns normal profits, and no cross-subsidy exists.

[87] As noted by one economist:

> The stand-alone cost concept is equivalent to the game theoretic concept of an imputation that lies in the core of a "cost-sharing game," requiring each subset of members of a coalition to receive as a result of their membership a payoff at least as large as they could obtain for themselves if they were to leave the coalition and fend entirely for themselves.

(William J. Baumol, *Superfairness: Applications and Theory* (Cambridge, MA: The MIT Press, 1987), 121.)

[88] Another way of expressing this idea is that as long as the revenues received from existing customers are below their stand-alone cost, assuming the utility earns a normal profit, the utility is collecting more than the incremental cost from new customers. In our example, assume that the utility charges new customers $12 million, which is $2 million more than the incremental cost of serving new customers. With a total cost of $110 million, the costs allocated to existing customers are $98 million. This amount is $2 million below what existing customers would have had to pay without the new customers (i.e., SAC_{EC}).

[89] We calculated, above, the incremental cost of new customers as $10 million and the incremental cost of existing customers as $98 million.

missing $2 million that derives from common or shared costs.[91] How then should the utility assign responsibility for the shortfall of $2 million between the two groups of customers? If the utility decides, for example, to charge new customers the incremental cost of $10 million, existing customers would pay $100 million, as they did prior to the utility's signing up new customers.[92] This outcome, at first sight, seems reasonable in not burdening existing customers. Yet all of the benefits from economies of scope would transfer to new customers, a situation that some regulators might consider unfair.[93]

Whereas previously we defined fairness in terms of a cross-subsidy, we now apply a less rigorous test. Charging new customers more than the incremental cost may be fairer, if not the most economically efficient action. While in this example, no customer group receives a cross-subsidy, regulators could determine that the benefits from more efficient operations (i.e., economies of scope) should more evenly pass down to both customer groups. Cost allocation inevitably comes down to the regulators' judgment in weighing and trading-off different societal objectives.[94] If economic efficiency is one objective, and weighed heavily, regulators would tend to allocate more of the common costs to customers with the lowest price elasticity of demand. Applying in our example what economists call the Ramsey or second-best pricing rule, existing customers would seem to bear disproportionately those costs.[95] In sum, even when

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[90] Assuming that the utility earns a normal profit, it should collect enough revenues from both groups of customers collectively to cover C(NC,EC), or $110 million.

[91] These costs occur when the utility uses the same input or resources to serve both existing customers and new customers. The shared nature of these inputs means that it becomes impossible to assign them unambiguously to each customer group.

[92] One can show that the total cost of serving existing customers and new customers together is the sum of the stand-alone cost of serving existing customers and the incremental cost of serving new customers.

[93] Utilities might find this outcome favorable to their interests, as they would have the tendency to keep down the cost burden to new customers relative to existing customers. The reason is that existing customers are more captive and, therefore, less responsive to price. (*See* a fuller discussion in the next section.)

[94] Some economists would label this subjective cost allocation as arbitrary. It seems, however, that because regulators have an obligation to allow utilities an opportunity to earn a reasonable rate of return, they have no choice but to use their judgment, especially in spreading common and joint costs across different customers and services. Common costs, for example, are costs incurred jointly for two or more types of operation or the provision of two or more services. They include the capital cost of a new distribution main serving residential, commercial, and industrial customers.

[95] Ramsey pricing maximizes social welfare, given a revenue-requirement constraint. Specifically, it says that when setting prices equal to marginal or incremental cost fails to produce sufficient revenues for the utility, regulators should adjust rates to minimize efficiency losses. The way to achieve this outcome is to increase rates the most for those services or customers exhibiting the lowest price elasticities of demand. As we discussed earlier, existing customers likely would have a lower price

applying incremental-pricing principles, because of the traditional-ratemaking objective to set revenues equal to a utility's total costs, regulators must grapple, in the absence of an objective standard, with how to allocate a portion of the utility's costs among customers and services.

H. Cost recovery for a utility

Two policy questions relate to (1) how the utility should recover its incremental costs from new customers and existing customers, and (2) over what period the utility should recover those costs. One answer is that new customers should bear all of the incremental costs. Otherwise, existing customers would be worse off, as shown in the previous section. Besides, new customers are already benefiting from joining the utility system, assuming the presence of economies of scope. One exception occurs when existing customers benefit indirectly—say, from cleaner air or economic development. Other than that, for both economic-efficiency and equity reasons, existing customers should not have to bear any of the incremental costs.

Gas utilities would have an inclination toward shifting some of the incremental costs to existing customers. Charging those customers a slightly higher rate would likely have little effect on their gas consumption. Some prospective customers, on the other hand, may forgo switching to natural gas if they have to pay the full incremental cost. Cost allocation to existing customers in this instance would constitute price discrimination.[96]

The timing and likelihood of cost recovery can affect a utility's incentive to invest in new lines (*see* Part III.D). Specifically, more prompt and certain cost recovery would heighten a utility's motivation to add new customers. Mitigating regulatory lag by allowing a utility to recover capital expenditures on a periodic basis outside of a rate case would improve financial certainty for the utility. The regulator should assure ratepayers that any costs passed through are prudent and reflective of good utility management.[97] Did the utility, for example, spend the

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elasticity than prospective customers, who are contemplating fuel switching. Yet whether this pricing rule is fair, or at least fairer than other rules that violate efficiency conditions, lacks any objective evidence. Some readers might argue that the Ramsey pricing rule is unfair because it would increase prices more to "captive" customers. According to this view, there is an inevitable conflict between achieving both efficiency and fairness goals.

[96] Discriminatory pricing generally occurs when price differences for the same service do not correspond to cost differences. Discriminatory pricing considers customers' willingness to pay, which depends on the ability of customers to find alternative suppliers or to engage in self-supply. Prospective customers, by definition, can choose between remaining with their current energy source or switching to natural gas. Existing customers are less likely to respond to a higher price by switching to another energy source. A utility may have to offer prospective customers a rate below incremental cost to entice them to convert to natural gas. Yet, as discussed earlier, such a rate can burden existing customers and diminish economic efficiency.

[97] *See*, for example, Ken Costello, *How Should Regulators View Cost Trackers?* NRRI 09-13, September 2009, at http://nrri.org/pubs/gas/NRRI_cost_trackers_sept09-13.pdf. The paper points out that cost trackers or riders for which relevant costs do not undergo a thorough review by the regulator can

minimum amount on constructing new service and main lines? Were the capital expenditures justified based on a sound economic test for assessing new lines?

I. Ratemaking treatment of incremental costs

1. Challenges for regulators

Line extensions pose special problems for commissions for pricing and charging new customers for the additional costs:

- What are the proper principles for pricing utility service for new customers?
- Should a utility, for example, use rolled-in pricing or incremental pricing for setting prices to new customers?
- Should a utility charge new customers an additional amount that falls outside the tariff?
- If so, how should the utility determine the size and method of new-customer contribution?

We have already addressed most of these questions. One important policy question relates to how a utility can expand its service without cross-subsidization between customer classes, and between existing and new customers. The outcome would have both equity and economic-efficiency implications. Under strict rolled-in pricing, all customers pay for the incremental costs of new lines. Supporters of this pricing argue that existing customers pay for only the service they receive; they have no entitlement to continue using old pipes at the same (or depreciated) cost irrespective of new circumstances. Charging new customers a higher rate, under this principle, would be discriminatory: New customers would pay higher rates just because they initiate service at a later date. All customers—existing and new—should pay the same price for utility service.[98] On the opposite side are advocates of incremental pricing who argue that rolled-in pricing is economically inefficient and results in the subsidization of new gas lines: Prospective customers receive the wrong price signals, and other fuels face a competitive disadvantage.

2. Options for ratemaking

A utility has different options on how to recover its costs for line extensions. It can impose a surcharge on new customers corresponding to the “excess” costs not incorporated into

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weaken a utility’s incentive to control those costs. They can also diminish the effect of regulatory lag on a utility’s cost performance.

[98] Unlike most utilities’ tariff rules, new customers would not face a special surcharge or pay extra for “excess” costs in some other way.

base rates. A utility also can create a special rider or cost tracker that recovers costs periodically outside a rate case. The utility may apply the rider only to new customers or to all of its customers. The utility can also increase the customer charge to account for investments in new lines. As a rule, a utility would include those capital investments for new lines that pass the economic test in rate base.

3. Rolled-in versus incremental pricing

Regulators generally approve rolled-in pricing when a new investment stands to benefit all customers, or when demand by all customers creates the need to increase system capacity. It would be wrong to infer that rolled-in pricing is inherently discriminatory, unfair, and economically inefficient. As argued in Part III.G of this paper, its appropriateness depends on the specific circumstances. One example is a gas utility investing in new storage capability to meet the growing demand of its customers. Because the investment would benefit all customers, it would be appropriate to roll-in the costs into the rates of all customers. They would then be responsible for paying the costs for this investment. When new customers require the utility to build lines dedicated to serving them,[99] rolled-in pricing becomes less defensible, especially if the benefits to existing customers are less than their share of the costs they bear. Analysts would contend that in this instance new customers would receive a subsidy at the expense of existing customers. Unless the utility can argue that in some way it built a new line because of the demand for gas services by existing customers, incremental pricing would be both economically efficient and fair.

The reader may ask why new customers should pay more for the same gas service than existing customers do. Does this not represent "vintage pricing," which economists have long criticized for its unfairness and inefficiency? In the context of gas-line extension, a utility expands its lines strictly to accommodate new customers. Existing customers are not signaling to the utility that it should invest in new lines. They would not pay for the gas-line extensions at any price. Charging incremental rates in this example would be consistent with the cost-causality principle, which is a tenet of good utility pricing.[100] Cost causality has no connection to vintage pricing, however. Vintage pricing, in which later customers pay more than other customers, is both unfair and economically inefficient when departing from cost-causality principles. New utility customers should pay more than existing customers because they alone require the utility to incur additional cost for new pipes. If new customers do not require other than incidental costs for the utility, prices to both new and existing customers should be similar. In this instance, charging new customers a higher price for the same service would be unfair.

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[99] The beneficiaries are easily identifiable.

[100] It would also be incompatible with the principle that prices should relate to customers' willingness to pay for a service or good. If existing customers place no value on line extensions to serve new customers, they should not have to pay anything for them.

Pricing utility service to new customers below incremental cost produces negative outcomes. First, new customers see improper price signals that can result in excessive fuel switching to natural gas. Second, this price places other fuels at a competitive disadvantage. Third, existing customers are worse off. The presence of new customers, in fact, raises the rates of existing customers, thereby failing the "burden test." Another way to restate this outcome is that existing customers would be better off without the new customers on the utility system. Pricing below incremental cost essentially increases rates for existing customers at the benefit of new customers.

Some utilities spend money for marketing and outreach programs to promote fuel switching. A few offer loans and other financial assistance to new customers. Others provide management support for facilitating fuel switching. This function would lower the transaction cost for energy consumers to switch to natural gas. If regulators feel these activities would benefit existing customers, they may allow the utility to pass their costs to them. Otherwise, if regulators view these activities as promotional in nature, they may decide to have utility shareholders or new customers pay for them.

J. Subsidization of new customers: When is it justified?

1. Public benefits

When benefits from line extensions extend beyond those received directly by fuel-switching consumers (i.e., public benefits exceed private benefits), regulators should ask whether it is appropriate to spread the costs to all customers. Assume that a line extension ultimately connecting 2,000 customers could produce a cleaner environment and less dependency on foreign oil. Regulators might approve the utility's recovering from all customers the costs associated with the line extension. Yet if fuel-switching customers alone stand to benefit, no costs should fall on the general ratepayer. The rule here is that growth should pay for itself by requiring new customers to pay the full costs for extending service to their areas.

2. The special case of line extensions in remote areas

Another seemingly defensible reason for a subsidy is that in some unserved remote areas, constructing new lines would be unprofitable to the utility or unaffordable to new customers. From a lifecycle perspective, new customers may be willing to pay the utility enough through rates and special surcharges to make it profitable for the utility.

As an example, assume that the present value benefit to new customers from switching to gas is $2 million. Assume also that the utility requires $1.5 million in revenues, whether from their normal rates or a special upfront customer contribution, to consider the new line adequately profitable or financially neutral. It would then appear that both new customers and the utility would be better off with the line extension: The customer could pay the utility enough for the line extension to make the investment both profitable for the utility and beneficial to her in the long term. What could hinder the building of the new line? One obstacle could be that the required advanced customer contribution might pose an obstacle for new customers. Given the expected revenues for the utility and the line cost, the average advanced contribution per customer might come to, say, $10,000. Just like other investments that payoff in the end, consumers may forgo them because of the high initial cost.[101] Many households, for example, may decide they cannot afford to take $10,000 from their savings at this time, or take out a loan of that amount.[102]

Perhaps, then, just like subsidizing customers for energy-efficiency investments, the utility could have existing customers pay some portion of the advanced contributions. The utility could argue that fuel switching would be net beneficial but unaffordable to some prospective customers. Why not then increase slightly the rates of existing customers so that prospective customers would switch to natural gas? One answer is that it may be more appropriate for the government to provide financial assistance to new customers. Especially if the line extension contributes to economic development in the rural area, funding with taxpayer money might be the preferred course. Another answer is that, instead of charging existing customers a higher rate, the utility could think of creative ways for new customers to pay their advanced contribution in a more accommodating way. For example, the utility could allow new customers to pay back their special financial contribution over several years, lessening their immediate financial burden.

3. When a subsidy is bad policy

Some readers might conclude that the above example fails to justify a subsidy. Even if one agrees that a problem exists, the "subsidy" solution may be inferior to other actions. In other words, subsidization can represent a blunt and cost-inefficient response to achieve some social objective.

One seemingly preferred action would be for the utility to allow new customers to pay the $5,000 over a number of years. Prospective customers then might find switching to gas, which would be in their long-term interest, affordable. As a rule, efficient fuel switching requires that those who benefit pay the full cost of converting furnaces and other equipment, plus the new lines. Commissions and other policymakers should regard this outcome as the default solution, unless evidence supports some financial assistance from either existing customers or taxpayers. Thus, they should exercise caution in approving subsidies for customers who switch to natural gas. In the absence of large-scale public benefits or utility internal efficiencies, subsidies funded by a utility's existing customers come across as both unfair and economically inefficient:

1. It is unfair to existing customers because they are involuntarily funding new customers at no benefit or less-than-commensurate benefits to them.

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[101] One example that regulators can relate to is energy-efficiency investments.

[102] In today's tight credit market, households may find it difficult to get loan approval.

2. It is also economically inefficient if it induces additional energy consumers to switch to natural gas when they otherwise would not have if they had to pay the full cost of line extensions.

3. Subsidies also may distort competition among energy sources. By offering new gas customers subsidies, suppliers of oil, propane, and electricity would be at a disadvantage.

4. Even with public benefits, subsidies funded by existing customers might not constitute the most cost-effective approach for increasing the number of new gas customers and gas consumption. Funding from taxpayers or utility shareholders might create less inefficiency.

5. Even if policymakers can justify subsidies for fuel switching and line extensions, they need to ask which forms would be most cost-effective and create the least distortion.

Some readers may justify subsidies for fuel switching to natural gas similarly to the justifications used for governmental subsidies to rural electric cooperatives. Those subsidies assisted in the expansion of electric service to areas that privately owned utilities would not find financially viable. One difference is that rural people and businesses would not have access to electricity without the cooperatives. Yet prospective natural gas customers do have access to some other energy source (even if it is not their preferred source) to meet their demands. The main reason for switching would be to save money on energy, not to have available some new end-use service.

K. Role of local, regional, and state governments

Notwithstanding the previous section's discussion, some people would argue that the public benefits from fuel switching justify governmental assistance. These benefits are in addition to the benefits that energy consumers directly receive when they switch to natural gas. They include a cleaner environment, bolstering economic development, and national security. [103] A state can include as part of its energy strategy the promotion of customers switching to natural gas. The rationale for state financial assistance is that: (1) market forces are not accounting for the public benefits or (2) market barriers are stifling the amount of switching. Either condition may result in suboptimal levels of fuel switching.

[103] The positive effects, especially a cleaner environment and national security, apply more to switching from oil to natural gas. The environmental effects of propane are comparable to those for natural gas. When released into the atmosphere, and unlike natural gas, propane has no greenhouse gas effect. Domestic production accounts for about 98 percent of the propane consumed in the U.S., avoiding any national security problems.

1. Proactive states

Part II identified those states that have enacted special legislation, taken specific actions, or proposed actions, all with the intent to facilitate gas-line extensions. These states include Connecticut, Delaware, Maine, Nebraska, New York, North Carolina, Vermont, and Virginia. These actions mainly serve to remove barriers to fuel switching that originate on both the consumer and utility sides. All of these states presume potentially large benefits from energy consumers switching to natural gas.

2. General governmental actions

Justification for governmental assistance must rest on potentially large benefits from fuel switching to natural gas for a locality, region, or state. These benefits, although theoretically plausible, so far lack empirical support, at least in providing policymakers with reliable evidence that their magnitude is sufficient to warrant governmental actions.

Other than direct financial assistance, governments can take more incremental action by facilitating fuel switching through information dissemination and promotional practices. Government units can collaborate with utilities and consumers in developing proposals for the expansion of gas service. They can then present their proposals before the state utility commission or other pertinent entities for review and approval.

IV. Model of a Line-Extension Policy

A major goal of a line-extension policy is to achieve a proper balance of outcomes for the different stakeholders. Five conditions advance this goal:

- **Financially viability of the utility:** The utility recovers all of its incremental costs deemed prudent by the regulator.

- **Affordability of economical fuel switching to new customers:** New gas customers generally pay both conversion costs and at least a portion of line-extension costs. Even when fuel switching is economical, these two costs together can pose barriers to prospective customers. Payment plans or other schemes that help lift the immediate financial burden on new customers can make fuel switching more affordable.

- **Minimal negative effect on existing customers:** One outcome of a good policy is to prevent unduly burdening existing customers. Any rate increase to existing customers should be commensurate with the benefits they receive from the connection of new customers.

- **Level playing field for all energy sources:** By subsidizing customers who switch to natural gas, oil and propane suppliers face a disadvantage created by regulation. These suppliers may lose customers directly from gas utilities charging new customers below incremental cost for service connections.

- **Overall, balancing of regulatory goals as they relate to fairness, economic efficiency and other outcomes:** One feature of fairness is that all customers of similar characteristics receive the same treatment from the utility. Otherwise, the utility could discriminate among prospective customers based on their willingness to pay for switching to natural gas. The utility, for example, would have an incentive to charge a higher line extension cost to customers who stand to benefit the most from switching.

A. Regulatory objectives and options

Six regulatory objectives should underlie a line-extension policy. The major ones are fairness to all stakeholders and economic efficiency. The previous sections talked about them in some detail.

Table 1 lists different options for achieving the six objectives. A discussion of them follows.

1. Good utility incentives

Utilities should engage proactively in promoting fuel switching when in the public interest. The natural inclination of a utility would be to promote activities that add to their future revenues and profits. With an opportunity to profit and only moderate regulatory lag, and combined with certain cost recovery, the utility should welcome new customers. On the downside, a utility may fear the risk of less-than-full cost recovery.

One example of a proactive utility in expanding gas service is NSTAR in Massachusetts. It has an aggressive outreach and information program showing large benefits for energy consumers who switch from oil to natural gas. The utility calculates that even with high up-front costs for conversion (the sum of the cost for new heating equipment, new service connection, and new main extension), households can save on net by lowering their energy bill by an average $2,000 annually when they switch from oil to natural gas. The utility recognizes the importance of having financial arrangements in which consumers would pay the up-front costs over time rather than in one large lump sum (which NSTAR says could easily exceed $14,000).[104]

2. Good energy-consumer incentives to switch

Energy consumers should switch to natural gas when society saves enough in energy costs to justify the capital expenditures and other incremental costs associated with switching. Inertia, high up-front costs, lack of adequate information, and other reasons explain why energy consumers might not switch even when they gain economically. Energy consumers need to be well informed and face proper price signals. Subsidizing them excessively can motivate energy consumers to overinvest in switching by failing an economic test.

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[104] *See* Dave Allain, "NSTAR Gas Marketing Program," presented before the Northeast Gas Association, August 23, 2011, at http://www.northeastgas.org/pdf/d_allain_nstar.pdf.

The objective of a line-extension policy should *not* be to maximize the number of new customers. Such an objective would motivate utilities to offer excessive subsidies to new customers, which likely would conflict with economic-efficiency and equity goals. For example, existing customers would see higher rates not reflective of the benefits they receive from new customers. Utilities would tend to favor rolling the costs of line extensions into the rates of all customers. Utilities probably would also prefer that existing customers pay for marketing and outreach programs. Overall, a policy to maximize new customers would tilt rates in their favor at the expense of existing customers. One motivating factor is gas utilities wanting to compete more successfully with other fuels.

3. Affordable economical line extensions to prospective customers

A potential conflict exists between economical fuel switching from a lifecycle perspective and unaffordable up-front cost for prospective customers. As some utilities currently do, others may want to consider spreading out in time the cost obligations of a new customer. For example, instead of paying $3,000 to a utility up front, the utility could impose a surcharge of $600 annually for five years on a new customer.[105] In many jurisdictions, this surcharge would be more than offset by the customer's actual energy savings (e.g., the customer was paying $3,600 annually to his oil dealer, whereas now his annual gas bill is $2,000).

4. Fair to all stakeholders

"Fairness" is subjective, but limiting bounds can delineate between what is fair and what is unfair. For example, most people probably would agree that a utility should recover all of its prudent costs in serving new customers. Another condition is that existing customers should bear none of the incremental costs when they receive no benefits from the addition of new customers. A rolled-in pricing scheme, for example, would be inappropriate if all the benefits from fuel switching accrue to new customers or the utility itself. Fairness might also entail new customers not paying more to the utility than the additional (i.e., incremental) costs they impose on the utility.

5. Compatibility with other governmental objectives

If a state, for example, is promoting economic development and a cleaner environment, fuel switching to natural gas may be consistent with those goals. As a state entity, the utility commission may want to advance those goals within limits. Public utility statutes and commission rules would delineate those limits. The statutes, for example, may prohibit any subsidization and consideration of public benefits by the commission. Commission rules might specify new-customer financial obligations and protections for existing customers. A hybrid funding mechanism can combine taxpayer and ratepayer funding of fuel switching projected to produce non-minimal public benefits.

[105] The utility may add an interest charge.

The appropriate form of market intervention depends on whether energy customers switch to natural gas below the optimal level because of public benefits or barriers to energy consumer action. The first reason could justify more taxpayer subsidies; the second reason could call for dissemination of better information on the benefits of fuel switching and the lowering of transaction costs.

6. Optimal line-extension investments

Optimality means that the benefit of a new investment is equal to its marginal or incremental cost. Overinvestment occurs when the utility extends its lines beyond what is economically tenable. A utility, for example, may want to extend construction of new lines to inflate its rate base. Underinvestment is also conceivable, especially when the utility views building new lines as too risky relative to the returns. A simple economic rule says that a line extension is economically justifiable when it can pay for itself. For example, if a new line costs $1 million, the benefits to new customers should at least equal this amount. New customers should then be willing to pay at least $1 million to have gas service. If they are not, then from a strict economics perspective, the utility should not build the new line.

One concern is that the utility may lack the incentive to build new lines even when new customers are willing to fund them. The utility may consider the likelihood of adequate cost recovery too low or judge that it could earn a higher return from allocating its limited capital funds to other investments.

B. Dealing with conflicting regulatory objectives

As in other matters, regulators try to make the best decision in a world of uncertainty and conflicting objectives. In the end, regulators have to act based on value judgments in the face of imperfect information. In the matter of line extensions, the regulator might want to advance certain objectives that impede others. One good example is encouraging fuel switching by lowering the cost to prospective customers. Assume that the actual cost of extending a line to a customer is $5,000. Evidence shows that charging this amount would discourage many prospective energy consumers from switching. The regulator desires to lower the cost to these customers to, say, $3,000. More fuel switching would occur, but someone has to bear the $2,000 shortfall. It could be the utility shareholders or existing customers. One could argue that both options are unfair to either group. If evidence shows large public benefits from fuel switching, the regulator might want to shift a portion of the incremental cost to existing customers. The regulator could argue that because existing customers benefit from cleaner air or bolstering of the local economy, they should bear a share of the costs for service expansion.

A counterexample is prohibiting any funding of line extensions by existing customers. One way to achieve this is to charge new customers the full incremental cost. Regulators might decide that both existing customers and new customers would benefit from any economies of scope. Thus, they might even find it appropriate to charge new customers above incremental cost to allocate a portion of the benefits from economies of scope to existing customers (*see* Part III.G.2.b).

C. Service expansion to remote areas: a special challenge

State utility commissions, along with other governmental entities, might face a situation in which gas service to sparsely populated areas would have large public benefits but not be economically feasible for a utility. Access to natural gas might bolster local economic development and save residents large sums of money. Because of the low number of connections, especially during the initial years, however, it could be several years before the utility would collect adequate revenues to pay for the new lines. The utility would have little motivation to build the new lines. If the utility required new customers to compensate them for revenue deficiencies, the cost to customers might be prohibitive. Yet, in the end, the new pipes would benefit the local economy and pay for themselves as the number of new customers increases.

This scenario might call for governmental intervention. One option is for municipalities and other local governments to provide financial assistance. They can compensate for the revenue shortfalls either by reimbursing the utility or by providing direct assistance to new customers, say, for the first five years of gas service. Another option is for the state government to provide financial support. Expanding gas service could be a part of the state's energy strategy. States often provide financial support for investments that benefit the state but are not profitable for the private sector. Gas-line extensions to remote areas would seem to fall in this category. The rationale for state assistance is the inability of markets to achieve a socially desirable action because of its unprofitability.

V. Recommendations for State Utility Commissions

This paper recommends that commissions review the line-extension practices of gas utilities. Many of them may not match the current market environment. Natural gas prices have moved substantially below oil and propane prices and projections call for this relationship to continue for at least the next several years.[106] For many jurisdictions, both the private and public benefits from line extensions are likely much greater than projected at the time when commissions first approved extension rules for gas utilities. Commissions may find existing rules incompatible with current regulatory objectives and conditions in the natural gas sector. New York is one example where the Public Service Commission has recently initiated a new proceeding on examining policies relating to the expansion of natural gas service. Other state utility commissions may want to follow suit. Appendix B includes several questions that commissions can ask in their review of current line-extension practices.

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[106] At the time of this writing, propane prices were lower than fuel oil prices by around 16 percent, adjusting for consumers needing to purchase 1.37 times more gallons of propane than fuel oil to receive the same amount of heat. *See* http://www.eia.gov/petroleum/heatingoilpropane and Heating Oil vs. Propane | Irving Energy.

The basic elements of a good line-extension policy should balance the criteria of fairness, reasonableness, economic efficiency, and predictability. Over the years, state utility commissions have struggled with attaining an appropriate balance. Fairness pertains to equitable treatment of new customers, existing customers, and utility shareholders. Utilities should not overcharge new customers for line extensions. They also should not burden existing customers by charging them higher rates that are not commensurate with increased benefits from system economies. Utilities should also have a reasonable opportunity to recover their incremental costs from extending lines. "Reasonableness" relates to rates not being excessive for any customer, whether new or existing. "Economically efficient" means that a line-extension policy should provide all customers with proper price signals. Fuel switching should be cost-effective in reducing energy costs to new consumers.

Commissions should consider encouraging gas utilities to foster fuel switching through marketing, market facilitation, and financial assistance. Utilities, for example, can charge prospective customers a fee for facilitating conversion and arranging for loans. The rationale for such actions is that energy consumers are fuel switching below the socially optimal level. On the other hand, commissions need to recognize circumstances in which fuel switching is occurring at an optimal level, because in these circumstances any assistance funded by general ratepayers would be untenable.

Commissions and other governmental agencies should realize that line extensions may produce public benefits, justifying subsidies and other inducements to encourage fuel switching. Just as several commissions advocate subsidies for energy efficiency, they could require financial assistance to prospective customers who want to switch to natural gas. In fact, commissions may find that gas utilities' expending a fixed amount of dollars on fuel switching yields a higher societal return than from spending the same dollars on energy efficiency.

One idea for consideration is the development of a collaborative arrangement in which the different stakeholders would work together to expand gas lines into towns and rural areas that currently do not have gas service. They can assemble a package that calls for municipal, county, or even state financial assistance and present it before the state utility commission for review. Recent legislation in Nebraska facilitates such collaboration among parties.

A good extension policy should feature certain objectives. One is to prevent substantial or unwarranted burden on existing customers. A second objective is to create a level playing field among the different energy sources. A third objective is to allow new customers the flexibility to compensate their utility over a multi-year period for "excess" costs that existing customers or utility shareholders should not have to shoulder. Especially for line extensions in remote areas or new franchise areas that require substantial cost, a large one-time charge to prospective customers may dissuade them from fuel switching, even when it would benefit them in the end.

Policymakers might want to consider governmental financial support for line extensions that promote economic development and other public benefits. The socialization of benefits might warrant burdening a wide group of stakeholders, including taxpayers, with responsibility for funding the line extensions. Evidence of public benefits, as of now, is more theoretical in nature, as proponents of direct governmental involvement have so far provided scant empirical support to justify taxpayer funding of line extensions.

Table 1: Line Extension Options to Advance Regulatory Objectives

Regulatory Objective	Option
Good utility incentive	▪ Opportunity for utility profit ▪ Utility fully recovering prudent costs ▪ Regulatory scrutiny of costs ▪ Moderate regulatory lag
Good energy-consumer incentive to fuel switch	▪ Proper price signals ▪ Adequate information ▪ Minimal transaction cost ▪ Reasonable up-front cost
Affordable, economical line extensions to prospective customers	▪ Spreading out over time new-customer share of line extension costs
Fair to all stakeholders	▪ Utility fully recovering prudent costs ▪ Protection of existing customers from cost shifting not commensurate with benefits ▪ Level playing field for all energy sources ▪ Avoidance of excessive costs to new customers
Compatibility with other governmental objectives (e.g., economic development, clean air)	▪ Subsidies to new customers with evidence of non-minimal public benefits ▪ Combined public and ratepayer funding with demonstration of non-minimal public benefits
Optimal line-extension investments	▪ Balancing of utility profit and risk ▪ Private benefits commensurate with incremental cost

Appendix A: Gas-Line-Extension Activities in Nine States

State	Activity
Connecticut	▪ Aggressive fuel-switching plan in the state's draft energy strategy ▪ Proposed build-out plan by Northeast Utilities
Delaware	▪ Chesapeake Utility's hybrid pricing proposal before the Public Service Commission; the utility also proposed other services to facilitate fuel switching ▪ Gas-service expansion as part of a recommended state energy strategy
Maine	▪ Intense competition among gas companies to serve new areas ▪ High demand for gas in remote and other unserved areas ▪ Legislation authorizing issuance of general fund bonds for gas expansions
Minnesota	▪ Back in the early 1990s, the Public Utilities Commission's investigation of the unique problems in funding new extension lines in remote areas
Nebraska	▪ Establishment of a process to allow communities and gas utilities to advocate before the Public Service Commission for gas-infrastructure development
New York	▪ Public Service Commission-initiated technical conference on policies for expansion of natural gas service ▪ Recommendation for fuel switching to natural gas in the Governor's Energy Highway "Blueprint"
North Carolina	▪ Natural gas bonds for uneconomic line extensions ▪ Expansion funds for uneconomic line extensions
Vermont	▪ Ratepayer funding of planning and development activities for future service expansion
Virginia	▪ Special rider for cost recovery of line extensions that contribute to economic development

Appendix B: Questions State Utility Commissions Can Ask About Gas-Line Extensions

1. What are the benefits and costs of line extensions from the perspectives of (a) the utility, (b) existing customers, (c) new customers, and (d) society at large (e.g., local economy, accounting for environmental benefits)? If they differ, what implication does this have for policy?

2. When should a utility extend its lines? What are the necessary conditions? What is efficient and economical service expansion?

    - When prospective customers indicate their commitments to immediate demand?

    - Before or ahead of known (i.e., firm, committed) demand but in potentially high-growth areas?

    - If the latter, how should the utility recover any current or future revenue deficiencies?

3. What is the proper balance of risk and reward for the utility and its customers?

4. Should regulators distinguish between main lines in underdeveloped and undeveloped (e.g., rural locations without previous gas service) areas? If so, what are the implications for policy?

5. Who should pay for lines?

    - How much should new customers pay?

    - Existing customers?

    - Utility shareholders, government taxpayers?

    - What is a fair sharing of the costs?

6. How can a commission ensure a utility that it will recover all of its prudent costs for investments in line extensions?

7. Can subsidization of new customers ever be justified?

    - What do we mean by subsidization in this context?

- Is this situation similar to the federal government subsidizing rural electric co-ops to expand electric service to areas that otherwise would not be served because of the unprofitability to investor-owned utilities?

8. How should the utility recover their costs from new customers?

   - Through an existing ratemaking mechanism?

   - Through some other mechanism (e.g., special surcharge)?

9. Should the utility recover any incremental costs from existing customers?

   - Should existing customers be always held harmless when a utility extends service to new customers?

   - If not, under what conditions?

10. Over what period should a utility recover the costs for line extensions that pass an economic test?

11. Should utilities offer "no cost" extension lines to new customers? If so, who should pay for them?

12. How should utilities structure customer contributions?

    - What is their rationale?

    - How large should they be?

    - Over what timeframe should utilities recover them (e.g., one-time up-front, amortized over five years)?

    - Should they include refunds? If so, what are the criteria for refunds?

    - How can utilities design up-front customer contributions so as not to discourage fuel switching to gas that is economical?

    - Could customer contributions place utilities at a competitive disadvantage with other fuels?

    - Under what conditions, if any, should regulators include facilities paid for by customer contributions in rate base?

13. Should regulators approve line-extension projects that may not be economically feasible using traditional criteria, like NPV and IRR?

14. What incentives and disincentives does a utility have to invest in new lines?

- What explains any distorted incentives?
- What can regulators do to eliminate them?

15. What are the line-extension policies of different gas utilities in your state?
    - Do utilities have similar policies, or do they differ?
    - What are the positive and negative features of each?

FortisBC Energy Utilities
Review of System Extension Policies

March 2013

Prepared by:

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March 15, 2013

Mr. Brent Graham
Manager, Energy Product & Services
FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8

SUBJECT: Mains Extension Policy Review

Dear Mr. Graham:

Please find attached the Review of FortisBC Energy Utilities' System Extension Policies report prepared by EES Consulting. The conclusions and recommendations contained within this report are based upon industry practice and generally accepted rate setting principles.

This study has been developed independently by EES Consulting, with information provided by FEU staff, as needed. The findings, conclusions and recommendations of this report provide the basis for the development of an alternative approach for determining the system extension allowances for new FEU customers.

Thank you for the opportunity to assist FEU in this rate setting process. Please contact me directly if there are any questions about the subject analyses.

Very truly yours,

Gary S. Saleba

Gary S. Saleba
President

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Contents

Executive Summary

This report is provided to the FortisBC Energy Utilities (FEU) to address whether its current System Extension polices are consistent with the practices of other gas utilities and to determine whether any changes should be made to the policies. It is intended to provide background information for future engagement with the Commission and FEU stakeholders regarding a review of its system extension policies.

The FEU currently use a cost-benefit analysis to determine the amount of service line and main extension allowance available for each new connection. The service extension is covered by the Service Line Cost Allowance (SLCA) and is applied to customers where the proposed service line can be attached to an existing distribution main. For customers that require an extension of distribution mains, the necessary calculations to determine the allowance are completed within the Main Extension (MX) test, which includes the cost of the complete requirement for a meter, service line and any extensions of distribution mains required to serve the customer.

The SLCA is a standard allowance of $1535 per customer to cover the cost of the service line. It was calculated using the MX test along with standardized assumptions and is therefore consistent with the main extension calculations.

The MX test, used when a main extension is required, includes a 20-year cost-benefit analysis showing both the revenues and the costs associated with each new connection project. Revenues are based on expected consumption given the appliances that are planned for installation. Ongoing expenses for O&M, property taxes and income taxes are deducted from the revenue. Costs include the cost of the meter, service, plus a detailed planning estimate of the cost of any required extensions in distribution mains. Both the revenues and costs are discounted to present value (PV), and the P.I. ratio is calculated as the PV of revenues divided by the PV of costs. The FEU will fund individual projects that have a profitability index (P.I.) of 0.8 or better. On an overall basis, a P.I. target of 1.1 is set for the utilities.

EES Consulting conducted a survey of system extension policies for gas utilities in Canada and the Western U.S. In general, all utilities use some form of cost-benefit analysis. For the utilities in Canada, the approach was similar to the MX test performed by the FEU and calculations were performed for each connection project. There were some differences in the number of years included in the analysis, with most utilities using 30-40 years rather than the 20 years used by the FEU. Other minor differences occurred, however, it was confirmed that the FEU policy is in keeping with standard practice.

One alternative approach that was found was the use of standard extension credits for each appliance rather than FEU's method of using a cost-benefit for each main extension which attempts to quantify the consumption levels specific to the customer(s). This is similar to the standardized SLCA amount used by FEU for service extensions. This approach was found in

Oregon and California. The standard credits were based on an underlying cost-benefit analysis, however, the standardization led to a more transparent and easy to administer policy.

While the current FEU system extension policies are consistent with standard practice, it faces the following issues:

- It does not capture the benefits of future projects that are less costly due to the current main extension.
- It does not capture the benefit of fixed costs and overhead costs being spread over a greater number of customers.
- As the usage per customer declines over time, the MX test leads to new customers receiving a smaller main extension allowance than what was provided to customers in the past
- The upward pressure on rates resulting from reduced consumption has not been accounted for in the MX test.
- The annual reporting of actual revenues and costs highlights the impacts of reduced consumption, but is applied only to new customers. It does not account for the fact that those same reductions impact existing customers.
- There is a lack of transparency as new customers are not able to translate adding multiple gas appliances to a direct reduction in installation costs without the assistance of the FEU to perform complex MX test calculations.
- The use of a 20-year period is inconsistent with other utilities and is shorter than the useful life of the facilities in question and the corresponding depreciation period used for accounting and regulatory purposes.
- The use of a 27% overhead factor added to the cost of the extension may be inconsistent with the amount of overhead that is capitalized when the facilities are placed in rate base.

To resolve these issues, EES recommends that the MX test be adjusted to reflect consistency in the number of years used and the overhead factor applied. Further, the alternative where standard appliance credits are used would be beneficial for FEU customers and should be adopted for the residential class. These standard credits can be readily determined using the current MX test and policy. This approach would provide greater transparency to customers, would simplify the construction and planning process for the utility, and eliminate the need for annual reporting. Non-residential classes would continue to use the MX test approach, with the adjustments that have been discussed.

Additionally, FEU should begin to offer financing for the customer contributions required as a result of system extensions. This financing could be a 5-year loan at the weighted cost of capital for large projects, as is currently offered to FortisBC electric customers. For smaller customers, and as an option for large customers, a 24-month interest-free installment plan would be also appropriate.

Existing FEU Main Extension Policy

EES Consulting was retained by the FortisBC Energy Utilities (FEU) to review and assist the utility in assessing its current System Extension policy. This review looks at the current policy and the accompanying MX test as compared to the policies and tests used at other natural gas utilities.

Service lines are addressed in Section 10 of the General Terms and Conditions for each FEU utility while main extensions are addressed in Section 12. In general, FEU uses a cost-benefit approach for assessing the amount of credit allowed for both service extensions and main extensions; however, the service extension has been standardized into a fixed credit per residential and small commercial customer. For this report, the term system extension is used to include the policies related to both service and main extensions as a whole. The service extension is covered with the Service Line Cost Allowance (SLCA) and is applied to customers where the proposed service line can be attached to an existing distribution main. For customers that require an extension of distribution mains, the necessary calculations to determine the allowance are completed within the MX test, which includes the cost of the complete requirement for a meter, service line and any extensions of distribution mains required to serve the customer.

General Policy

The process for obtaining a new natural gas service for a customer of FEU, whether it is a single residential home, a new sub-division of homes or a commercial/industrial account, is to submit an application for service with the utility. This starts the system extension process whereby the utility reviews the location relative to existing infrastructure and determines the costs associated with attaching the new customer(s) to the existing system.

If the customer can be attached to an existing distribution main, the service extension falls under the SLCA covered in Section 10. Using the cost-benefit analysis contained in the MX test, a standardized credit for a service extension was first established in 1996 using a standard consumption level per customer. The SLCA was updated in 2007 to a standardized credit of $1535 for all FEU residential and small commercial customers. The service line and meter cost are covered by the utility up to the $1535 allowance, and the customer is liable for any amounts that exceed that level.

If the customer requires an addition to distribution mains, the main extension falls under the MX test covered in Section 12. The utility works with the customer to establish the expected gas consumption based on the appliances to be installed and the climate zone in which the customer falls. In many cases it is the home developer that requests the new service, even though they are not the eventual gas customer. For purposes of this report we will refer to the customer to include both direct customers and any developers or contractors acting on behalf of the eventual customers.

To determine the amount of allowance that FEU will provide to the customer that requires a main extension, a cost-benefit analysis is done using the MX test model. Note that the allowance resulting from the MX test is not additive to the SCLA as the service line and meter costs are included within the MX test. Both the costs of the installation and the expected usage for the customer are inputs into the MX test model. In general, if the profitability Index (P.I.) for the customer is equal to or greater than 0.8 the utility will pay for the cost of the installation. If the P.I. is below 0.8 the customer is required to make a customer contribution in the amount that will bring the P.I. to 0.8.

Because rates differ among FEI, FEVI, FEW and FEFN, the MX test differs for each utility and region. The calculations are the same in all cases; however the usage assumptions, costs and rates are customized for each utility. For purposes of this report, it is assumed that all discussions and recommendations encompass FEI, FEVI, FEW and FEFN, but will be referred to generically as FEU.

Of course this is a very general description of the policy and process. The following provides greater details associated with each component.

MX Test Cost Estimates

For each main extension project, FEU staff develops costs for each new customer connection. The estimate includes the cost of the meter as well as the service line. In the case of simple service lines, the utility uses the geo pricing methodology to standardize the cost per line. The price in each case includes a fixed component plus a variable component based on metres of service length. The pricing differs among the 9 regions that are identified. For more complex service lines the utility requires a more detailed manual estimate approach for the specific project. The geo-pricing is updated each year based on actual installations. For extensions to the distribution mains, each project is evaluated and designed by engineering staff to develop the cost of the project. Similar to service lines, FEU staff can use geo-pricing to estimate main extension costs in some cases where it is appropriate.

Some requested main extensions are for service to one customer while in many cases they would apply to a subdivision or development that would include multiple customers. Both the costs and the MX test are considered on a project-by-project basis rather than on an individual customer basis within the project.

In addition to the project-specific costs, an adder of 27% is applied to the service line and main extension costs to reflect the cost of overheads and administration. An additional 0.5% is added to account for working capital.

The estimated project cost is one of the inputs into the MX test model.

MX Test Customer Usage and Revenue

As costs are compared to revenues within the MX test, the revenues must be developed based on expected customer usage. The customers expected to connect to the project are looked at over a five-year period as they may not all connect at the same time. Usage estimates are based on standard annual gigajoules (GJ) of consumption per appliance for each residential customer while more specific estimates of usage are developed for commercial/industrial customers to reflect the size, type of business and gas applications expected for each customer.

FEU develops end-use forecasts for 17 different residential appliance types. The usage forecasts reflect the Residential End Use Study (REUS) undertaken by FEU every 4 years, and are adjusted to reflect 9 different zones. Customers requesting the extension must identify the appliances they plan on installing at the site, which is then used to develop the usage estimates for each connection. It is assumed that usage is consistent from year to year and reflects average weather conditions. The forecast is not designed to take into account the fact that different customers will use gas differently than one another, even with the same appliances.

For those customers that install both a high efficiency water heater and furnace in combination, FEU includes a 10% adder to the consumption estimate when calculating the MX test. For homes or business that are LEED certified, a 15% adder is applied. With these adders, customers are rewarded for installing energy efficient appliances.

The resulting number of customers and usage per year is input into the MX test model.

MX Test Model

The MX Test model has been developed internally by FEU staff to evaluate the P.I. of each main extension project, and the methodology and test parameters have been approved by the Commission in past decisions. As stated above, the primary inputs to the MX test model are the cost of each project and the estimated consumption per year. The methodology is the same for FEI, FEVI, FEW and FEFN; however, the rates for service differ between the utilities.

The model considers the total cost of the project in comparison to the net revenues provided over a period of 20 years. The model assumes all costs and revenues are in current year dollars and are not adjusted to reflect inflation. All revenues and costs are discounted to the present value using a 5% real discount rate. As inflation is excluded from the calculations for both costs and rates, it is appropriate to use a real discount rate as opposed to a nominal discount rate.

Gross revenues are based on consumption times the applicable rate for each customer class and are developed for years 1 through 20. Revenues include the basic charge per customer plus the delivery charge per GJ used but excludes the cost of gas and midstream charges. It is assumed that there are no real increases in delivery rates during the 20-year test period. While FEU does not currently project any real rate increases in the future, the decline in usage per customer over time that is occurring due to energy efficiency may place upward pressure on delivery rates over time. This upward pressure could be offset through growth in new customers.

The MX test is designed to capture the marginal revenues of the utility after annual cash outflows are deducted. This includes the deduction of O&M costs, property taxes, and income taxes.

Within the MX test, the present value of the revenues is divided by the present value of the project cost to calculate the P.I. value. If the P.I. value is below 0.8 for the project, a customer contribution is required and is input into the MX test such that the P.I. value increases to the 0.8 level. Projects that exceed the 0.8 P.I. level are funded by FEU without a customer contribution.

MX Test P.I. Requirements and Reporting

On an individual project basis, FEU uses a minimum 0.8 P.I. target to set the main extension allowance available to the customer. However, on an overall system basis the P.I. target is 1.1. Overall, the utility strives to proceed in a manner that is economic and does not lead to increases in rates as a result of adding new customers to the system. Because there are many projects with P.I. levels above 1.1, allowing a level below 1.1 on an individual basis is appropriate because the various projects will balance each other out and meet the system-wide target.

FEU is required to report results of the main extension projects to the Commission each year. While the MX test and customer contribution is based on an estimated cost, the reporting to the Commission is trued up to reflect the actual installed costs once the project is complete and the actual customer revenue. Because of the numerous extensions each year and the amount of information that was involved in each project, reporting to the Commission was originally set up based on a random sample of projects rather than on all of them. With technological and recordkeeping advancements, FEU now has the capability of readily tracking every project. While FEU has submitted this information to the Commission in addition to the random sample results, the Commission relies on the random sample to determine if FEU is meeting the P.I. target of 1.1.

System Extension Accounting Treatment

The costs associated with new customers are added to the rate base each year, including the full cost of the meter, service and main extension. An overhead amount is added to the cost of the service and main extension and is capitalized along with the direct cost to account for supervision, administration, etc. This capitalized overhead is then a credit in the annual revenue requirements against the various overhead items.

Customer contributions are included in the contribution in aid of construction (CIAC) account and are deducted from the distribution plant amounts to determine the rate base of the utility.

Financing and Security for New Customers

FEU does not provide financing for the customer contributions that are required from certain customers. Full payment of the customer contribution is required before FEU proceeds with the main extension project. This policy has been approved by the Commission in past decisions.

Issues with Current Policies

The theoretical construct for system extensions is that new customers pay their fair share and don't cause existing customers to pay higher delivery rates as a result of the new customers connecting to the system. The FEU approach of looking at marginal revenues in comparison to the cost of connection generally meets this construct. However, it is important to recognize the overall costs and benefits of new customers, even for those factors that are not readily quantified.

For main extensions in areas where growth is an ongoing factor, it is often the case that one main extension will benefit one or more future projects that are downstream. Because those future projects have not been identified at the time of the first extension, they are not quantified in the MX test. The end result may be that the first project has a P.I. level of 0.8 but the extension allows for subsequent projects to be shorter in length with a resulting P.I. level well above 1.1. In this sense, the lower individual threshold used by FEU is appropriate and reflects the interconnection of different projects over time.

A second benefit of new customers is the sharing of fixed costs over a larger number of customers, resulting in a lower cost per customer or per GJ. The nature of the facilities associated with the delivery costs of the gas utility is highly fixed in nature, with a large infrastructure for transmission, storage and general plant. At the current time, FEU's system has sufficient capacity in part due to the fact that usage per customer has been declining over time as a result of energy efficiency in building codes, new appliances, and customer practices. So while new customers require additional distribution facilities, they cause little or no additional cost for transmission, storage, general plant, and administration, resulting in a benefit to existing customers as fixed costs are spread over a greater customer base. It is important to note that the new customers may not actually cause unit rates to fall, but they have the impact of keeping the unit costs from rising as much as a result of reduced usage due to energy efficiency.

Another issue to consider is temporal equality. New customers should be treated on an equitable basis with past customers. As extension costs increase with inflation, they should not be compared directly to the depreciated values of the facilities in place for existing customers. For that reason it is appropriate that the amount of the main extension allowance increases over time to account for inflation. This is captured by the current policy where the allowance is based on retail rates, which increase over time due to inflation and other factors.

While the current method does adequately meet some of the desired qualities of a good main extension policy, there are other areas where it is lacking.

Because usage per customer has become more efficient over time, the usage per appliance forecast has been declining over time, reducing the accompanying revenues in the MX test. Customers that connected in previous periods would have had a higher amount of forecast usage and therefore a higher allowed credit resulting from the MX test. This is true despite the fact that those same customers are now also using less gas as a result of energy efficiency measures. This potentially leads to temporal inequalities between customers.

While FEU has reflected declining usage of its existing customers when estimating consumption levels within the MX test, it has not made a corresponding increase in real delivery rates in the future to reflect this declining consumption level. This provides an inconsistency within the MX test assumptions. The revenue calculated is reduced due to declining consumption without the effect of the offsetting increase in rates that result from declining usage, providing for a higher barrier for meeting the required P.I. target.

The reporting required by the Commission focuses solely on new customer connections and whether or not they are achieving the results projected with the MX test. If those customers do not use as much energy as projected, the allowance paid for main extensions are questioned. Customers that were connected historically are not included in the required reporting. As stated above, there may be temporal inequities between customers that connected in different periods, and the difference in the reporting required for new versus existing customers exacerbates that inequity

The complexity of the current MX test model, when compared to other simpler calculations, better reflects the inter-related aspects of consumption, revenues and costs. This not only makes it more difficult to administer but more importantly it is not transparent to the customer and results in confusion and uncertainty for those considering new connections. The customer must provide inputs regarding appliances and usage to FEU, but does not know what impact that will have on their contribution amount until FEU provides them with the MX test result. This makes it difficult for customers to make the connection between appliance selection, increased consumption and cost reduction.

Finally, it is important that the MX test be consistent with other accounting practices at the utility. This may not be the case for the length of time used for calculating revenues or the overhead adder. The 20-year period used for the MX test is not consistent with the useful life and depreciation factors used for distribution mains and services. Also, the 27% overhead factor used within the MX test may not be consistent with the amount of overhead that is capitalized for the distribution mains and services when they are installed.

Survey of Practices by Other Utilities

To determine whether the system extension policies and tests in use at FEU are still in keeping with those of other utilities, and to explore how other utilities may have dealt with some of the issues facing FEU, EES Consulting surveyed the practice of other natural gas utilities in Canada and the Western U.S.

The survey looked at the published policies for system extensions, contacted individuals knowledgeable of the policies, and in some cases reviewed Commission orders regarding system extension policies. In many cases system extension policies have been in place for many years and have not been addressed in regulatory filings. In many cases the policies are less defined and the tests less complex than that used by FEU.

Generally, the gas utilities in Canada use the basic cost-benefit approach in place at FEU but often the tests have somewhat different parameters. Many of the U.S. utilities use a cost-benefit approach that has been standardized so that a standard credit can be applied for each individual appliance.

While the survey considered all customer classes, much of the emphasis is related to residential customers as there are much larger numbers of residential connections each year and the issue of declining use per customer is more prevalent.

Utilities reviewed in the survey include:

- ATCO Gas (Alberta)
- AltaGas Utilities (Alberta)
- SaskEnergy (Saskatchewan)
- Manitoba Gas (Manitoba)
- Union Gas (Ontario)
- Gaz Metro (Quebec)
- Enbridge Gas (New Brunswick)
- Heritage Gas (Nova Scotia)
- Puget Sound Energy (Washington)
- Avista Energy (Washington)
- Northwest Natural Gas (Oregon)
- Pacific Gas & Electric (California)
- Southern California Gas (California)
- San Diego Gas & Electric (California)

After looking at the published system extension policies for these utilities, a follow-up telephone survey was conducted for those utilities that had a general cost-benefit analysis approach. In those cases the policies were lacking in detail regarding the parameters and assumptions in determining the cost-benefit analysis. This section discusses the findings of the survey according to topic area.

General Methodology

All of the utilities surveyed had some type of cost-benefit analysis used to develop their system extension policy, where revenues were compared to the cost of the extension to determine whether a customer was required to make a contribution. The Canadian and Washington state gas utilities all used a basic cost-benefit analysis similar to FEU's MX test process. There were some differences in the parameters, which are covered in greater detail below.

The three utilities in California and Northwest Natural Gas in Oregon used a cost-benefit analysis as the basis to establish standardized amounts of extension allowances per appliance for residential customers. Rather than applying specific parameters to each project, as is the case for FEU's main extension, a standard set of assumptions was used to determine the basic amounts determined for each appliance. The resulting allowance applies to both the service line and main extension. This standardized approach was considered a refinement of the cost-benefit approach rather than a separate methodology and is similar to the SLCA approach used by FEU. Benefits of this approach include transparency to customers as well as in consistency with treating all customers the same within each utility. This approach is discussed in more detail below.

While EES Consulting did not do a complete survey across the entire U.S., it did find one alternative methodology in use in Ohio. Dominion Gas in East Ohio had a main extension policy that provided the cost of the meter, service and up to 100 feet (roughly 30 metres) of main extension for each customer. Because this was not a common practice nor was it an improvement in the methodology used by Fortis BC, we did not collect additional data on this alternative. However, it is likely that this policy has been in place for many years and was originally based on a cost-benefit analysis. Generally, this policy appears to be more generous than the FEU approach in many cases. It is not consistent with FEU's approach to account for the expected use per customer and may not provide cost-effective results for those customers with an incidental amount of gas consumption.

Revenue Calculations

To determine the revenues for the cost-benefit analysis, the expected consumption per customer is the first step involved. For residential customers, the utilities generally use some form of usage forecast that reflects appliance installation and/or the specific region. For residential gas use, utilities generally use standard numbers per appliance for their particular region as the basis for the usage per customer for each particular case. These estimates are typically based on the average actual use of similar customers. Manitoba Gas differs in that they use a standard amount of 100 MCf per residential customer per month rather than a customized number based on which appliances are to be installed. For commercial/industrial customers, the usage forecast is customized and reflects discussions with the potential customer about the installation. FEU is generally consistent with the other utilities in this regard.

Revenues are based on the expected appliances to be installed. None of the utilities surveyed do audits to ensure that the appliances are actually installed. They generally trust that the customers are honest about their plans and will perform only occasional spot checks.

None of the utilities surveyed provide any extra incentive in the system extension calculations to account for the installation of more efficient appliances, as is the case for FEU. Any incentives for efficiency are offered through separate DSM programs. While a direct incentive for efficiency in the system extension policy is not a standard practice, this may be something that FEU wishes to continue to promote energy efficiency in new homes. Developers are generally motivated by upfront costs as they do not pay the ongoing gas bills once they have sold the homes they build. To ensure that new homes are as efficient as possible, continuing the added allowance is advisable. In addition, FEU should not penalize customers for installing energy efficient appliances when setting the amount of the main extension allowance.

Usage per customer is multiplied by current rates as the starting point for revenue calculations in the cost-benefit analyses. In all cases, utilities assume there are no real increases in the rate levels included; however, they are adjusted for inflation. FEU also assumes that rates will remain the same in real terms.

In nearly all cases, revenues for residential customers are calculated over a length of time of 30 to 40 years with revenues discounted to reflect the present value. Heritage Gas uses a 25-year period. Manitoba Gas and SaskEnergy both use 30 years, while AltaGas and Puget Sound Energy use 32 years. Union Gas and Enbridge use a 40-year period. This compares to the FEU calculations that use a 20-year period, making FEU out of sync with the other utilities. In several cases a period of 20 years or less is used for commercial/industrial customers to reflect contract length or greater business risk. This is consistent with the FEU practice for large commercial and industrial customers. As with FEU, the revenues are based on net revenues rather than gross revenues, with annual costs for O&M and taxes deducted. The net revenue is then the amount available to cover the carrying costs of the capital for fixed infrastructure associated with the new customer(s).

The exceptions to this approach are ATCO where a 3 year period is used and Avista where one-third of gross revenues are used. In these two cases, a much smaller level of costs, if any, are deducted from the annual revenues. This approach reflects more of an abbreviated method to determine the allowed main extension credit rather than calculating a full cost-benefit analysis. In fact, Avista does a 40-year full NPV analysis on its larger connections but uses the one-year approach as a simpler but comparable method for the majority of cases. It is also important to note that the Avista rate includes the cost of gas. Because these methods are less complete than what is currently done by FEU, it is not seen as an improvement over the current methodology.

Finally, the utilities all use the weighted cost of capital for discounting the forecast revenues when developing the present value. This is appropriate when inflation is applied to both the revenues and the annual costs. In the case of FEU the calculations are all assumed to be in real terms, excluding inflationary adjustments. The discount rate of 5% is then used to reflect a real rather than a nominal discount rate. This level approximates the difference between the utility's weighted cost of capital and the rate of inflation.

Cost Calculations

In most cases site-specific costs for the connection are provided by engineers or contractors for each utility. For residential customers it is common to also use some standardized costs per unit as is the case with FEU.

All of the utilities surveyed incorporate overhead costs into cost calculations. These overheads include A&G, management and engineering. While FEU uses an overhead adder of 27%, the range for the utilities surveyed run from 9% up to an estimated 50-100%. Note that these will vary considerably based on the accounting practices of each utility and what is included in various accounts. Some utilities may include engineering and management costs in the prices for extensions while others may only look at material and direct installation costs.

For consistency purposes, we believe it is appropriate for the amount of overheads added to the costs used in the MX test to be comparable to the overheads capitalized as part of the amount placed in rate base. FEU should determine if the current 27% amount is in line with the capitalized overhead and make any necessary adjustments.

P.I. Targets and Reporting

The FEU's use of a 0.8 target for the P.I. on an individual basis, along with a 1.1 overall target, is consistent with the practices of the other utilities surveyed. While there are differences among the utilities, FEU is well within the range of options used. Union Gas and Enbridge Gas New Brunswick both use the same targets as FEU. Puget Sound Energy uses a lower 0.75 target while Heritage Gas and Manitoba Gas use a 1.0 target. The other utilities either don't have a set target or look at things in a different manner.

Because of the advantages that main extensions bring relative to future extensions that may feed off of them, because of the uncertainty in forecast revenues, and because there are many instances where the MX test yields a P.I. above the 1.1 level, we believe the current FEU parameters for the P.I. targets are appropriate.

While FEU is required to file annual reporting of actual main extensions, including both the actual costs and revenues, this is not a typical practice for other gas utilities. Only Gaz Metro is required to provide annual reporting on actual extensions, along with an explanation of any differences that occur. Puget Sound Energy files an annual update on actual extensions as a courtesy but it is not required to do so. Many of the other utilities need to file information with their periodic revenue requirements filing showing the projected costs and benefits of distribution expansion projects, as they do with any other capital project. This is also the case for FEU. In some cases specific projects are questioned on occasion and looked at more closely to determine prudency. In the case of ATCO Gas any reporting requirements are being eliminated as part of the recently approved Performance Based Ratemaking (PBR).

Standardized Credit per Appliance

As previously discussed, utilities in Oregon and California have standardized the residential system extension allowance on a per appliance basis. The standardized values are based on a typical cost-benefit analysis, however, and in that sense are consistent with the FEU practice. The standardized rates for this year are shown in the following table.

	Water Heating	Space Heating	Oven/Range	Dryer Stub
PG&E	$529	$649	$57	$22
So Cal Gas	$441	$503	$77	$107
SDG&E	$554	$479	$99	$140
Northwest Natural**	$2100	$2875	$850	$850

** Not additive

For the California utilities, the approach is based on a combined Order from the Public Utilities Commission of the State of California (CPUC) and is consistent among the three utilities. While the methodology is the same, each utility uses their own assumptions about usage, rates and demographics. Usage per appliance assumptions are based on the Residential Appliance Saturation Study (RASS) conducted by the California Energy Commission (CEC). The RASS is an end use survey similar to what is done by FEU and reflects the average usage resulting from a sample of all existing customers of the utility.

The cost-benefit analysis is based on a formula where the Allowance equals Net Revenues divided by the Cost-of-Service Factor. Rather than a full blown year-by-year analysis, the Cost-of-Service factor reflects the annualized Cost of Ownership. The result is very similar to the MX test approach used by FEU, but uses a simplistic formula to represent the same theoretical concept. Because this calculation is less complete than FEU's current MX test calculations, we do not believe it should be considered in place of the current method.

The California methodology was last reviewed in Decision 07-07-019, which was based on applications submitted in 2005. The decision made some slight modifications from past practice to ensure that gas usage per appliance was based on usage within each utility's service area rather than a state-wide average and that the COS factor reflects a 60 year period with replacement costs included during that time. The Decision also confirmed the policy that the utilities offer uniform line extension allowances throughout their service territories. The actual allowance values per appliance are periodically updated to reflect current rates.

Note that the allowance values per appliance are additive for the California utilities. Because the climate and demographics are quite different from that in B.C., the allowances would differ if calculated for FEU.

For Northwest Natural, rather than additive amounts per appliance, the allowances are total amounts based on the appliance with the highest usage. For example, if the customer installs space heating it is assumed they will likely have gas water heat as well and the allowance is greater than if they have water heat without space heat. The allowance is lowest for those customers without space or water heat installed.

Financing and Security

Like FEU, most of the utilities surveyed require new customers to pay for any customer contributions up front prior to construction. There are a few isolated cases where some type of financing is available. Gaz Metro allows customers to pay contributions over 24 monthly installments. Puget Sound Energy does not have a published policy regarding financing but will on occasion allow installment payments, without interest, over a short time period on a negotiated basis for large projects. Union Gas allows new customers to pay the 1.5% late fee amount as a way to defer full payment on required contributions. Both Manitoba Gas and Heritage Gas have financing available through an outside company.

Note that FortisBC offers financing of customer contributions for its electric customers. Financing is provided for contributions that exceed $2,000 and are limited to a total of $10,000 per applicant. The financing requires a 20% down payment, is available for a 1 to 5 year period, uses a rate equal to the weighted cost of capital, and is subject to approval of credit for the applicant.

For large customers, there are often additional security requirements to reflect the risk associated with the new customer. ATCO uses a contract demand level with a take or pay clause to ensure revenues are sufficient to cover the costs of the extension. This is consistent with FEU's practice for large customers. Avista secures letters of credit or insurance bonds for large customers. For smaller customers that are new to the system it is common practice to require a small security deposit outside of the system extension process.

Alternative Methods and Recommendations

Based on the utilities surveyed, FEU appears to be fairly consistent with the utilities in Canada in its use of the MX test and current P.I. targets. The current cost-benefit approach is relatively consistent throughout the utilities surveyed, with differences primarily in the underlying assumptions rather than in the methodology. While a few utilities offered a somewhat different approach to calculating the cost-benefit, none of those alternative calculations were as thorough as FEU's current method that considers a long-term present value of costs and benefits.

There are a few areas that should be adjusted in the FEU MX test to be more consistent with the other utilities and with FEU's own accounting practices, which are explained in more detail below.

The standardized credit per appliance approach used in California and Oregon offers an alternative that is still based on an underlying cost-benefit analysis and is consistent with FEU's fixed amount for the SLCA. This approach may have some clear benefits and could be adopted in a manner consistent with the current FEU policies. This alternative is further considered in greater detail below.

Continue Current Individual MX Test Approach

The FEU's current system extension policies and MX test are for the most part consistent with other utilities in Canada. The approach has been in place for some time and is currently working adequately. There are, however, some issues that it does not address well. Continuing with the current policy as it is would require no changes to the work the utility does now and would not require additional review or regulatory process for the Commission. The SLCA for service extensions and MX test for main extensions meet the theoretical standard of having new customers cover any costs of their connection that are not already covered by the existing rate levels.

There are several areas where the current policy and calculations are lacking. This includes:

1. The inconsistency between the MX test period of 20 years and the longer useful life of the facilities
2. The potential inconsistency between the 27% overhead adder and the adder that is actual capitalized with the distribution rate base additions
3. The reduction in use per appliance that has been occurring, leading to inequities between past and current customer allowances
4. The uncertainty associated with assumed consumption for each customer
5. The administrative burden of completing a MX test for each main extension
6. The administrative burden of tracking and reporting actual results for each customer

7. The lack of transparency for the customer
8. The lack of financing available to customers for their customer contribution

The current approach could be continued and meet the overall theoretical construct provided that a few adjustments are made to resolve some of the inconsistencies. However, there are some issues that would remain with the current approach even after adjustments.

Adopt Standard Credit per Appliance

The standardized credit per appliance approach that is in place in Oregon and California provides a greater level of transparency to the customer and would provide a simplification of the process that now requires individual assumptions and calculations for each project.

While the credit per appliance method is a new method it combines several of the approaches already in place at FEU. It is similar to the SLCA in that it is based on a fixed amount that was developed from a cost-benefit analysis and does not require a separate calculation for each service extension. However, it differs from the SLCA in that it would be based on individual appliances rather than a common usage assumption for all customers across all utilities. Compared to the main extension policy, the credit per appliance would be similar in terms of the underlying assumptions and use of the MX test to develop the credits, and the assumptions would differ by utility as is presently the case. It would differ in that the assumptions would be averaged within each utility rather than differing by sub-region, and it would not require a separate calculation for each extension.

This standard credit approach is still based on a cost-benefit analysis and would therefore still meet the current theoretical construct and be consistent with the overall approach used by most utilities surveyed. If FEU were to adopt this standard credit per appliance approach it is recommended that it base the results on the current MX test and the underlying assumptions. It should also apply to both service extensions and main extensions rather than having a separate SLCA and main extension calculation. To arrive at standard credit per appliance amounts, we would suggest the following steps:

1. Start with the existing MX test for each of the utilities.
2. The length of time used should be adjusted beyond 20 years to reflect the useful life of the distribution mains, services and meters.
3. The overhead adder should be adjusted to reflect the amounts actually used when capitalizing overhead costs to the distribution mains account.
4. For each utility a standard use per appliance should be developed. This amount may differ between the utilities but would be consistent for all customers within each utility. The amount would reflect the average use of appliances currently in place rather than the use for newly installed efficient appliances. These usage levels would allow future customers to receive an allowance comparable to what was provided to customers in

the past. In addition, it would not penalize new customers for installing more efficient appliances.

5. A base level for the credit would be developed by assuming 1 GJ or less of usage for 1 customer. The amount of costs that could be supported by this level of usage and still meet the 0.8 target P.I. level would be established as the base amount. Because of the basic charge built into the rate, some revenues exist even when a minimal use of gas is assumed. This base amount would be applied for all new customers as the starting point for the credit. Additional amounts per appliance would be added to the base amount.
6. For each optional appliance, the usage level would be input in the MX test for one customer. The amount of costs that could be covered by this usage would be determined. Only the incremental amount beyond the base amount established in step 5 would be attributable to the appliance.
7. A schedule of allowances for the base amount and for each appliance would be determined for each of the utilities.
8. The current 10% adder for installing a combined high efficiency furnace and water heater and 15% adder for LEED certification would be quantified into a fixed dollar amount and be added to the standard credit if applicable. The amounts of these credits should also be reviewed to determine the appropriate levels required to achieve the desired energy efficiency.
9. Customers would receive an allowance up to the maximum amount for all the appliances to be installed for all customers to be connected within each project. In no case would the amount paid exceed the actual costs of the project installation for service and main extensions.

These steps would result in a standard list of credit amounts per appliance that would be consistent with what is offered to customers today. While the approach is based on what is offered in California and Oregon, it would be customized to reflect the current FEU policy. One difference is that it would apply to more appliances than just those offered in California because additional appliances are already accounted for in the current MX test. A second difference would be in offering a base amount to which appliance credits would be added. This is consistent with how revenues are currently calculated in the MX test with basic charges contributing to the overall revenues. This differs from the simplified California cost-benefit calculation where revenue calculations are tied to average revenue per unit rather than the actual tariff amounts.

While the standard credit approach is well suited for the residential class, non-residential classes would need to continue with individualized MX test calculations for each customer. There may be the potential to provide some standardization for businesses that are similar to one another; however, it is likely to be more expeditious to continue with the current individualization.

By using the existing MX test, which has been approved by the Commission, to develop the resulting standard credits, less oversight would be required than with a completely new approach. At the same time, the assumptions used to develop the standard credits could be reviewed and tested on a periodic basis without the need to examine the entire calculation each year. Amounts could be adjusted on a percentage basis to reflect any changes in the underlying delivery rates.

Other Issues

Two others issues to be addressed are the annual reporting requirements for FEU and the ability to offer financing for capital contributions.

The annual reporting requirements for actual costs and revenues for main extensions are inconsistent with standard practice in the industry, as most utilities are not required to submit after the fact reporting. While it is appropriate to determine whether or not the MX test results are valid, there are some inherent issues associated with the reporting. Previously we raised the issue of temporal inequities as usage is declining over time. While the annual reporting may detect differences in actual usage levels compared to the assumptions made in the MX test, it is not required for historic connections that may also be facing declining consumption. Further, basing main extension allowances on the basis of new more efficient appliance penalizes those customers that are making appropriate energy use decisions.

If the standard credit per appliance method is adopted in the future, the need for annual reporting would be eliminated as the standardized amounts would be thoroughly reviewed and approved prior to implementation. Even without a change to a standard credit, we would recommend that the annual review be eliminated or conducted less frequently to be consistent with other utilities.

Adding an option for financing of capital contributions would be beneficial and would be consistent with what is offered to FortisBC electric customers. Adopting a policy identical to that offered by the electric utility for large contributions with a 20% down payment, up to 5 year term and a borrowing rate equal to FEU's weighted cost of capital would be appropriate. FEU would need to determine whether the $2,000 to $10,000 range would be appropriate given average customer contributions for gas extensions.

For smaller extensions, or as an option for large extensions, the addition of short-term, interest-free installment payments would also be appropriate. This option would be similar to that offered by Gaz Metro and Puget Sound Energy. Allowing equal installment payments over a 24-month period, with no interest charges, would be appropriate. Because of the construction period for main extensions and the regulatory lag between when an extension is completed and when it is placed in rate base, there is likely little or no cost to the utility for this 24-month period. The current policy is likely to generate many cases where the customer contribution is placed in rate base in one year while the capital cost is not included until the following year. With a 24-month installment plan the average payment period is one year from the application date, which would line up with the average time when the extension is added to rate base.

Financing would of course need to be subject to credit approval. Payments would also need to be paid in full prior to any transfer of ownership. With both of these financing options, customer contributions would be added to CIAC and placed in rate base as they are received.

Final Recommendation

The current MX test needs some adjustments to better align with other utilities and provide internal consistencies. We would recommend that the test period be extended and that the overhead factor be adjusted to be consistent with capitalized overhead amounts. These adjustments are necessary to provide consistency with FEU's accounting practices that have been approved by the Commission. We would also suggest that appliance usage amounts be standardized to reflect a long-term average use rather than one that is declining over time. This would provide greater equity between the amount of allowances provided to past customers and future customers. These adjustments are needed regardless of whether or not standard credits per appliance are adopted or not.

It is recommended that FEU adopt the standard credit per appliance approach for residential customers currently used in California and Oregon. This would allow for a more transparent policy for the customer, would allow for oversight of the calculations used to establish the credits that are available for all customers, and would simplify the process required for new customer connections. This approach would also eliminate the need for annual reporting of actual costs and benefits by project. As discussed above, these credits can be readily established using the currently approved MX test.

Finally, offering financing options for customer contributions is recommended. This could take the form of a 5-year loan at the weighted cost of capital for large projects, as is available for FortisBC electric customers. For small customers and as an option for large customers, a 24-month interest-free installment plan would be appropriate.

CONNECTING NEW COMMUNITIES

NOVEMBER 25, 2014

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This report and the U.S. research was developed by Concentric Energy Advisors, Inc. under contract to the Canadian Gas Association. The Canadian content was prepared and contributed by the Canadian Gas Association.

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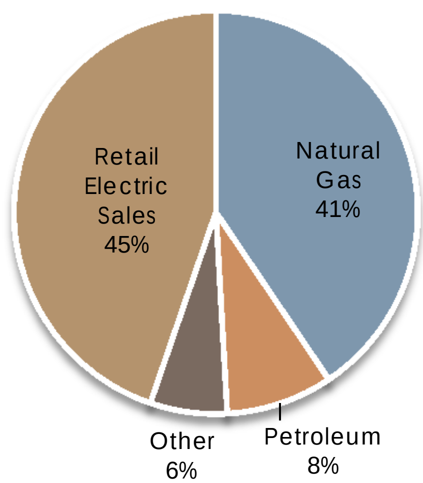
INTRODUCTION

The robust growth in North American natural gas supply is changing both the national and global energy landscape. This increase in natural gas production, due to technological advances in the discovery and extraction of shale gas, has resulted in improved competitiveness of natural gas prices in relation to alternative fuels. This environment has generated interest from communities, power producers, and large scale end-users to obtain natural gas supplies to lower their energy costs; however, incremental distribution infrastructure is often necessary to deliver natural gas supplies to new customers.

Natural gas is not considered an essential service, and therefore many regulators seek to protect existing natural gas customers from subsidizing uneconomic natural gas distribution system expansions. Traditional regulation allows utilities to expand the distribution system to connect new customers as long as the distribution revenues from the new customers offset the cost of expansion. If new customer distribution revenues are not expected to equal or exceed expansion costs, new customers have the option of paying the difference up front in order to obtain natural gas service. This up-front customer payment is often known as a contribution-in-aid-of-construction ("CIAC"). Hurdle rate models, customer contribution tests, and CIAC models are some of the terms used to describe the calculations to determine the required CIAC, if any.

Given the price and environmental advantages of natural gas over many alternate fuels, utilities, regulators, legislators, government leaders, and other stakeholders are re-examining the existing regulatory paradigm that requires new customers to pay an up-front CIAC to cover the difference between expansion costs and their expected revenue. Often the CIAC is a barrier to expansion when new customers must pay a CIAC in addition to the cost to convert their internal equipment to natural gas. Policy makers and regulators are, therefore, considering ways to reduce or eliminate the up-front CIAC. Regardless of the official documents that initiate the process, it is typically a collaborative effort between utilities, policy makers, and regulators that results in changes that allow expanding the distribution system to serve new customers and new communities.

Figure 1: U.S. Residential Energy Consumption by Fuel Type

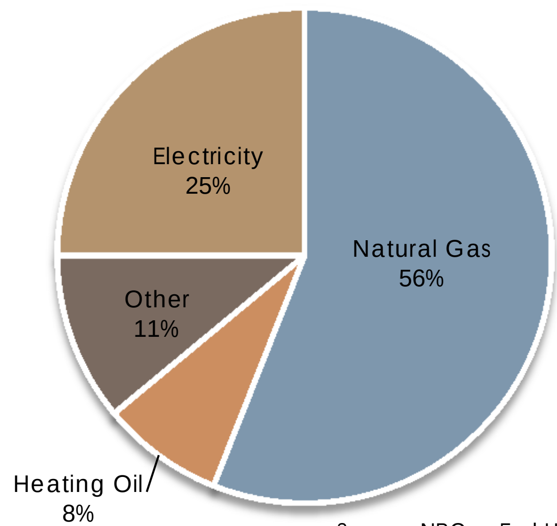


Source: EIA, State Energy Data System

As shown in Figure 1, nationwide, natural gas accounts for 41% of U.S. residential energy use, while oil represents 8%, although there is a wide variation amongst the states. Many of the states that are focused on reducing the barriers to conversion are those with higher than average oil use, as these states will tend to have greater economic benefits associated with expanding natural gas service.

As shown in Figure 2, in Canada natural gas accounts for 56% of space and water heating, while oil represents 8%.

Figure 2: Canadian Space and Water Heating Energy Consumption by Fuel Type



Source: NRCan End Use Database

Concentric was retained by the Canadian Gas Association ("CGA") to conduct a review of innovative approaches that utilities and regulators are taking across the U.S. that allow connection of pipelines to new communities. The purposes of this study are to: (i) identify the successful models being used in in the U.S., (ii) serve as a resource for CGA utilities to develop company specific strategies to engage regulators and provincial governments, (iii) aid in successful model development that will allow utilities to connect their pipeline systems to new areas within their regulated franchise areas, and (iv) communicate and educate decision makers on the opportunity that natural gas can provide communities across Canada.

The first phase of the study involved developing summaries of a sample of approaches used by ten U.S. states. These states granted utilities approval to connect new communities to their distribution systems by changing the CIAC calculation or recovery, or reducing the CIAC using alternate funding mechanisms. State summaries were categorized by the method of funding the CIAC gap. Sources used to identify the states reviewed included reports published by the American Gas Association ("AGA"), the National Regulatory Research Institute ("NRRI"), as well as Concentric's research on these matters. These summaries were intended to provide a brief introduction to various models, and to allow the CGA to determine jurisdictions for more detailed examination. These summaries are provided in Appendix A.

The second phase of the study involved conducting detailed case studies for a subset of the states included in the summaries from the first phase. Based on Concentric's research, as well as discussions with the AGA and the CGA, it was determined that the states of Connecticut, Georgia, Indiana and Mississippi would be used for case studies based on the availability on information, diversity of approach, and sources of funding. The remainder of this report contains the case studies for each state, as well as conclusions.

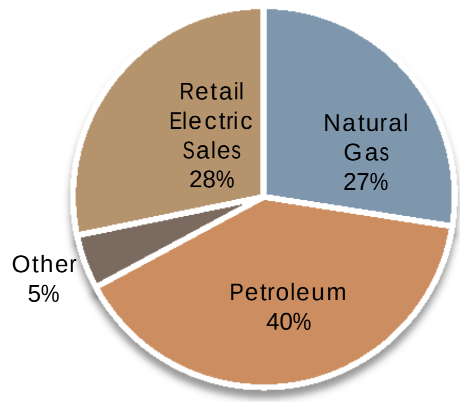
In addition, Appendix B contains a summary prepared by the CGA of programs in Canada where federal and/or provincial financial support has been provided for gas expansion projects.

CONNECTICUT

INTRODUCTION

Compared to other states, Connecticut has lower than average natural gas penetration, and significantly higher than average oil penetration for residential customers. In Connecticut, natural gas accounts for 27% of residential consumption, whereas the national average is 41%. In addition, oil accounts for 40% of residential consumption, which is the fourth highest of all states in the U.S. Given the price advantage of natural gas over oil, Connecticut consumers could benefit from moving its consumption proportions closer to the national average by increasing oil to gas conversions. Figure 3 shows residential energy consumption in Connecticut.

Figure 3: Connecticut Residential Energy Consumption by Fuel Type

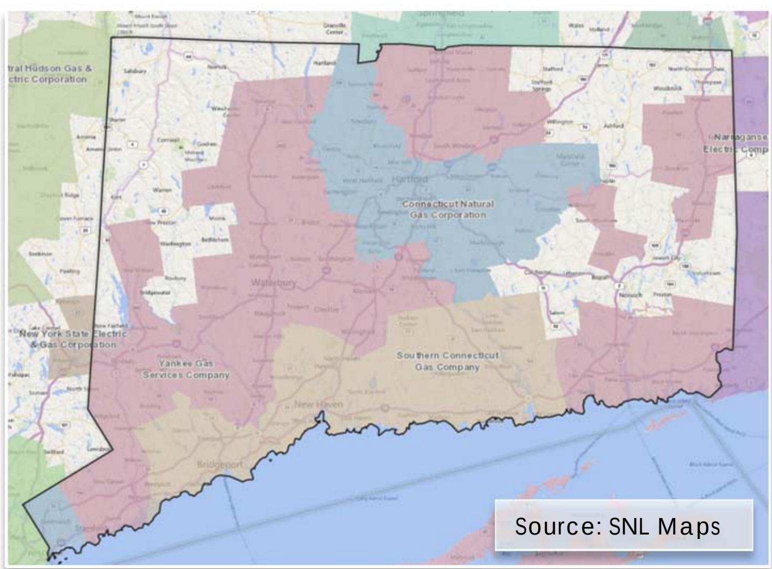


Source: EIA, State Energy Data System

Gas utilities in Connecticut are regulated by the Connecticut Public Utilities Regulation Authority (PURA), which is comprised of three gubernatorial-appointed Commissioners, each of whom serves a four-year term.

The state has three natural gas utilities: Connecticut Natural Gas (CNG), Southern Connecticut Gas (SCG), and Yankee Gas Services ("Yankee"). CNG has approximately 155,000 customers in central Connecticut, while SCG provides natural gas to 165,000 customers, and Yankee Gas has 218,000 gas customers. In addition, Connecticut has one municipal utility, which services the city of Norwich. Figure 4 illustrates the service territories covered by the gas utilities in Connecticut. Note that there are several towns in the state that have no natural gas service.

Figure 4: Connecticut Natural Gas Service Territory Map



BACKGROUND RELATED TO GAS GROWTH

In June 2011, the Connecticut legislature passed Public Act 11-80, requiring the Connecticut Department of Energy and Environmental Protection (DEEP) to prepare a Comprehensive Energy Strategy (CES) for the state every three years. DEEP issued a draft of the CES for public comment on October 5, 2012 and in February 2013, Governor Malloy issued the final version of the CES. The CES contains a number of policy proposals aimed at expanding energy choices, lowering utility bills, improving environmental conditions, creating clean energy jobs, and enhancing quality of life. The CES includes recommendations in five areas: energy efficiency; electricity supply, including renewable power; industrial energy needs; natural gas; and, transportation. With respect to natural gas, the CES calls for regulatory changes to encourage increased conversions from oil to gas. One goal of the CES is to convert 300,000 new customers over the next seven years by targeting both on-main– those within 150 feet of an existing main – and off-main customers.

The CES proposes to make gas available to as many as 300,000 additional Connecticut homes and businesses, beginning with the roughly 217,00 customers who are on gas mains now but not heating with gas. Specifically, it calls for:

- Financing options for homeowners and businesses to eliminate the upfront burden of converting furnaces, boilers, and other appliances to natural gas – with the average residential cost of about $7500 being paid back over a decade through an "on-bill repayment" system that would be collected by the gas companies but funded by banks and the capital markets, providing the average household with immediate cost savings of about $600 - 800 per year
- Alternative financing for low-income homeowners through community banks and credit unions with the state providing incentives or financing
- A time-limited tax credit for those who sign up for conversion to gas -- providing a means for defining the universe of potential new gas customers and creating greater clarity as to where gas infrastructure investments can most economically be made
- Expansion of natural gas pipeline capacity into Connecticut to meet the anticipated rise in demand for gas as a result of expanded infrastructure and gas availability
- Regulatory changes (e.g., extended payback periods, new customer rates, use of non-firm margins to offset costs) that would enable potential gas customers who are not on but are near gas mains to have their connections financed by the state's gas companies and repaid through the added revenues of their expanded customer base
- Roughly 900 miles of gas mains to be built with a particular focus on providing "anchor loads" (factories, hospitals, schools, or other facilities with significant energy consumption) with access to gas mains
- Incentives for the state's gas companies to ramp-up the required construction quickly, which DEEP estimates will translate into as many as 7000 jobs
- Utility construction projects to be linked so that the construction cost of new gas mains can be shared with those installing water or sewer pipes, fiber optic cables, or underground electric lines.

The CES cites the recent price advantage of natural gas over oil as presenting Connecticut residents and business owners with a once-in-a-generation opportunity to switch to a cheaper, cleaner fuel source. Specifically, the CES states that replacing fuel oil with natural gas offers the prospect of lower energy bills. Burning natural gas also decreases the level of harmful air pollution in comparison with fuel oil – and even more dramatically in comparison to coal. A switch to domestically available natural gas also helps customers break free from the price spikes that result from a dependence on oil, since so much of America's oil is imported from unstable regions of the world. The CES also seeks to promote an enhanced regulatory structure designed to provide fuel flexibility and diversity. It offers a path toward greater consumer fuel choice and long overdue investments in infrastructure that will make it easier for many Connecticut residents and businesses to take advantage of the opportunity to heat with lower cost and cleaner burning natural gas.

Because the CES itself is a strategy document and does not have the authority to implement change, Public Act No. 13-298, approved on July 8, 2013 by the state legislature, provided a statutory framework for natural gas expansion and other elements of the CES. Section 51 of the Act required that gas companies jointly submit a natural gas infrastructure expansion plan to provide gas service to on and off-main customers as consistent with the goals of the CES. Among other things, the gas companies were required to include (1) an outreach plan tailored to each customer segment; (2) a strategy for gas procurement; (3) a strategy for leveraging third-party investment to finance equipment replacement and main extensions for new customers; (4) a description of steps the gas companies will take to reduce the costs of conversion; and (5) an analysis demonstrating the feasibility of reaching the new customer conversion goals.

Pursuant to the Act, in July 2013 the state's three natural gas utilities filed a joint proposal with PURA, outlining a rate plan to finance the connection of 280,000 new customers by 2023 – the proposed goal of 300,000 in seven years was deemed too high. The plan targets potential customers who are off-main as well as potential customers that are within 150 feet of an existing main. CNG/SCG proposed to convert 29,500 low-use (non-heating) customers to heating and add 113,700 new on-main customers and 54,000 new off-main customers. Yankee Gas proposed to convert 10,000 low-use customers to heating, and add 41,296 new on-main customers and 31,125 off-main customers. The companies plan to achieve these targets with changes to the CIAC/Hurdle Rate model (see below), incentives, financing options, and targeted marketing campaigns. The marketing campaign requires substantial internal and external resources, and the ability to secure and deploy these additional resources received significant attention in the proceeding.

In November 2013, the PURA approved the joint infrastructure plan, with a number of requirements, including: filing capacity plans to demonstrate that utility supply/capacity portfolios can accommodate expected customer growth; filing a cost conversion calculator and presenting this material to customers; adding O&M expenses to the Hurdle Rate models; and submitting an audit that compares the estimated costs, sales, and revenues used in the Hurdle Rate analysis to the actuals. The PURA also instructed the companies to file a marketing plan tailored to meet the customer conversion goals as well as specific activities associated with conversions and the resources required to conduct those activities.

GAS GROWTH FUNDING MECHANISM

The approved joint infrastructure plan includes several modifications to the CIAC calculation (also called the hurdle rate test in Connecticut). First, all utilities are authorized to use a 25-year payback period (previously they were using either 15 or 20 years, depending on the utility). It also eliminates the requirement to perform a hurdle-rate test or collect a CIAC for most customers located less than 150 feet from an existing main (with certain specific exceptions). Utilities are now permitted to use a "portfolio view" approach to modeling projects by aggregating off-main customers in a common geographic location when calculating the CIAC. Portfolio projects may move forward with construction as long as the project has (1) enough committed customers to secure 60% of the revenue needed to make the project viable and (2) enough prospective customers along the proposed expansion route to make up the remaining 40% over a three to five year period.

In addition, new customers added after Jan. 1, 2014, will be charged "new customer rates" (i.e., system expansion premiums), which include a monthly premium above current distribution rates to offset, and often eliminate, the need to collect a CIAC. On-main customers will be charged a 10% premium, and off-main customers will be charged a 30% premium on the distribution components of standard rates. After the initial ten years of service, new customers return to standard rates, with exceptions for customers who are far from the main or have complex construction requirements.

A portion of non-firm margin (NFM) credits (i.e., revenue earned through interruptible and off-system sales) will be used to offset expansion costs rather than returned to customers. Previously, the utilities returned 100% of NFM credits to customers as a credit on their bills. The PURA's order directs at least 50% of all NFM credits to be used to offset the expansion costs of plant additions. The remaining 50%, or $15 million, whichever is less, must go towards offsetting the costs of projects deemed to have societal benefits, such as increased employment or local economic development. Thus, NFM credits are no longer returned to customers, but are rather used to offset the costs of expansion and other projects with broader benefits to society.

PURA's decision also addresses gas companies' need to recover their capital costs related to expansion outside of a rate proceeding. If the system expansion premiums and NFM revenue are insufficient to cover ongoing expansion costs, the companies would be permitted to utilize a System Expansion Reconciliation (SER) mechanism to annually true-up gas-expansion-related revenue requirements and actual revenues between rate cases. This mechanism is effective as of January 1, 2014. The SER is to be a separate, stand-alone, line item on customer bills, and is to be incorporated into general rates during the next base rate case. In order to recover costs, the gas companies must report expenditures to PURA to demonstrate that any purchases are in-service, used, and useful.

The ruling denied the gas companies' request for additional financial incentives to meet customer conversion targets and other policy objectives, but indicates PURA's willingness to revisit the issue if the companies demonstrate tangible cost savings and other efficiencies under the plan.

RESULTS TO DATE

While the CES goal included converting 300,000 customers, which was reduced to 280,000 customers in the companies' joint plan, the PURA remained concerned with the companies' ability to achieve the total number of conversions. It was recognized that low use and on-main conversions will be more achievable than off-main conversions due to their cost-effectiveness and minimal customer acquisition barriers; however, even the level of the low use/on-main conversion goals raised concerns.

The PURA also remained skeptical of the companies' ability to secure the resources required to achieve their conversion targets. The companies met with contractors, state agencies, organized labor, and trade unions to address the need for additional resources and propose doubling their construction crews by 2019. However, the PURA recognizes that the ability to secure personnel threatens the pace at which gas conversion activities can progress. Off-main customer additions were proposed to begin as early as 2014, which does not leave much time for training, recruitment, and certification in the areas of marketing, sales, construction, supervision, and safety. In addition, there may be strains on the ability to find sufficiently qualified labor. Resource procurement is further challenged by the large numbers of potential retirements within their internal workforces over the next five years. The need to supplement in-state labor with out-of-state resources undermines the full economic benefits of the program. As a result of these concerns, the companies are required to file an annual resource plan that includes plans for workforce training and compensation, plans for sequencing system expansion, contracting arrangements with selected vendors, plans to expedite permitting with the cities and towns, and cost and schedule performance.

Each company must submit monthly filings regarding the Hurdle Rate analysis/CIAC estimates for each off-main portfolio view project on which the company began construction during the previous month. The gas companies are also required to submit annual reports to PURA and the DEEP, which include information such as the number of added customers, estimated and actual expenditures, and forecasts of customer conversions. These reports must include:

- The number of customers added for the prior year by type of conversion and by customer class;
- A comparison of actual to estimated expenditures for the previous year; and
- A forecast of the new number of customers and expenditures expected for the following year.

Finally, reconciliation filings must be submitted annually. Any new rates from this reconciliation would be implemented the following year. These reports would include, but are not limited to the following:

- The annual revenue requirement forecast for the upcoming year;
- A calculation of SER and changes (if needed);
- A calculation of NFM offsets;
- A residential conversion credit calculation;
- A performance incentive calculation; and
- Details of large project expansions, including any projects that have been evaluated using a societal benefits analysis.

The first annual report for the CES program is due to the Commission on January 2, 2015. The gas companies and PURA have identified several future events that would prompt a re-evaluation of the plan as they would impact key elements. Some of these re-evaluation triggers include: (1) over a 50% decline in the difference between the price of oil and natural gas; (2) plan expenditures increasing the overall average residential bill by at least 5% in any given year or by at least 15% over the life of the plan; or (3) a variance of 20% between the number of forecasted and actual customer conversions.

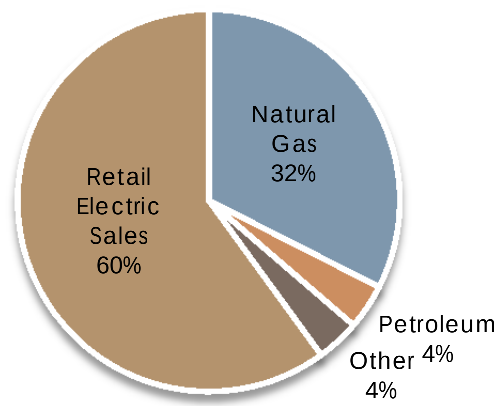
GEORGIA

INTRODUCTION

Compared to other states, Georgia has lower than average natural gas penetration, and below average oil penetration for residential customers. In Georgia, natural gas accounts for 32% of residential consumption, which is lower than the U.S. average. In addition, oil accounts for 4% of residential consumption, which is among the lowest in the United States. Figure 5 shows residential energy consumption in Georgia.

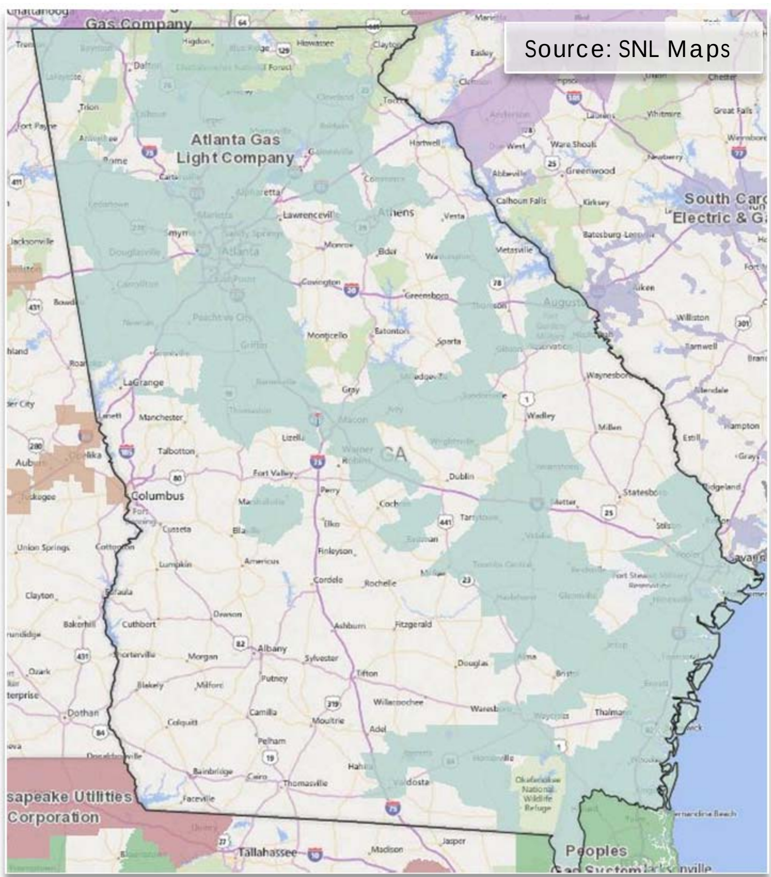
The Georgia Public Service Commission (GPUC) is comprised of four elected commissioners, each of whom is elected in a statewide election and has a six-year term. In addition, there is a Chairperson of the GPUC who is elected by the fellow commissioners and has a two-year term. The state has two natural gas utilities: Atlanta Gas Light Company (AGL) and Liberty Utilities. AGL serves approximately 500,000 customers in Georgia. Liberty Utilities has approximately 60,000 customers and operates primarily in Columbus and Gainesville. As shown in Figure 6, there are many communities unserved by existing distribution.

Figure 5: Georgia Residential Energy Consumption by Fuel Type



Source: EIA, State Energy Data System

Figure 6: Georgia Natural Gas Service Territory Map



BACKGROUND RELATED TO GAS GROWTH

Regulatory approaches to gas growth in Georgia evolved over time commencing from AGL's pipeline replacement program. AGL's Strategic Infrastructure Development and Enhancement Program (STRIDE) began in 1998 with a Pipe Replacement Program. Subsequently, in 2009, STRIDE was expanded to include an Integrated System Reinforcement Program, and in 2010 an Integrated Customer Growth Program. In combination, these programs are used to update and expand distribution systems, improve system reliability, and meet operations flexibility and growth.

To ensure the safety and reliability of AGL's system, the GPSC approved a settlement in 1998 for an accelerated cast iron and bare steel pipeline replacement program. The program ended in 2013 after the replacement of 2,700 miles of pipes. The Pipe Replacement Program paved the way for additional STRIDE programs. The Integrated System Reinforcement Program was approved in 2009 to address the increased risk of service disruption during peak-day conditions resulting from demand growth in outlying service areas. The Integrated System Reinforcement Program included: 1) the establishment of a 10-year Capacity Plan to ensure the availability of sufficient interstate pipeline capacity and storage services, and 2) the establishment of a 3-year Construction Plan to ensure the adequacy of intrastate pipeline capacity.

From the period between 2006 and 2009, population growth considerably outpaced gas growth in the Atlanta region. The Sustainable Environment Economic Development Program (SEED) was developed in 2009 to focus on economic incentives for businesses to promote natural gas adoption through discounted utility rates as well as financing incentives for new line extensions, new natural gas equipment, and equipment installations was adopted. In order to ensure the effectiveness of SEED, an additional program for pipeline expansion into areas with high business growth and economic impact was needed, which laid the foundation for the Integrated Customer Growth Program approved in 2010 to allow AGL to extend its pipeline facilities to areas without pipeline access.

The Integrated Customer Growth Program is comprised of two investment components. The first consists of support for gas line extensions to customers who are located far from AGL's facilities. Previously, customers who wanted gas service, but were not located near an existing pipeline were required to pay a CIAC, which presented a barrier to gas growth. AGL uses STRIDE funds to offset the high CIAC costs. The second investment component consists of constructing gas distribution facilities and mains in strategic areas where economic growth of industrial, commercial, or residential customers are forecasted, as well as to locations where existing industrial, commercial, or residential developments lack gas accessibility. In order to identify these "strategic corridors", a survey was conducted amongst all stakeholders as well as builders, developers, economic development authority representatives, county commissioners, chamber of commerce representatives, and natural gas marketers.

GAS GROWTH FUNDING MECHANISM

The overall rate increases associated with STRIDE faced opposition from both consumer advocacy groups as well as natural gas marketers utilizing AGL's infrastructure who argued that the program placed an economic burden on consumers in a recovering economy, and adversely affected marketers' competitiveness. Despite opposition, the GPSC approved AGLC's plan due to the long-term savings for consumers that were vital to Georgia's economic development.

Costs associated with the Integrated Customer Growth Program will be recovered by extending the STRIDE surcharge recovery period instead of increasing the surcharge on customer bills. AGLC petitioned the Commission to extend the recovery period three years – from 2022 to 2025 –which the GPSC granted since it will prevent further rate increases.

RESULTS TO DATE

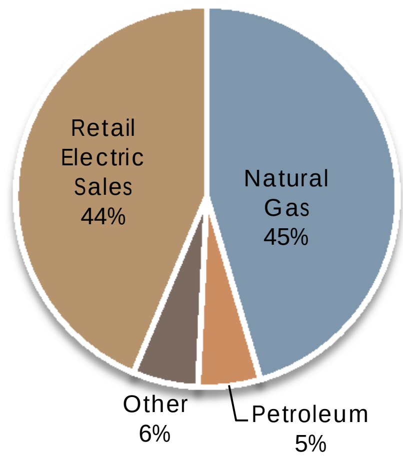
In 2009, a STRIDE surcharge was added to all customer bills to recover costs associated with Pipe Replacement Program and Integrated System Replacement Program, which will be in place through 2022.The GSPC provided clear requirements for reporting and accountability regarding the STRIDE programs, including the Integrated Customer Growth Program. Quarterly, AGL is required to submit a filing on its progress towards the Integrated Customer Growth Program plan. Annually, AGL is required to file reports that provide updates on actual costs incurred. From 2010 to 2013, AGLC invested $40 million in its Integrated Customer Growth Program. According to the latest quarterly Integrated Customer Growth Program report, a total of 310,000 feet of pipe have been installed in six strategic corridors around Atlanta.

INDIANA

INTRODUCTION

Indiana has comparatively higher than average natural gas penetration, and lower than average oil penetration for residential customers. In Indiana, natural gas accounts for 45% of residential consumption, whereas the national average is 41%. In addition, oil accounts for 5% of residential consumption, which is lower than the U.S. average of 8%. Figure 7 shows residential energy consumption in Indiana.

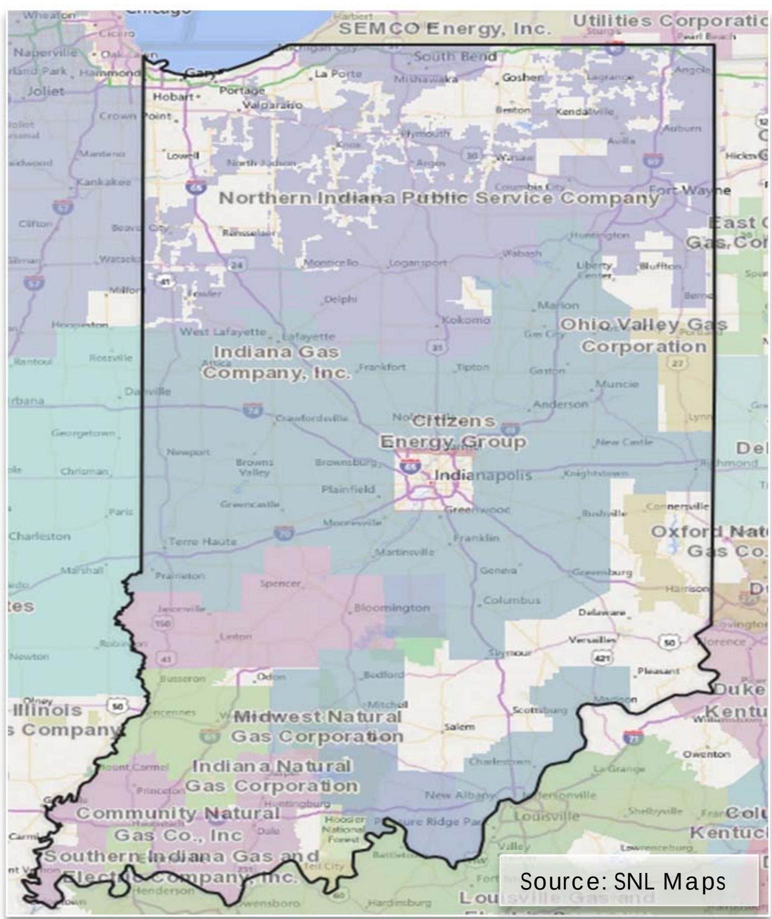
Figure 7: Indiana Residential Energy Consumption by Fuel Type



Source: EIA, State Energy Data System

The Indiana Utility Regulatory Commission (IURC) consists of four commissioners and one chairperson. Both the commissioners and the chairperson are appointed by the governor of the state and have an office term of four years. The state has two natural gas utilities: Northern Indiana Public Service Company (NIPSCO) and Vectren. NIPSCO, with 800,000 customers, primarily serves northern Indiana, while Vectren serves approximately 700,000 customers in central and southern Indiana. As shown in Figure 8, a few communities are unserved by existing distribution systems.

Figure 8: Indiana Natural Gas Service Territory Map



BACKGROUND RELATED TO GAS GROWTH

On April 30, 2013, the Indiana state legislature approved Senate Enrolled Act 560, which allows an investor-owned electric or natural gas utility to seek IURC approval of a 7-year infrastructure improvement plan, which includes components related to growth. If the plan is approved, the utility may then adjust its rates every six months to recover project costs as they are incurred. Cost recovery is subject to review by the IURC and the Indiana Office of Utility Consumer Counselor.

In the 4th quarter of 2013, both NIPSCO and Vectren filed separate 7-year natural gas system improvement plans. In both cases, intervention from the consumer advocacy group Citizen's Action Coalition of Indiana and industrial users who were concerned the improvement plans would impact rates if approved. In both cases intervener petitions were resolved with a joint order ensuring the interests of interveners would be taken into account. The IURC approved NIPSCO's filing on April 30, 2014 and Vectren's on August 27, 2014.

NIPSCO's 7-year plan allocates $713 million for transmission, distribution, and storage system improvements. Furthermore, recovery of these improvements and upgrades are accomplished through a cost tracker known as the Transmission, Distribution, and Storage System Improvement Charge (TDSIC). Over the next few years, NIPSCO plans to pursue several projects including:

- Installing 80 miles of transmission pipeline and adding automated valve ($280 million);
- Eliminating bare steel gas mains and replacing them with low pressure systems ($61 million);
- Constructing natural gas service to rural areas ($99 million);
- Retrofitting lines for in-line inspection ($46 million).

NIPSCO's rural gas extension project allows customers to request extension within a 12 month period each year. Once the 12 month period closes, NIPSCO will analyze the requests for that year and implement projects that are operationally feasible and can be readily undertaken. These projects include investments in new gas mains, stations, and services to ensure natural gas availability in rural areas. NIPSCO plans to spend a total of $99 million for rural gas extension under the 7-year plan.

Vectren filed separate 7-year plans for each of its subsidiaries: Vectren North and Vectren South. Vectren allocates $650 million to focus on: (1) System and Pressure Improvements, (2) Storage Operations, (3) Instrumentation and Communications Equipment, (4) Public Improvement Projects, (5) Service Replacements, and (6) Economic Development Projects. Vectren's Economic Development Projects include both commercial and rural areas. Vectren plans to spend a total of $27 million for commercial gas expansion and $20 million for rural gas expansion for its Vectren North's 7-year plan. Vectren South's 7-year plan will only target commercial areas and invest a total of $2 million. Vectren notes that the 7-year plans will support 1,400 jobs annually and boost government revenue by $5 million annually.

GAS GROWTH FUNDING MECHANISM

All of the programs included in the utilities' 7-year plans will be collected from all customers through one TDSIC. Details associated with NIPSCO's TDSIC are presented below. Vectren's rate recovery is similar in concept.

As per Commission approval, NIPSCO's TDSIC cannot exceed 2 percent of total retained revenues for that year. NIPSCO's TDSIC tracker works similarly to a CapEx tracker in that the Company will receive a periodic automatic adjustment of its basic rates for 80 percent of approved capital expenditures and TDSIC costs. More specifically, the TDSIC rate may be increased every six months and is allowed under the law Indiana Code 8-1-39. The remaining 20 percent of costs will be recovered as part of the Company's next rate case, which must be filed before the end of the 7-year period. NIPSCO proposes to implement Construction Work in Progress (CWIP) ratemaking treatment related to the recovery of financing costs incurred during the construction of capital projects.

NIPSCO's 7-year plan has a total of $713 million in natural gas investments through 2020, with a $55.3 million investment in 2014 and a $116.1 million investment in 2020. Average bills are projected to see a gradual average increase of approximately 1.4 percent annually through 2020, with no change in 2014 and a 1 percent annual increase in 2015. Construction is set to begin in late 2014, with the first rate increase of approximately 1.0 percent taking effect in 2015. The annual rate increase from 2016 through 2020 will vary by year, ranging from 1.5 percent to 1.9 percent. The average annual percentage increase over the 7-year term is 1.4 percent. NIPSCO plans to file its first TDSIC natural gas rate adjustment request in September 2014.

RESULTS TO DATE

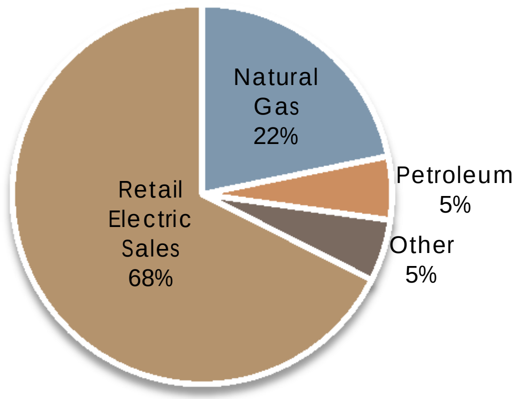
Due to the recent approval of NIPSCO's and Vectren's 7-year plan filing at the time of this report, there have not been any recorded results. To ensure accountability and transparency, the IURC imposed annual reporting requirements for the 7-year plan's progress including: 1) approved projects, estimated construction start dates, and estimated in-service dates, 2) approved cost estimates for each project, 3) revised project cost estimates, construction start dates, and actual in-service dates, and 4) explanation for any proposed revisions, including new projects or projects proposed for removal from the plan. The Office of Utility Consumer Counselor, the state agency representing ratepayer interests, as well as intervenors will collaborate with the utilities to refine the contents of the annual reports over time.

MISSISSIPPI

INTRODUCTION

Compared to other states, Mississippi has lower than average natural gas penetration, and lower than average oil penetration for residential customers. In Mississippi, natural gas accounts for 22% of residential consumption, compared to the national average of 41%. In addition, oil accounts for 5% of residential consumption, which is also below the national average. Mississippi also has the seventh highest percentage of retail electric sales in the United States. Figure 9 shows residential energy consumption in Mississippi.

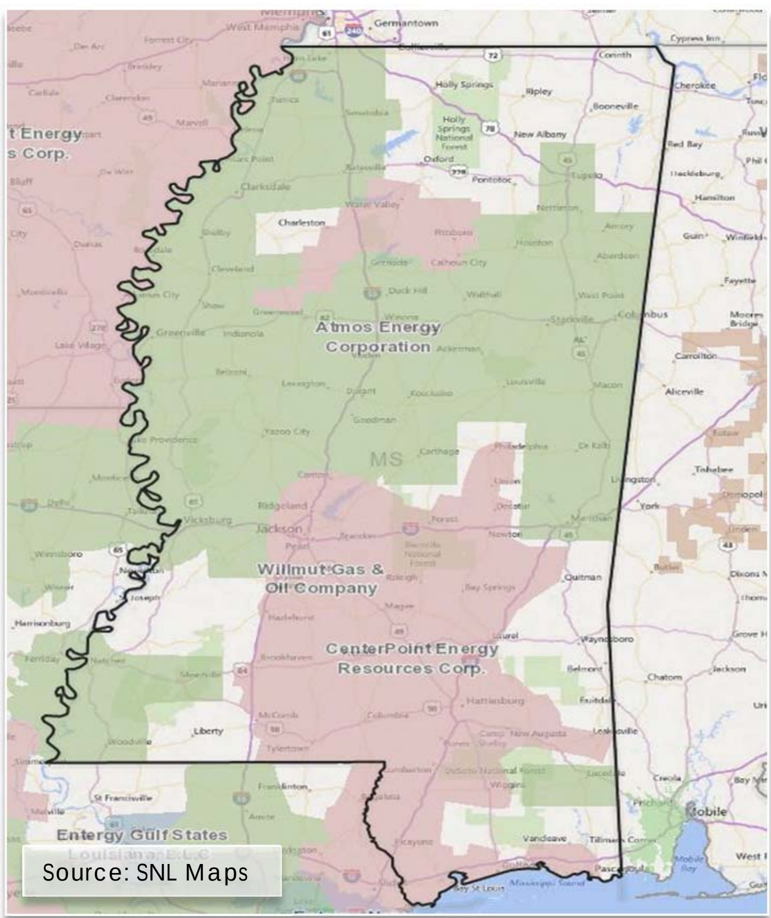
Figure 9: Mississippi Residential Energy Consumption by Fuel Type



Source: EIA, State Energy Data System

The Mississippi Public Service Commission (MPSC) is comprised of two commissioners and one chairperson. The public elects commissioners for four-year terms in a statewide vote; a new chairperson is chosen each year by the other commissioners. The state has two large natural gas utilities: Atmos Energy Corp. ("Atmos") and CenterPoint Energy Resources Corp. ("CenterPoint"). Atmos predominately operates in central Mississippi, serving 255,730 customers while CenterPoint operates mainly in southern Mississippi, serving a customer base of 123,600. Both companies also provide gas service to northern Mississippi but to a lesser extent. Northern Mississippi is primarily served by small local distribution companies or municipal utilities.

Figure 10: Mississippi Natural Gas Service Territory Map



Source: SNL Maps

Despite the cost and environmental advantages of gas over other fossil fuels, there is little demand for natural gas due to the relatively warm climate and few incentives for utilities to provide gas expansion for residential and commercial customers. As a result, most gas development and growth initiatives in Mississippi are focused on industrial users.

BACKGROUND RELATED TO GAS GROWTH

On February 5, 2013, Atmos filed a proposal with the MPSC for a Supplemental Growth Rider (SGR) that would incentivize the company to invest in extending gas service for industrial projects. The company proposed to invest up to $5 million annually with the agreement that all projects up to $5 million will not require regulatory approval. Furthermore, any projects exceeding $5 million are to be MPSC approved. In return, the company proposed to earn an additional 3% on their ROE.

The goal of this recovery mechanism is to promote economic development in the state by attracting industrial development that will generate employment opportunities. Traditionally, industrial sites are chosen based on access to highways, railways or rivers, as well as water, sewer and electric transmission facilities. Access to natural gas tends to be a secondary priority in establishing industrial site locations, and, as a result, most industrial sites often lack adequate natural gas equipment, or have none at all. The state and utilities are then faced with the burden of funding large expansions projects to those sites. One way utilities recoup these expansion costs is through the CIAC. It is not uncommon for potential businesses to seek more affordable locations if the CIAC required becomes prohibitive. The purpose of establishing a SGR, is to reduce the significant overhead cost barriers often associated with establishing gas services to an industrial site, and, therefore, to attract industrial customers, which not only creates immediate jobs at the facilities, but also aids overall economic development by increasing the demand for related services such as other energy, transportation, logistics, etc.

The MPSC approved Atmos' SGR filing on July 11, 2013 stipulating that Atmos invest up to $5 million annually to expand gas service for industrial projects ("supplemental investment projects") that would have otherwise been uneconomical. Projects below the $5 million threshold do not require Commission approval, while those above the threshold must be approved by the Commission in advance. Furthermore, the MPSC determined that a total allowed ROE of 12% would be more appropriate than the Company's proposal to increase their ROE by 3%.

Following approval of Atmos' SGR, CenterPoint filed for its own SGR. The provisions were nearly identical to those contained in Atmos' final order. CenterPoint's proposal contained one additional provision: "If no RRA [Rate Regulation Adjustment Plan]…or successor annual formula rate plan is in effect at the end of a 10-year period, then the existing rates will remain in effect until modified by subsequent Commission order." This provision acts as a guarantee of recovery in the event that CenterPoint changes the company's ROE over the next ten years. In other words, even if the ROE determination is drastically different in ten years–either unexpectedly higher or lower than today – the company's investments will still be recovered in accordance with the conditions in the final order. The MPSC approved CenterPoint's SGR filing on October 15, 2013.

GAS GROWTH FUNDING MECHANISM

The following provisions related to the funding mechanism for the Supplemental Growth Rider were included in the MPSC approval:

- Supplemental investment projects must be selected in consultation with the Mississippi Development Authority (MDA).
- Investments are authorized to earn an equity return (ROE) equal to 12 percent for a 10-year period. At the end of ten years, the investments and related expenses for the first vintage year of investments will be recovered through the Stable/Rate rider at the Company's then current Performance Based Benchmark Return. Thereafter, each year another vintage year of investments will be transferred out of the SGR and into the Stable/Rate plan for future recovery.
- The revenue requirement rate base will consist of plant, accumulated depreciation, and ADIT. Rate base will include projected costs for the next rate period plus historical costs of previous investments.
- Expenses included in the revenue requirement will include projected depreciation expenses, property taxes, interest expenses, cost of equity, income taxes and municipal franchise taxes, if applicable.
- Annual SGR reports will be filed concurrently with the annual rate filing (the "Stable/Rate filing"), including supporting documents needed to evaluate each of previous year's projects in-detail.

The SGR will be collected through a surcharge added to customers' base rate charges after application of the Stable/Rate factor. The Stable/Rate factor acts as a guarantee and ensures that Atmos earns a 12% ROE regardless of whether there is a revenue requirement identified in the annual rate filing. The revenue requirement will be distributed to each rate code pro rata based on 12 months of revenue then equally to each customer under that rate code.

The supplemental growth rider distributes funding of gas service expansion between ratepayers and the utility. Replacing CIACs with a utility investment as well as an extended recovery period shifts part of the financial burden away from the ratepayers and transfers it to the utilities. For the first ten years, the utilities bear the cost for investments establishing gas service to industrial projects.

RESULTS TO DATE

On Sept. 25, 2013 Atmos announced a multi-phase, multi-year expansion of its facilities in the Meridian area, which contains three industrial parks. In addition to constructing new facilities, Atmos will also reinforce existing facilities to allow for increased natural gas demand. Atmos expects to invest $7.5 million during Phase 1 of the project. The timing and costs of the other two phases will be determined by the timing of demand and cost of materials. The company anticipates it will take six years to complete all aspects of the project. The company initiated Phase 1 on August 17, 2014 and is in the process of obtaining right-of-way agreements related to routing pipes across municipal-owned land. So far, the company has received favorable responses from the municipal boards in granting Atmos clearance to lay pipes across municipal-owned property lines.

CONCLUSIONS

A combination of gas supply fundamentals, environmental and economic policies are paving the way for innovative mechanisms designed to expand and reinforce the existing gas infrastructure to bring access to new customers. Switching to natural gas can lower fuel costs, create economic development, improve the competiveness and lower the emissions profiles of energy intensive industries. To capture these benefits, policymakers, regulators and utilities have worked together in several states to adopt policies promoting the growth of natural gas.

In adopting these policies, regulators and utilities have been forced to address the issue of who pays for growth. When system expansions are self-funded by revenues created from new or expanded service, existing customers can be held harmless. When the cost of expansion exceeds the projected revenues from these new customers, the revenue gap must be filled from either these new customers, existing customers or alternative funding sources. Concentric's research focuses on these hybrid-funding mechanisms in the U.S., which represent a departure from traditional utility ratemaking.

Appendix A to this report contains a summary of ten states that adopted alternative funding mechanisms to promote gas system expansion. To the extent possible, we isolate the growth elements, but this is not always possible when they are combined with other programs. In the main body of the report, we dig deeper into four states that illustrate a range of solutions that are being adopted with additional detail on program provisions.

This research leads to a few fundamental conclusions:

1. Many communities remain underserved by access to natural gas infrastructure.
2. Policymakers, regulators and utilities have recognized that traditional ratemaking approaches, designed around principals of protecting existing customers from the near and mid-term rate impacts of system expansion, do not adequately consider longer-term public and private benefits of expanded access.
3. Public objectives such as lowering energy costs for consumers, promoting economic development, job growth, or meeting environmental policy goals are often linked to gas expansion policies.
4. Operational objectives are often combined with system expansion, such as system reinforcement or replacement of aging or leak-prone pipe.
5. Expansion projects are being supported and funded through a variety of mechanisms that supplement rates recovered through standard tariffs. Identified alternatives include:
    a. Recovering new customer connection costs through rates over longer periods (e.g., 25 years vs. 15 years)
    b. Elimination or reduction of any incremental customer charge (CIAC) for connection
    c. Relaxation of customer sign-up thresholds for expansion (e.g., 60% of required revenues for project viability)
    d. Temporary rate premiums for new customers until expansion costs are recovered
    e. Expansion cost offsets from interruptible and off-system sales, or purchased gas variances

   f. Special rate riders/capital trackers for approved projects
   g. Streamlined regulatory review processes and approvals
   h. Customer surcharges based on relation to alternative fuels
   i. State funding for system expansion, or grants to customers for conversion to natural gas
   j. ROE premiums applied to system expansion investment

6. Many of the identified programs are relatively new, and the results achieved are not well established, suggesting an iterative or learning approach as these programs mature.

APPENDIX A – STATE MECHANISMS TO FUND DISTRIBUTION EXPANSION

The following summaries provide a sample of approaches in the U.S. that have been used to grant utilities approval to connect new communities to their distribution system by changing the CIAC calculation or recovery, or reducing the CIAC using alternate funding mechanisms. State summaries are categorized by the method of funding the reduced CIAC. (i.e., primarily funded by existing gas customers, funded by a combination of existing and new gas customers, or primarily state funded.) Sources used to identify the states reviewed include reports published by the American Gas Association ("AGA"), the National Regulatory Research Institute ("NRRI"), as well as Concentric's research on these matters.

The summaries are grouped into categories based on the method of funding the CIAC.

I. Primarily Funded by Existing Gas Customers
   a. Indiana
   b. Georgia
   c. Mississippi
   d. Vermont
   e. New York

II. Funded by a Combination of Sources
   a. Connecticut
   b. Nebraska
   c. Pennsylvania
   d. Maine

III. State Funded
   a. North Carolina

I. Funded Primarily by Existing Gas Customers

INDIANA: Electric Infrastructure Modernization Plan

Timing	**April 30, 2013** – the Indiana state legislature passed Senate Enrolled Act 560 allowing utilities cost recovery of infrastructure upgrades and extensions through a tracker. **October 3, 2013** – NIPSCO filed a plan with the IURC. It was approved on April 30, 2014. **November 26, 2013** – Vectren filed a plan with the IURC. The order is still pending.

Reasoning/Justification for Changing the Cost Model

- Modernizing the natural gas system will promote safety and reliability and minimize future risk. NIPSCO's plan will also result in a direct local economic boost of $713 million and provide support for hundreds of direct and indirect jobs associated with infrastructure projects.

Description of Cost Model Approach[1]

How the Mechanism Works

- Indiana Code 8-1-39 allows electric and natural gas utilities to submit 7-year infrastructure improvement plans to the IURC for approval, pending a ruling within 210 days of a request. Utilities may request incremental rate increases every six months to pay for the projects. These rate adjustments are known as the Transmission, Distribution and Storage System Improvement Charge (TDSIC). Such rate increases are limited to no more than 2 percent of total retail revenues a year.
- In April 2014, the IURC approved NIPSCO's 7-year $713 million plan to modernize its natural gas transmission, distribution, and storage infrastructure.
- NIPSCO plans to pursue several projects over the next seven years, including:
  - Installing 80 miles of transmission pipeline and adding automated valve ($280 million);
  - Eliminating bare steel gas mains and replacing them with low-pressure systems ($61 million);
  - Constructing natural gas service to underserved areas ($99 million);
  - Retrofitting lines for in-line inspection ($46 million).

How the Mechanism is Funded

- NIPSCO's TDSIC tracker works similarly to a CapEx tracker in that the Company will receive a periodic automatic adjustment of its basic rates for 80 percent of approved capital expenditures and TDSIC costs. The remaining 20 percent of the costs will be recovered as part of the Company's next rate case. NIPSCO proposes to implement CWIP ratemaking treatment related to the recovery of financing costs incurred during the construction of capital projects.
- NIPSCO's 7-year plan has a total of about $713 million in natural gas investments through 2020, with a $55.3 million investment in 2014 and a $116.1 million investment in 2020.
- Average bills are projected to see a gradual average increase of approximately 1.4% annually through 2020, with no change in 2014 and a 1% annual increase in 2015.
- Construction is set to begin in late 2014 with the first rate increase of approximately 1.0 percent taking effect in 2015. The annual rate increase amounts from 2016 through 2020 would vary by year, ranging from 1.5 percent to 1.9 percent each year. The average annual percentage increase over the 7-year term is 1.4 percent. NIPSCO plans to file its first TDSIC natural gas rate adjustment request in September 2014.

Results to Date

- NIPSCO's plan was approved on April 30, 2014. Results of the program have not yet been released.

[1] Information associated with NIPSCO Plan

GEORGIA: Strategic Infrastructure Development and Enhancement Program

Atlanta Gas Light Company (AGL) initiated the Strategic Infrastructure Development and Enhancement (STRIDE) program in 2009 as part of a ten-year system reinforcement program to meet Georgia customers' needs for natural gas. The first phase of the program improved capacity in six counties and added a new supply point by tapping into an interstate gas line. The second phase, beginning in 2013, involves the installation of new pipes and other facilities to improve the capacity and pressure in high-growth areas of the state.

Timing

June 12, 2009 – AGL filed a Petition for Approval of the Strategic Infrastructure Development and Enhancement (STRIDE) Program, which provides for a rider on customer bills that allows AGL to recover costs associated with infrastructure replacement, as well as infrastructure expansion relating to customer growth and economic development.

December 12, 2013 – the PSC approved the second phase of STRIDE, including a $46 million expansion of the company's customer growth program to expand its natural gas system into communities throughout the state that are unserved or underserved.

Reasoning/Justification for Changing the Cost Model

- The STRIDE program will encourage safety and reliability.

Description of Cost Model Approach

How the Mechanism Works

- AGL's STRIDE program serves as an umbrella for four separate programs:
  - Pipeline Replacement Program (PRP), 1998: focuses on traditional infrastructure replacement.
  - Integrated System Reinforcement Plan (i-SRP), 2009: allows the Company to replace existing infrastructure or install additional infrastructure to ensure reliability on peak days.
  - Integrated Customer Growth (i-CGP), 2010: employs incentives to attract new customers to connect to the AGL natural gas system. The company installs mains along strategic corridors to encourage residential development and firm commercial and industrial customer growth.
  - Vintage Plastic Replacement (i-VPR), 2013: involves replacing 750 miles of older, plastic pipe with newer, technologically advanced plastic pipe to ensure safety and reliability.

How the Mechanism is Funded

- The actual costs associated with recovery of the i-SRP project investments and the PRP program costs are recovered through a monthly levelized surcharge collected from all firm customers.
  - Residential customer's rates increased $0.39 per month on October 1, 2009 to fund the STRIDE program, and subsequently increased another $0.40 per month on October 1, 2010.
  - On December 12, 2013, the Georgia Public Service Commission approved the second phase of AGL's STRIDE program, including a $46 million expansion of the Customer Growth program to expand the natural gas system into communities throughout the state that are currently underserved. The STRIDE program extension will increase customer bills by $0.48 beginning January 2015and another $0.47 in January 2017.
- The recovery period for STRIDE spans through September 22, 2025.

Results to Date

- AGL reports system extensions associated with integrated customer growth in the program's first phase amounted to $45 million.
- The Company must file a copy of its i-SRP Plan every three years and include a ten-year forecast of the customer growth and natural gas demand for its system for informational purposes.

MISSISSIPPI: Supplemental Growth Rider

Timing

February 5, 2013 – Atmos Energy Corporation filed a Supplemental Growth Rider (SGR) with the Mississippi Public Service Commission.

July 2013 – The Commission approved the rider, and it became effective at that time.

Reasoning/Justification for Changing the Cost Model

- Supporting economic development and job creation by providing an incentive to extend gas service to projects previously viewed as economically infeasible.

Description of Cost Model Approach

How the Mechanism Works

- The Supplemental Growth Rider (SGR) allows Atmos to invest $5 million annually in industrial growth projects without requiring project-specific Commission approval. It allows the company to earn a supplemental return on equity of 3 percent on the rate base associated with such gas growth projects (in addition to the performance-based benchmark return provided for in the company's annual Stable Rate Evaluation).
- The SGR is intended to encourage industrial development and job creation by providing an incentive for Atmos to extend gas service for industrial projects which are not feasible for it to fund, but beneficial to the potential economic development of the State of Mississippi.
- Atmos Energy works closely with the Mississippi Development Authority (MDA), as well as regional and local economic development authorities, to identify potential investment projects.

How the Mechanism is Funded

- Atmos proposes to invest $5 million annually in gas service projects previously viewed as economically infeasible. In return, Atmos earns a supplemental ROE of 3 percent on this investment in addition to the ROE provided for in Atmos' annual Stable Rate Evaluation.
- The program funds industrial gas growth investments for the project's first ten years in service. New gas revenues generated by such investments help recoup the cost of the program.
- The rate impact of this proposal is pro-ratably spread amongst all customer classes in the same manner as Atmos' Stable Rate Factor.

Results to Date

- Atmos Energy announced a multi-phase, multi-year expansion of its facilities in the Meridian area, which contains three industrial parks. In addition to constructing new facilities, existing facilities will also be reinforced to allow for increased natural gas demand. Atmos expects to invest $7.5 million in Phase 1 of the project. The timing and costs of the other two phases will be determined by the timing of demand and cost of materials. The company anticipates it will take six years to complete all aspects of the project.

VERMONT: System Expansion and Reliability Fund

Timing

February 7, 2011 – Vermont Gas Systems (VGS) filed a request for an accounting order with the Vermont Public Service Board (VPSB) to establish the Vermont System Expansion and Reliability Fund to meet planning and development costs associated with VGS' potential expansion of service into new market areas.

September 2011 – The Vermont Public Service Board approved the System Expansion and Reliability Fund for VGS.

Reasoning/Justification for Changing the Cost Model

- The goal of the program is to reduce overall energy costs in Vermont as well as to improve reliability of the existing distribution and transmission system. This mechanism enhances the economic viability of extending service.

Description of Cost Model Approach

How the Mechanism Works

- The System Expansion and Reliability Fund helps facilitate the build-out of the VGS gas system by smoothing the rate trajectory that would otherwise be expected if the expansion project were constructed.
- The Fund supports future pipeline projects that: (1) reduce the overall cost of energy in the state; (2) increase existing pipeline system capacity; (3) expand the number of Vermont communities that can benefit from natural gas; and (4) improve the reliability of existing transmission and distribution infrastructure.

How the Mechanism is Funded

- The Expansion Fund is funded through deferments and escrow savings that would have otherwise gone to ratepayers from an anticipated rate reduction in its quarterly Purchase Gas Adjustment under VGS's alternative regulation plan. The Fund generates approximately $4.4 million annually, which represents about $5.40 per month for the average residential heating customer.
  - VGS collects money from ratepayers to be used to offset future rate increases that may arise from the potential system expansion.
  - The company tracks all customers' payments in the Expansion Fund, meaning that if the expansion did not move forward, the contents of the Fund would have been returned to the specific customers that paid into it.

Reasoning/Justification for Changing the Cost Model

- The goal of the program is to reduce overall energy costs in Vermont as well as to improve reliability of the existing distribution and transmission system. This mechanism enhances the economic viability of extending service.

Results to Date

- The first proposed project was an expansion of natural gas service to Addison County that increases capacity and improves reliability of the existing pipeline system in Chittenden and Franklin Counties.

NEW YORK: Energy Highway

Timing

October 2012 – Governor Cuomo's Energy Highway Blueprint issued that proposed allocating up to $500 million of funds for expansion of natural gas distribution services and increased efficiency and reliability of these services.

May 22, 2013 – Technical Conference on Expansion of Natural Gas held by New York Public Service Commission (NYPSC).

May 16, 2013 – SB5536B proposed and recommitted to the Senate Energy and Telecommunications Committee to aid in the expansion of natural gas services in an economically and environmentally safe way.

January 2014 – Draft of 2014 New York State Energy Plan Released; period for receiving public comment ended in May 2014. The final version is expected in the Fall.

June 20, **2014 –** SB3356B committed to the Rule Committee in the Senate.

Reasoning/Justification for Changing the Cost Model

- The purpose of SB5536B is to promote economic development by the creation of jobs, create energy cost savings, and improve energy efficiency. The bill also aims to mitigate environmental impacts by reducing particulate matter and emissions.
- The 2014 NY State Energy Plan was created in hopes of encouraging economic development by reducing reliance on petroleum products for primary heating sources in buildings. The Plan promotes using clean alternatives to oil, expanding access and infrastructure for natural gas distribution, and pursuing research to mitigate gas leakage.

Description of Cost Model Approach

How the Mechanism Works

SB5536B

- Expands permit applications to streamline the permitting process for expansion of natural gas distribution infrastructure by facilitating contacts with state agencies and local governments.
- Requires a study on Clean Natural Gas Heat in Public Buildings for the conversion to natural gas heating by the Commission of General Services when public buildings need to upgrade their boiler.

2014 NY State Energy Plan, Initiative 9 requires:

- The Department of Public Service (DPS) to encourage oil-to gas conversions by collaborating with other state agencies and regulated gas utilities to accelerate investments in natural gas distribution.
- The Department of Environmental Conservation (DEC) to evaluate regulations to limit methane emissions from natural gas compressor stations on intrastate pipelines.

How the Mechanism is Funded

- SB3356B is funded by customer surcharges and RGGI monies
  - o 25 percent of revenue generated by SEC surcharges (system benefit charge obtained by utilities from heating customers) helps to create a revolving loan fund for conversions.
  - o A natural gas expansion mitigation fund uses RGGI monies for a revolving loan fund for consumer converting to natural gas.

Results to Date

- SB5536B and the 2014 NY State Energy Plan are currently pending approval.

II. Funded by a Combination of Sources

CONNECTICUT: Comprehensive Energy Strategy

Timing

February 2013 – Governor Malloy announced the Comprehensive Energy Strategy, which calls for regulatory changes to enable potential gas customers to have their connections financed by the state's utilities and repaid through added revenues of new customers.

July 8, 2013 – State legislature approves Public Act No. 13-298 concerning implementation of Connecticut's Comprehensive Energy Strategy and various revisions to the energy statutes.

July 26, 2013 – The three natural gas utilities filed a joint proposal with the state regulator ("PURA") outlining a rate plan to finance the connection of 280,000 new customers over the next 10 years. The plan targets potential customers who are off-main as well as potential customers that are within 150 feet of an existing main.

November 22, 2013 – PURA approved joint expansion plan.

Reasoning/Justification for Changing the Cost Model

- PURA's decision acknowledges broader societal benefits that gas expansion would enable, such as: increased employment, local economic development, environmental benefits, and transit-oriented goals.
- The ruling denied the gas companies' request for additional financial incentives to meet customer conversion targets and other policy objectives, but indicates PURA's willingness to revisit the issue if the companies demonstrate tangible cost savings and other efficiencies under the plan.

Description of Cost Model Approach

How the Mechanism Works

- Under the joint proposal, rates would: (1) spread connection costs over 25 years; (2) eliminate a CIAC for potential customers that are ≤150 ft. (~46 meters) to gas mains and; (3) make other rate changes to encourage a large-scale switch to natural gas.
  - PURA's ruling eases viability criteria for gas companies, lengthening the payback period to 25 years and introducing a "portfolio" approach to gas extensions. Whereby a project can begin construction as long as 60% of customers necessary to make the project viable have committed.

How the Mechanism is Funded

- New customers added after January 1, 2014 will be charged a monthly premium over current rates to offset the incremental expansion costs (rather than a one-time upfront payment).
  - On-main customers (within 150 ft.) added after January 1, 2014, will pay a ten-year, 10% premium on the distribution component of standard rates.
  - Off-main customers added after January 1, 2014, will pay a ten-year, 30% premium on the distribution component of standard rates.
  - After the initial ten years of service, new customers return to standard rates, with the exception of customers who are far from the main or have complex construction requirements.
- Non-firm margin credits, or revenue earned through interruptible and off-system sales, will be used to offset expansion costs (if the new customer surcharge and non-firm margin revenue prove insufficient to cover ongoing expansion costs, a system expansion reconciliation charge on existing customer bills will be used to make up the difference).

Results to Date

- Joint Expansion Plan became effective on January 1, 2014; too early to report on progress.

NEBRASKA: Rural Infrastructure Development Program

Timing

September 2011 – the Nebraska Public Service Commission ("NPSC") expanded SourceGas' Extra Construction Allowance.

April 10, 2012 – the Nebraska legislature passed Legislative Bill 1115 providing for construction and operation of natural gas infrastructure in underserved or unserved rural areas of the state.

Reasoning/Justification for Changing the Cost Model

- The purpose of the program is to provide reliable natural gas pipeline infrastructure and service to expand and diversify Nebraska's economy, resulting in greater employment opportunities, the creation and expansion of businesses and industries, as well as new and expanded sources of tax revenue.

Description of Cost Model Approach

How the Mechanism Works

- Legislative Bill 1115 streamlines the regulatory review process and allows utilities to spread costs to all ratepayers. It requires stakeholders (utilities, municipalities, local businesses, investors) to put together a plan for infrastructure expansion, pending approval by the NPSC.
- SourceGas is also permitted to collect a Regular and Extra Construction Allowance as part of its rates. An Extra Construction Allowance for new main and/or service line extensions offered to new Customers within the service territory is available in an amount up to a maximum of the cost of connection.

How the Mechanism is Funded

- Legislative Bill 1115 streamlines the regulatory review process and allows utilities to spread costs to all ratepayers. It requires stakeholders (utilities, municipalities, local businesses, investors) to put together an infrastructure expansion plan, pending NPSC approval.
- Funding for the rural infrastructure development program includes, but is not limited to: (1) Proposed rate increases for customers of the electing city or cities and within **a city's** extraterritorial zoning jurisdiction; (2) city funds, including funds from the Local Option Municipal Economic Development Act, which may be used to pay for consultants, issue bonds, lower proposed rate increases, or otherwise provide financing; and (3) contributions from direct customers or other sources, including, but not limited to, state or federal grants or loans.
- SourceGas' Extra Construction Allowance advances to participants up to $5,000 of costs over the amount. It is funded by spreading the repayment obligation associated with that advance for up to 15 years through a $50 per month payment added to their natural gas bill.

Results to Date

- Not immediately available.

PENNSYLVANIA

Timing

March 11, 2013 – State Legislature adopted Senate Resolution No. 29, requiring the Center For Rural Pennsylvania to study current gas distribution infrastructure and look for areas of improvement and/or expansion concerning the residential, commercial, and industrial sectors.

April 4, 2013 –UGI proposed the Growth Extension Tariff (GET), which spreads the costs of building mains to new customers who would be connecting to it. This tariff will be funded by UGI at $15 million per year for 5 years.

June 12, 2013 – The Senate passed the Natural Gas Consumer Access Act (SB738), which requires every natural gas distributor to submit a biannual expansion plan to PUC, and the Alternative Energy Investment Act (SB739), which provides $15 million in grants to public services to convert to natural gas.

February 20, 2014 – UGI GET approved.

April 23, 2014 –Columbia Gas submits a proposal for a 4-year pilot rider New Area Service (NAS), which would spread current upfront costs of new natural gas service over 20 years and would not exceed $35 on customer bills. The proposal is currently suspended until October 28, 2014 due to a complaint filed by the OCA. The proposal is suspended until the Pennsylvania Public Utilities Commission can conduct an investigation.

Reasoning/Justification for Changing the Cost Model

- Senate Resolution 29 is driven by increased economic development by means of job creation and cheaper, better energy for Pennsylvania.
- SB738 and 739 help to promote more widespread use of natural gas which will lower energy costs by switching from more expensive fuels to low-cost natural gas and by expanding natural gas distribution infrastructure.
- The GET tariff will help to lower energy costs for those who are currently using other primary sources of energy. By implementing this tariff, UGI will be able to expand their distribution infrastructure without increasing rates for existing customers and without burdening new customers with large upfront costs.
- The NAS Rider will help to lower energy costs by lengthening the time in which upfront costs are paid, which encourages more customers to switch to natural gas.

Description of Cost Model Approach

How the Mechanism Works

- Senate Resolution 29 studies the infrastructure and economic situation of those currently not using natural gas as their fuel source. The Center for Rural Pennsylvania has been tasked with studying: (1) the demand for natural gas service in unserved and underserved areas; (2) the price consumers are willing to pay for access or conversion to natural gas service; (3) any regional differences in consumer demand and willingness to pay for natural gas service; and (4) any other relevant economic information on the cost and benefits related to expanding natural gas distribution infrastructure.
- SB739 allocates $15 million to schools, hospitals, and small businesses to convert to natural gas as their primary energy source. This $15 million is in the form of grants that provide up to 50% of the project cost. Priority is given to applications that result in adjoining commercial or residential properties utilizing natural gas.
- UGI's GET is a five-year program that creates surcharges for new customers over an extended period of time to avoid the high upfront costs of converting to natural gas.
- The NAS Rider is a four-year program that reduces upfront construction costs through monthly surcharges of $35 or less over 20 years.

How the Mechanism is Funded

- Senate Resolution 29 and SB738 do not require funding.

- SB739 is funded through grants.
- UGI's GET is funded by the 3 UGI companies at an average of $15 million per year for 5 years, and by surcharges for new residential and commercial customers.
- The NAS Rider is funded by the Columbia Gas Company by no more than $1 million per year for 4 years.

Results to Date

- Senate Resolution 29 returned a study in 2013, which found that "half or more Pennsylvania households would not connect to a natural gas line regardless of the upfront costs or payback period on the investment." Several different attitudes explain customers' reluctance to convert: concern about potential gas price increases in the future, the hassle of installing new heating equipment and a supply line, and an inability to afford upfront costs.
- Results of UGI's GET program are in the form of annual costs savings from the transition from other energy sources to natural gas. As of June 2014, these results include:
  - Natural Gas v. Propane: $1,200-1,700 in savings
  - Natural Gas v. Electric: $900-1,400 in savings
  - Natural Gas v. Oil: $800-1,200 in savings

MAINE	
Timing	**June 27, 2013** – the Maine Legislature overrode the Governor's veto of the Omnibus Energy Bill, which aims at expanding the state's natural gas infrastructure and increasing energy efficiency funding, among other measures. The bill allows the state to spend $75 million/year to expand natural gas pipeline capacity to lower energy costs. **April 12, 2014** – Legislative Directive 1621 instructs the Maine legislature to include a description of the state's natural gas expansion activities in future State Energy Plans.

Description of Cost Model Approach

- Unlike other states, Maine does not have natural gas franchise areas that protect utilities from outside competition. As a result, four Maine LDCs compete with one another and have significant development plans to expand service into remote or unserved communities.
    - Summit Natural Gas has begun the $350 million Kennebec Valley Project aimed at expanding transmission and distribution pipeline to serve 15,000 homes and businesses in 17 communities. The network will be anchored by Sappi Fine Paper Mill in Skowhegan, ME. The company also received approval for a $42 million project to provide natural gas distribution service to three towns in southern Maine next year.
    - Maine Natural Gas is currently building a $23 million pipeline into Augusta, with the goal of reaching 70 percent of homes and businesses.
    - In late October 2013, Bangor Natural Gas announced plans to construct a five-phase, $7.5 million natural gas pipeline to Lincoln, Maine.
    - Unitil has plans to increase its number of customers from 74,000 to 92,000 by 2016 through additions and conversions.
- Maine's growing gas demand has also led several interstate pipelines – such as Algonquin Gas Transmission, Iroquois Gas Transmission, Maritimes & Northeast Pipeline, Portland Natural Gas Transmission System, and Tennessee Gas Pipeline Company – to consider expansion into New England to address upstream pipeline constraints.
- A law signed in 2012 authorizes the Finance Authority of Maine to issue bonds for the development of the state's natural gas infrastructure. However, expansion of gas lines is primarily funded by ratepayers.
- In January 2013, the Maine PUC approved a rate plan for Summit Natural Gas that includes: (1) delivery rates; (2) a capped Annual Adjustment; (3) a provision to recover the Cost of Gas; and (4) an incentive plan. This Plan allows the Company to reach all residential and commercial customers without requiring CIAC to support construction of Summit's lines.
- There is an ongoing debate in the legislature over how much the government should subsidize natural gas conversions, and where the money should come from.

III. State Funded

NORTH CAROLINA: Clean Water and Natural Gas Critical Needs Bond Act

Timing

July 8, 1991 – Public Utilities Act enacted.

September 9, 1998 – North Carolina Clean Water and Natural Gas Critical Needs Bond Act of 1998 passed.

Reasoning/Justification for Changing the Cost Model

- The purpose of the North Carolina Clean Water and Natural Gas Critical Needs Bond Act of 1998 is to reduce the cost of "uneconomic line extensions" of natural gas facilities.

Description of Cost Model Approach

How the Mechanism Works

- The North Carolina Clean Water and Natural Gas Critical Needs Bond Act of 1998 provides $200 million in bonds allocated as "grants, loans, or other financing to natural gas local distribution companies, persons seeking natural gas distribution franchises, State or local government agencies, or other entities for construction of natural gas facilities."
- Chapter 62 of North Carolina's Statues and Codes entitled "Public Utilities Act" also provides for natural gas expansion legislation:
  - o Declaration of Policy (62-2 (a)(9)) "To facilitate the construction of facilities in and the extension of natural gas service to unserved areas in order to promote the public welfare throughout the State and to that end to authorize the creation of expansion funds for natural gas local distribution companies or gas districts to be administered under the supervision of the North Carolina Utilities Commission";
  - o Natural Gas Expansion (62-158);
  - o Additional Funding for natural gas expansion (62-159).

How the Mechanism is Funded

- The 1998 North Carolina Clean Water and Natural Gas Critical Needs Bond Act are funded by state bonds.
- Public Utilities Act 62-158b states that sources of funding for LDC's natural gas expansion fund may include the following:
  - o (1) Refunds to an LDC from their natural gas and transportation suppliers.
  - o (2) Expansion of customer surcharges by LDCs, provided that these surcharges take into consideration prices of alternative sources of energy and are considered reasonable and competitive. They must not be greater than 15 cents per dekatherm.
  - o (3) Other sources approved by the North Carolina Utilities Commission.

Results to Date

- In 2006 $200 million was allocated to 2 recipients: Frontier Energy (Warren County Project and Ashe County Project) and Piedmont Natural Gas.
  - o From 2011-2013, Frontier added nearly 195,000 feet of pipe and had a 59 percent increase in the number of customers served. Frontier currently has a proposal for a 20 mile pipeline to be constructed in 2014/2015 that extends into Allegheny County.
  - o Piedmont is currently planning to install 25 miles of pipeline in the Brices Creek Community.
- In 1990 18.6% of houses were fueled by natural gas and by 2010 24.9% were fueled by natural gas.
- North Carolina's 2014 Report on System Expansion found that since G.S. 62-36A became effective in 1989:
  - o 34 unserved counties are now served;
  - o $510 million has been invested in natural gas infrastructure;
  - o Service is now available in 96/100 counties, with no plans to extend service to last 4 counties.

APPENDIX B – FINANCIAL SUPPORT PROGRAMS FOR CANADIAN GAS EXPANSION PROJECTS

PREPARED BY THE CANADIAN GAS ASSOCIATION

Canadian Government Pipeline Expansion Programs

Name of Program	Timeframe	Province	Lead Department	Funding	Partners	Rationale for Program
Distribution System Expansion Program (DSEP)	1980-1984	Ontario	Department of Energy, Mines and Resources (EMR)	The program had spent or committed about $100 million from the federal government by March 1983.	Union Gas	The key criteria for funding such projects were the lack of financial viability and the volume of oil that gas would displace.
Canada Oil Substitution Program (COSP)	1980-1985	Across Canada	Department of Energy, Mines and Resources (EMR)	This program provided federal government grants to homeowners who converted from oil to natural gas. A total of $715 million in government grants funded 987,555 conversion projects.		This program encouraged oil customers to covert to natural gas. 90,000,000 GJ/yr of oil energy was substituted.

Name of Program	Timeframe	Province	Lead Department	Funding	Partners	Rationale for Program
Market Development Incentive Payments (MDIP)	From the date of signing a contribution agreement as a result of the announcem-ent of the Request for Project Proposals to October 31, 2016.	Alberta	Natural Resources Canada	Financial support for projects is constrained by the total amount available, the timeframe for projects and project selection criteria. Total funding available is $1.2 million until October 31, 2016. Program expenditures in fiscal 1982/83 were $33.8 million and in 1983/84, $82.1 million for the programs - DSEP, ICAP, GMAP, and CNG, with the federal government making up the $5.3 million deficit in 1982/83 and the $70.1 million deficit in 1983/84.		To develop and support the expansion of Alberta natural gas in Canada. A major goal of the MDIP Fund is to undertake projects to demonstrate alternative applications of natural gas.
Vallée-Jonction to Thetford Mines	2012	Quebec	Natural Resources Canada	The $25 million project was funded partially by the federal government, with an investment of $18 million, and partially by Gaz Metro-QDA with a $7 million investment.	Gaz Metro, Régie de l'énergie	This pipeline will greatly enhance the competitiveness of local businesses, retailers, and institutions. As well, many commercial and industrial customers will be converting from fuel oil to natural gas. These conversions to natural gas will help reduce fuel oil consumption by approximately eight million litres, which represents a GHG emissions reduction of about 7,000 tonnes of carbon dioxide-equivalent.

Name of Program	Timeframe	Province	Lead Department	Funding	Partners	Rationale for Program
Red Lake	2012	Ontario	Natural Resources Canada	This $40 million natural gas pipeline expansion project was funded cooperatively by the federal and provincial governments, Goldcorp, the Municipality of Red Lake and Union Gas. Goldcorp $25,600,000.00 Union Gas $1,700,000.00 ____________________ Phase 1 $27, 300,000.00 Province $4,900,000.00 FedNor $2,700,000.00 GoldCorp $2,150,000.00 Union Gas $8,800,000.00 ____________________ Phase 2 $19,300,000.00	Union Gas, Link Line, Goldcorp, FedNor	This expansion provided the residents and businesses of the Municipality of Red Lake with clean, affordable, and reliable natural gas service. This project has supported the creation of over 100 jobs, financially benefited and stimulated the local economy, and will most certainly encourage further investment in Northern Ontario.

Name of Program	Timeframe	Province	Lead Department	Funding	Partners	Rationale for Program
Federal Natural Gas Laterals Program Pipeline from Grand-Mere to the Saguenay-Lac St Jean region.	1984	Quebec	Natural Resources Canada	The project was financed by the federal Natural Gas Laterals Program, established in 1982, which paid the total cost of all laterals built in Quebec in the period 1982-85. Ottawa provided Gaz Inter-Cite with a grant of $225 million as part of the 1982 agreement between Ottawa and Quebec City whereby the federal government footed the bill, estimated at $465 million, for natural gas pipeline extensions in the province. Gaz Inter-Cite spent $500 million to build up natural gas distribution networks in the cities located along the pipeline. And another $140 million to service the Eastern Townships as well as the Trois Rivieres-Shawinigan and Becancour regions. The federal government subsidized industrial conversions to natural gas by footing 50% of the conversion bills.	Gaz Metro, Gaz Inter-Cite Quebec	Access to natural gas is crucial for several Québec industrial businesses. Many industries creating employment in Québec, such as pulp and paper, aluminum, smelter and cement industries need the energetic value of natural gas.

Name of Program	Timeframe	Province	Lead Department	Funding	Partners	Rationale for Program
Vancouver Island and the Sunshine Coast	1983	British Columbia	Natural Resources Canada	The $485-million project covering the transmission pipeline, local distribution facilities, and conversions was to have a private sector investment of $255 million. The federal government was to contribute $100 million towards the capital cost and a $50 million interest-free loan. The B.C. government was to provide $55 million to assist in energy conversions and an interest free loan of $25 million and, in addition, a $70 million repayable rate stabilization facility designed to backstop project work in the early years.	The private sector sponsor of the project was Pacific Coast Energy Corporation. Fortis B.C.	A task force report completed in February 1983 had concluded that natural gas would be the most cost-effective future energy option for most Vancouver Island communities, that the net economic benefits of such a project from a national perspective would be $700 million. The gas pipeline project was expected to generate a variety of economic benefits. These included: -Increased ability of B.C.-based companies to produce products using natural gas as a fuel or feedstock, -Increased employment from gas production in northeastern British Columbia based on 10% increase in natural gas sales, -Royalties to the province of about $95 million over 20 years, -Property taxes to municipalities from both the transmission line ($1.5 million per year) and distribution systems ($30 million over ten years), -Plus the associated employment (construction, installation and maintenance).

Name of Program	Timeframe	Province	Lead Department	Funding	Partners	Rationale for Program
Canada- Manitoba Infra-Structure program Southwestern Manitoba	1994-1997	Manitoba	Natural Resources Canada	The total system cost was about $21.5 million financed by: Province $5.7 million Canada $5.7 million Municipalities $5.7 million Centra Gas $3.7 million Customers $0.5 million Manitoba and Canada contributed through the federal provincial Infra-Structure Program. The Municipalities issued debentures. Customers paid $300 each to participate.	Manitoba Hydro, Centra Gas	The major benefits to the towns and the rural municipalities include: -Savings on energy costs to publicly funded buildings. e.g., schools, hospitals, rinks, pools, etc. -Opportunities to build or attract industries that require this type of energy source. e.g., ethanol plants, straw processing, hog operations, pasta plants. -Savings to existing businesses, allowing increased competitiveness and assisting in long term viability of town/service centers. -Increased assessment in every municipal jurisdiction, creating an assured increase in future tax revenue. -Increased tax revenue in all municipal jurisdictions resulting from increased assessments. -Immediate increase in revenue through taxation of any branch lines constructed that are not included in the financing plan.

Name of Program	Timeframe	Province	Lead Department	Funding	Partners	Rationale for Program
Canada Agri-Infrastructure Program (CAIP) Interlake Region	2000	Manitoba	Natural Resources Canada	The Interlake system was installed only because of the government assistance for capital costs. In the view of local observers, it would not have happened otherwise. The federal government introduced a post Crow rate infrastructure assistance program through which the area got $2.35 million in 1998 towards the $7.3 million system. Manitoba contributed a similar amount; municipalities contributed 15% or $1.1 million, financed by about 50% from incremental tax revenue from the distribution system and 50% from a new tax rate. This also included collecting some of the school taxes that are paid as part of property taxes.	Manitoba Hydro, Interlake Natural Gas Co-op	The arrival of natural gas will help these communities attract new businesses and many Interlake residents will now have the same home heating options enjoyed in other parts of the province. This is part of the commitment to upgrading vital infrastructure throughout Manitoba.
Parry Sound	2000	Ontario	Natural Resources Canada	The $16.5 million project was funded by Union Gas $9.7 million (59%), the Town of Parry Sound and the Township of Seguin $800 thousand (5%), the Federal Government $3 million (18%) (through HRDC) and the Province of Ontario's Northern Ontario Heritage Fund $3 million (18%).	Union Gas, Canada's Human Resources Development Center	Funding to expand the natural gas pipeline network into rural Ontario will make low-cost energy available to a greater number of Ontario citizens, including farms, and give them a better competitive advantage. In addition to home heating requirements, farm businesses use significant amounts of energy to heat barns, run grain dryers and ventilate buildings.

Canadian Government Pipeline Expansion Program Details

Distribution System Expansion Program (DSEP)

In the early 1980's, the expansion of the natural gas distribution network was stimulated by federal government programs designed to reduce Canada's dependence on imported oil (Butler et al, 1987). One of these programs, the Distribution System Expansion Program (DSEP), administered by The Department of Energy, Mines and Resources (EMR) provided funds to the gas utilities of Ontario, in the form of contributions in aid of construction, to assist in the expansion of their distribution system. DSEP was designed to facilitate specific types of system expansion projects. Gas utilities submitted proposals for system expansions to the Gas Branch where they were reviewed (Office of the Auditor General of Canada, 1983). When specified selection criteria were met, a contribution of various proportions to the capital costs of the expansion was made. The key criteria for funding such projects were the lack of financial viability and the volume of oil that gas would displace (Butler et al, 1987). The program had spent or committed about $100 million by March 1983 (Office of the Auditor General of Canada, 1983).

Canada Oil Substitution Program (COSP)

Another federal government program, the Canada Oil Substitution Program (COSP), provided a grant to homeowners who converted from oil to natural gas. This program encouraged oil customers to covert to natural gas (Butler et al, 1987). A total of $715 million in government grants funded 987,555 conversion projects (Spears, 1987). 90,000,000 GJ/yr of oil energy was substituted with this program.

These EMR programs, DSEP and COSP, which encouraged expansion of the natural gas distribution system, were phased out in 1984 and 1985 (Butler et al, 1987).

Market Development Incentive Payments (MDIP)

As a result of the September 1, 1981 Canada/Alberta Agreement on Energy Pricing and Taxation and the subsequent Agreement on Gas Pricing and Market Development Payments of November 25, 1981, the MDIP Fund was established by the Governments of Canada and Alberta to develop and support the expansion of Alberta's natural gas (Natural Resources Canada, 2012). Eligible recipients of the MDIP fund include: for-profit and non-profit organizations who are legally incorporated or registered in Canada, including but not limited to electrical and gas utilities, industry associations and research associations, Canadian academic institutions, Canadian provincial, territorial and regional and municipal governments and their departments and agencies, but excluding sole-proprietorships (Natural Resources Canada, 2013). The program was to extend from November 1981 to January 1987 (Toombs, n.d.). Four federal programs were funded, in part, from MDIP receipts: the Distribution System Expansion Program (DSEP); the Industrial Conversion Assistance Program (ICAP); the Gas Marketing Assistance Program (GMAP); and the Compressed Natural Gas (CNG) Fuelling Station and Vehicle Conversion Programs. MDIP earnings in the period November 1, 1981 to October 31, 1983 were $31.7 million. A further $14.0 million was earned by March 31, 1984. Program expenditures in fiscal 1982/83 were $33.8 million and in 1983/84, $82.1

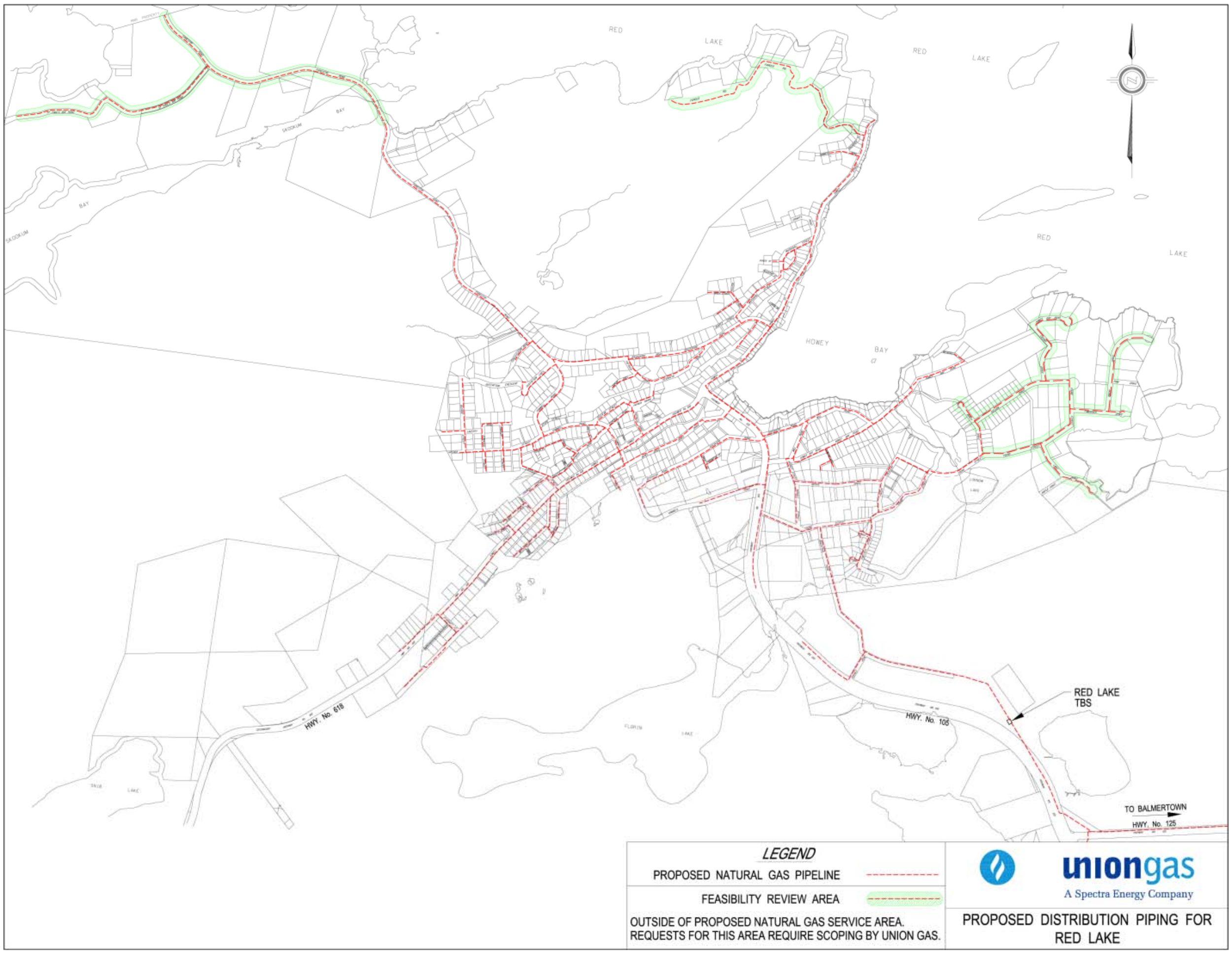
million for the above noted programs - DSEP, ICAP, GMAP, and CNG, with the federal government making up the $5.3 million deficit in 1982/83 and the $70.1 million deficit in 1983/84.

Vallée-Jonction to Thetford Mines, Quebec

In November 2012, Gaz Metro extended its natural gas pipeline approximately 80 kilometers from Vallée-Jonction to Thetford Mines (Gaz Metro, 2012). This extension serves the communities of Vallée-Jonction, Saint-Frédéric, Tring-Jonction, Sacré-Cœur-de-Jésus, East Broughton, Saint-Pierre-de-Broughton and Thetford Mines, including the Black Lake area. This $25 million project was funded partially by the federal government, with an investment of $18 million, and partially by Gaz Metro-QDA with a $7 million investment (Gaz Metro, 2013). Canada's Prime Minister Stephen Harper said "This pipeline will create jobs and economic opportunities in the region, while providing local businesses and institutions with an affordable source of energy." (Pipelines Internationl, 2010). This pipeline will greatly enhance the competitiveness of local businesses, retailers, and institutions (Canadian Gas Association, 2013). As well, many commercial and industrial customers will be converting from fuel oil to natural gas. These conversions to natural gas will help reduce fuel oil consumption by approximately eight million litres, which represents a GHG emissions reduction of about 7,000 tonnes of carbon dioxide-equivalent (Monahan, 2012).

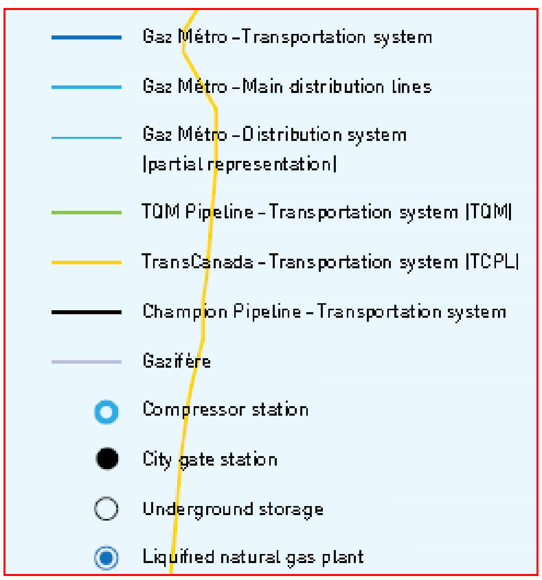
Red Lake, Ontario

In October 2012, a $40 million natural gas pipeline expansion project was funded cooperatively by the federal and provincial governments, Goldcorp, the Municipality of Red Lake and Union Gas (Union Gas, 2012). This pipeline provides service to residents of Balmertown, Cochenour, and Red Lake. Link Line, Union Gas' experienced construction alliance partner, worked closely with the company on the project. Throughout it, the company's goal was environmental conservation and minimizing the impact of construction on the surrounding environment. For example, where practical, pipelines were installed using an underground drilling technique that minimized surface disturbance. According to Michael Gravelle, Ontario Natural Resources Minister, this expansion provided the residents and businesses of the Municipality of Red Lake with clean, affordable, and reliable natural gas service. This project has supported the creation of over 100 jobs, financially benefited and stimulated the local economy, and will most certainly encourage further investment in Northern Ontario (Canadian Gas Association, 2013).



Grand-Mere to the Saguenay-Lac St Jean region, Quebec – Natural Gas Laterals Program (NGLP)

In December, a new natural gas pipeline, funded by the federal government in an amount of $175 million, was completed over a 333 km route between Grand-Mere and La Baie in Quebec to connect the Saguenay - Lac Saint-Jean region with the province's natural gas network. The project was financed by the federal Natural Gas Laterals Program, established in 1982, which paid the total cost of all laterals built in Quebec in the period 1982-85. Ottawa provided Gaz Inter-Cite with a grant of $225 million as part of the 1982 agreement between Ottawa and Quebec City whereby the federal government footed the bill, estimated at $465 million, for natural gas pipeline extensions in the province (Roy, 1983). Gaz Inter-Cite spent $500 million to build up natural gas distribution networks in the cities located along the pipeline, and another $140 million to service the Eastern Townships as well as the Trois Rivieres, Shawinigan and Becancour regions. The federal government subsidized industrial conversions to natural gas by footing 50% of the conversion bills. Access to natural gas is crucial for several Québec industrial businesses. Many industries creating employment in Québec, such as pulp and paper, aluminum, smelter and cement industries need the energetic value of natural gas.



Vancouver Island and the Sunshine Coast, British Columbia

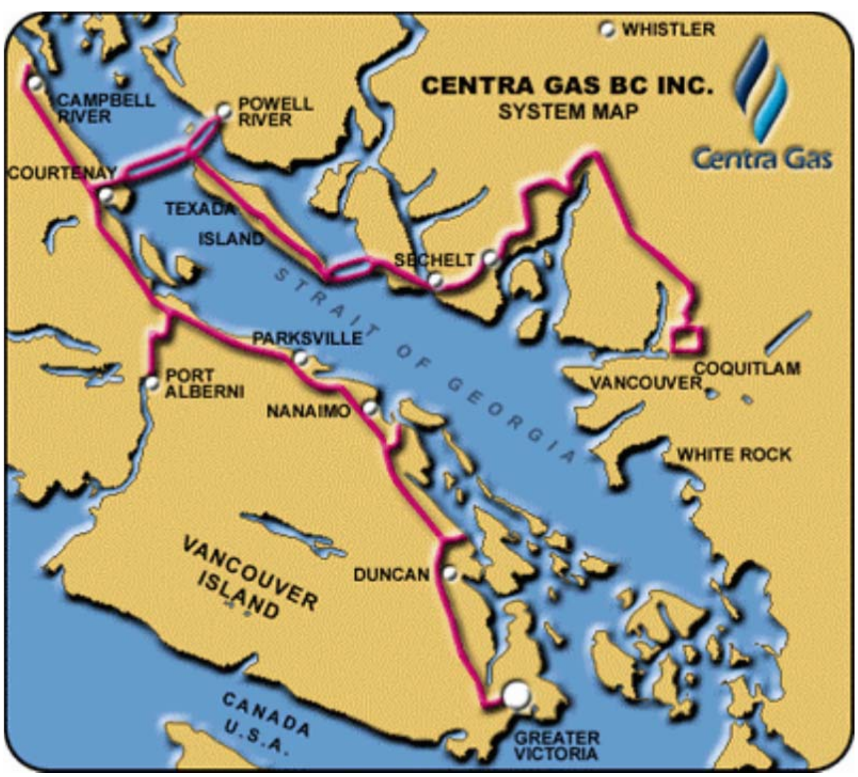
A task force report completed in February 1983 had concluded that natural gas would be the most cost-effective future energy option for most Vancouver Island communities, that the net economic benefits of such a project from a national perspective would be $700 million, and that the federal government should provide financial support for a pipeline to Vancouver Island (Gardner Pinfold Consulting Economists Limited, 2002). On September 22, the Governments of Canada and British Columbia agreed on a funding formula designed to assist in the construction of a 511- kilometer

Vancouver Island natural gas pipeline to make gas available to over 20 communities on Vancouver Island and the Sunshine Coast on the mainland. This project planned to serve about 100,000 people.

The $485-million project covering the transmission pipeline, local distribution facilities, and conversions was to have a private sector investment of $255 million. The federal government was to contribute $100 million towards the capital cost and a $50 million interest-free loan. The B.C. government was to provide $55 million to assist in energy conversions and an interest free loan of $25 million and, in addition, a $70 million repayable rate stabilization facility designed to backstop project work in the early years. The private sector sponsor of the project was Pacific Coast Energy Corporation. Following the agreement, engineering and environmental studies and public hearings were to be implemented. Following the negotiation of a final agreement in November, construction commenced on the natural gas pipeline to Vancouver Island.

The gas pipeline project was expected to generate a variety of economic benefits. These included:

- Increased ability of B.C.-based companies to produce products using natural gas as a fuel or feedstock,
- Increased employment from gas production in northeastern British Columbia based on 10% increase in natural gas sales,
- Royalties to the province of about $95 million over 20 years,
- Property taxes to municipalities from both the transmission line ($1.5 million per year) and distribution systems ($30 million over ten years),
- Plus the associated employment (construction, installation and maintenance).



Southwestern Manitoba – Canada-Manitoba Infrastructure Program (CMIP)

The Greenfield site lies in southwestern Manitoba, between Brandon and the United States border. The project to bring natural gas service to the Southwestern Manitoba was initiated by the governments of Manitoba and Canada through the announcement of funding through the Canada-Manitoba Infra-Structure program in 1994. The distribution project was designed to bring natural gas primarily to six towns in late 1995. These towns had a total population (1991) of about 8,100 people. Gas would also be available to residents and businesses located outside the towns in the surrounding rural municipalities that had a population of about 4,500 people. Customer sign-ups were sought by a volunteer community organization. Gas customers were required to contribute $300 to the funding partnership as a contribution to the infrastructure financing. The communities achieved an acceptable level of sign-up by January 1995. Centra Gas completed the distribution system in 1996, so 1997 was its first full year of operation.

The pipeline runs south from Brandon connecting the communities of Souris, Hartney, Melita, Boissevain, Deloraine and Killarney, and the rural municipalities in which they are located. The pipeline passes through two rural municipalities – Cornwallis and Whitewater – which do not receive gas service. These two areas chose not to join the group of communities participating in the financing package arranged to cover the capital costs of the line. One of the terms of that agreement was that non-participating communities would not be permitted access to gas service, a feature that still remains in force.

The area economy is grain based with the towns acting as service centers to surrounding farming areas providing retail service, health care and educational facilities. Tourism is also a significant factor for some communities. There are no large industrial operations in the area served by the gas project. Small manufacturing operations, schools, motels, arenas, a hospital and retirement homes were among the largest potential commercial customers for gas. Grain drying is an important activity that was traditionally based on propane fueled dryers. Natural gas was seen as a good alternative for its ease of conversion and to avoid fluctuations in propane prices that coincided with harvest season. Since the demise of the grain transportation subsidy in 1996, Crow Rate, diversification of the agri-food economic base has been an important priority in Manitoba. One result has been a rapid expansion of hog farming in the southwest area as well as other parts of the province.

The major benefits to the towns and the rural municipalities cited in materials circulated when the project was under consideration include:

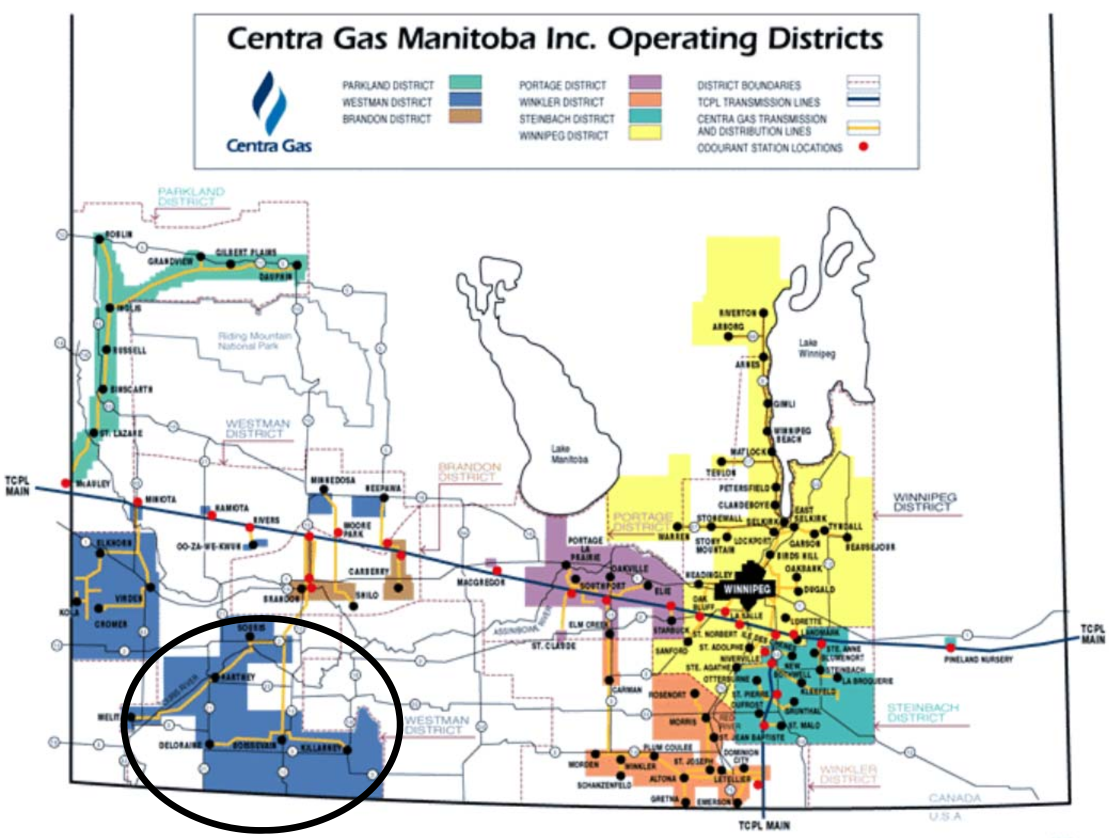
- Savings on energy costs to publicly funded buildings. e.g., schools, hospitals, rinks, pools, etc.
- Opportunities to build or attract industries that require this type of energy source. e.g., ethanol plants, straw processing, hog operations, pasta plants.
- Savings to existing businesses, allowing increased competitiveness and assisting in long term viability of town/service centers.
- Increased assessment in every municipal jurisdiction, creating an assured increase in future tax revenue.

- Increased tax revenue in all municipal jurisdictions resulting from increased assessments.
- Immediate increase in revenue through taxation of any branch lines constructed that are not included in the financing plan.

The total system cost was about $21.5 million financed by:

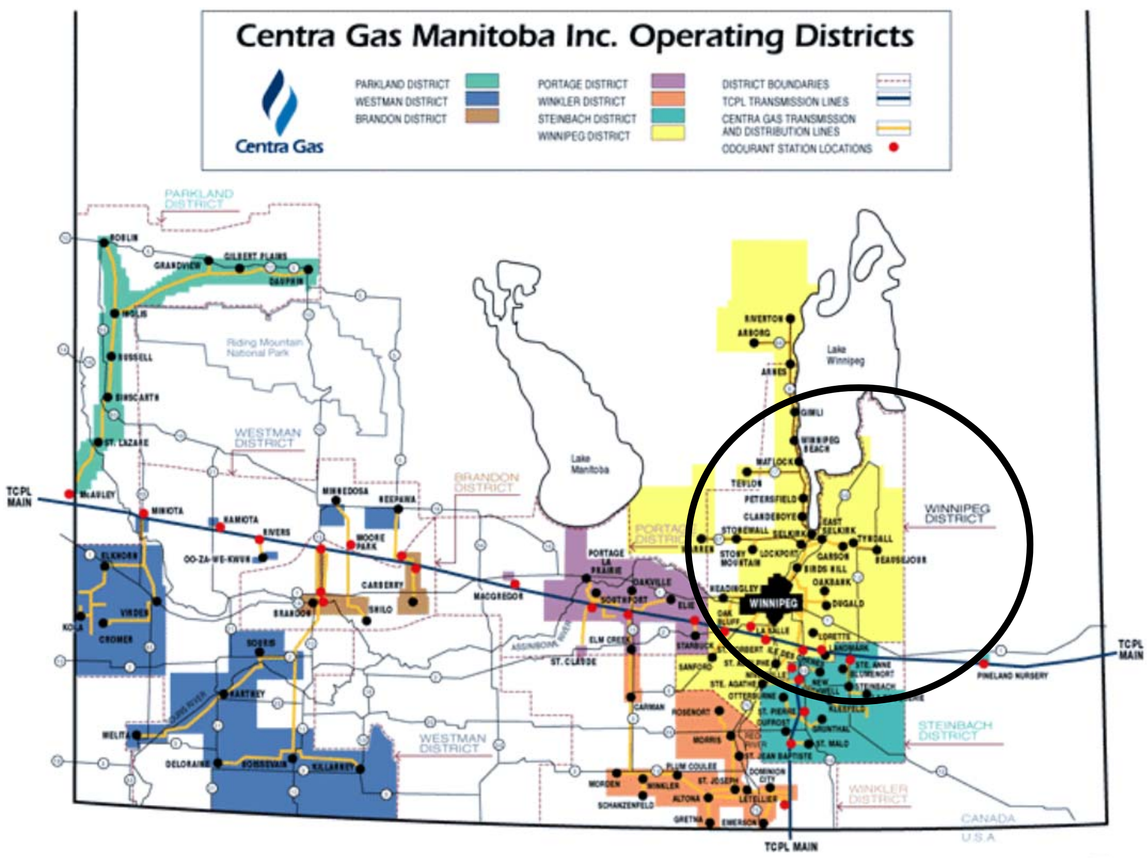
- Province $5.7 million
- Canada $5.7 million
- Municipalities $5.7 million
- Centra $3.7 million
- Customers $0.5 million

Manitoba and Canada contributed through the federal provincial Infra-structure Works program. The Municipalities issued debentures. Customers paid $300 each to participate.



Interlake Region, Manitoba – Canada Agri-Infrastructure Program (CAIP)

The Interlake Region north of Winnipeg received natural gas in 2000. This region lies between Lake Winnipeg and Lake Manitoba. Teulon, a town of about 1000 people lies at the centre of the region. The Interlake system was installed only because of the government assistance for capital costs. In the view of local observers, it would not have happened otherwise. The federal government introduced a post Crow rate infrastructure assistance program through which the area got $2.35 million in 1998 towards the $7.3 million system. Manitoba contributed a similar amount; municipalities contributed 15% or $1.1 million, financed by about 50% from incremental tax revenue from the distribution system and 50% from a new tax rate. This also included collecting some of the school taxes that are paid as part of property taxes. The arrival of natural gas will help these communities attract new businesses and many Interlake residents will now have the same home heating options enjoyed in other parts of the province. This is part of the commitment to upgrading vital infrastructure throughout Manitoba.



Parry Sound, Ontario

Parry Sound (population 6,300; 1996) is another area of central Ontario that has recently received natural gas. Delivery started in 2000. The Parry Sound economy is strongly tourism based (the Parry Sound region population jumps to 75,000 in the summer from the normal 15,000), and also includes a range of high-tech knowledge-based businesses and small-scale manufacturing/assembly. The area around Parry Sound, Ontario, was targeted for the distribution of natural gas in 1999 by Union Gas. The project was designed to install 98 km of pipelines to provide natural gas to approximately 1,800 residential and commercial customers in the first ten years of operation. The $16.5 million project was funded by Union Gas $9.7 million (59%), the

Town of Parry Sound and the Township of Seguin $800 thousand (5%), the Federal Government $3 million (18%) (through HRDC) and the Province of Ontario's Northern Ontario Heritage Fund $3 million (18%). Funding to expand the natural gas pipeline network into rural Ontario will make low-cost energy available to a greater number of Ontario citizens, including farms, and give them a better competitive advantage. In addition to home heating requirements, farm businesses use significant amounts of energy to heat barns, run grain dryers and ventilate buildings.

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PROFESSIONAL EXPERIENCE AND BACKGROUND OF

GARY S. SALEBA

EDUCATION

MBA, Finance
Butler University
Indianapolis, Indiana

BA, Economics and Mathematics
Franklin College
Franklin, Indiana

EMPLOYMENT

October 1978 to Present	EES Consulting, Inc. 570 Kirkland Way, Suite 100 Kirkland, Washington 98033 Registered Professional Engineering and Management Consulting Firm
Position:	President
Responsibilities:	Overall supervision and quality control responsibilities for all of EES Consulting's electric, water, wastewater and natural gas engagements in the areas of strategic planning, financial analysis, cost of service, extension policies, valuations, mergers and acquisitions, rate design, load forecasting, load research, management evaluation studies, bond financing, integrated resource planning and overall utility operations. Overall responsibility for firm's offices in Kirkland, and Portland.
Activities:	Numerous testimony presentations before regulatory bodies on utility economics, cost of service and rate design, strategic planning, finance and utility operations. Supervised several integrated resource planning studies, average embedded and marginal cost of service studies, technical assessments and financial planning studies for electric, water, gas and wastewater utility clients. Participated in comprehensive resource acquisition, strategic planning and demand side management analyses. Developed and verified interclass usage data. Conceptualized and implemented compliance programs for the Public Utility Regulatory Policies Act and the Energy Policy Act of 1992. Contract negotiation and energy conservation assessments. Presentation of management audit, forecasting, cost of service, integrated resource planning, financial management, and rate design seminars for the American Public

Power Association, Electricity Distributors Association of Ontario, American Water Works Association, and Northwest Public Power Association. Past Board member of Northwest Public Power Association and ENERconnect, Ltd. Past Chairman of Financial Management Committee and Management Division of the American Water Works Association. Project manager for construction of 248 MW gas turbine, and acquisition of over $500 million of utility service territory and equipment. Supervised engineer's report for over $5 billion in revenue bonds.

October 1977 to October 1978	National Management Consulting Firm
Position:	Supervising Economist
Responsibilities:	Analyzed various energy related topics to determine economic impacts. Reviewed utility financial activities.
Activities:	Participated in several utility rate/financial regulatory proceedings. Provided clients with critique of issues, position papers and expert testimony on the topics of cost of service, rate design, utility finance, automatic adjustment factors, sales perspectives and class load characteristics. Conceptualized load forecasting models and assisted in economic and environmental impact analyses.
June 1972 to October 1977	Indianapolis Power & Light Company P.O. Box 1595 B Indianapolis, Indiana 46206 Investor-owned Utility
Position:	Economist, Department of Rates and Regulatory Affairs
Responsibilities:	Provided general economic and rate expertise in Rates, Regulatory Affairs, Customer Service and Engineering Design Departments.
Activities:	Calculated retail and wholesale electric and steam class revenue requirements and rates. Prepared expert testimony and exhibits for state and federal agencies regarding rate design theory, application of rates and revenues generated from rates. Determined long range revenue and peak demand projections. Supervised comprehensive load research program. Supported thermal plant Environmental Impact Statements. Provided industrial liaison.

PARTIAL LIST OF CLIENTS FOR WHOM FINANCIAL, OPERATIONAL, STRATEGIC PLANNING AND ALLOCATIONAL/RATE ANALYSES PROJECTS HAVE BEEN PERFORMED BY GARY S. SALEBA

UNITED STATES OF AMERICA

Alabama

City of Birmingham Water and Wastewater

Alaska

City of Barrow
City of Wrangell
*Alaska Public Service Commission
*Municipal Light and Power
Alaska Village Electric Cooperative

Arizona

*Tucson Electric Power
City of Dodge
City of Page
Navopache Electric Cooperative

Arkansas

City of North Little Rock

California

City of Indian Wells
City of Palm Desert
City of Moreno Valley
*City of Corona
City of Redding
*Sacramento Municipal Utilities Board
City of Burbank
*State of California - Department of Water Resources
*Turlock Irrigation District
*City of Palo Alto
City of Anaheim
El Dorado Irrigation District
City of Glendale
*City of Pasadena
City of Roseville
Yucaipa Valley Water District
*Los Angeles Department of Water and Power
Nor–Cal Electric Authority

California (cont'd)

Jefferson JPA
City of San Marcos
City of Cerritos
Coachella Valley Association of Governments
California Power Authority
Santa Clara Valley Water District

Colorado

*CFI Steel
*Moon Lake Electric Association
City of Denver - Wastewater
*Denver Water Board

Connecticut

City of Groton

Florida

City of Pompano Beach
Florida Public Service Commission
Dade County Water and Wastewater Utilities

Idaho

Kootenai Electric
*Northern Lights
Salmon River Cooperative
Prairie Power and Light
*Department of Energy
City of Moscow
Fall River Cooperative
Lower Valley Power & Light
*Industrial Customers of Idaho Power
Clearwater Power & Light
City of Heyburn

Illinois

*City of Highland
City of Collinsville
City of Peru
City of Winnetka

Indiana

*Indianapolis Power & Light Company

Iowa

*City of Iowa City

Kentucky

*Kentucky-American Water Company

Minnesota

Polk-Burnett Electric Coop

Missouri

*General Motor, Inc.

Montana

*Beartooth Electric Cooperative
*PPL Montana
Montana Associated Cooperatives
Sun River Electric Cooperative
*Montana Power Company
Colstrip Community Center
+Flathead Electric Cooperative
Glacier Electric Cooperative
Vigilante Electric Cooperative
Montana Electric Cooperative Association
Western Montana G&T
*Northwestern Energy, Inc.
Yellowstone Valley Electric Cooperative

North Dakota

City of Watford City
Garrison Diversion Conservancy District

Oregon

*Emerald PUD
Clackamas Water District
Central Lincoln PUD
*Springfield Utility Board
Tri-Cities Service District
City of Portland
City of Gladstone
City of West Linn
City of Oregon City
*Public Power Council
Central Electric Cooperative
Warm Springs Energy Cooperative

Oregon (cont'd)

Northern Wasco PUD
West Oregon Cooperative

South Dakota

Black Hills Electric Cooperative

Texas

City of League City
City of Brownsville
*City of Lubbock
Pedernales Electric Cooperative
City of San Antonio
*Texas Municipal Power Agency

Utah

*Moon Lake Electric Association
Utah Association of Municipal Power Systems

Washington

*Western Public Agencies Group
+TrendWest Resorts
Weyerhaeuser Corporation
Costco
*Pend Oreille County PUD
City of Richland
Industrial Customers of Grant County
*Benton REA
Seattle City Light
+*Clark Public Utilities
City of Blaine
*Snohomish County PUD
*City of Port Angeles
+*Clallam County PUD
+Chelan County PUD
+*City of Tacoma Electric, Water and Rail Utilities
+*Mason County PUD No. 3
+*Peninsula Light Company
Washington Utilities and Transportation Commission
+*Grays Harbor County PUD
*Pacific County PUD
City of Gig Harbor
Ferry County PUD
+*City of Ellensburg
City of Redmond
Grant County PUD
*Klickitat County PUD

Washington (cont'd)

Cascade Natural Gas
*Building Owner's Management Association
City of Kennewick
Daishowa Corporation
Seattle Water Department
*Building Management Owners Association
City of Bellingham
*US Ecology, Inc.
*Avista Corporation
*Cowlitz County PUD
*City of Cheney
*City of Yakima
City of Bellevue
+City of Shoreline
*Douglas County PUD
AT&T
WorldCom
City of Toppenish
+Jefferson PUD
+ Lewis PUD

Wisconsin

*Wisconsin Manufacturing Association
Polk-Burnett Cooperative

Wyoming

*Lower Valley Power and Light

CANADA

Alberta

*University of Alberta
*City of Lethbridge
*City of Red Deer
City of Medicine Hat
Ocelot Chemicals
Aqualta
City of Calgary—Water and Wastewater Utilities

British Columbia

+*Fortis, BC
Alcan, Ltd.
*Princeton Power & Light
*West Kootenay Power
*Ministry of Fisheries
Crows Nest Resources

British Columbia (cont'd)

Highland Valley Cooperative
*Council of Forest Industries
Crestbrook Industries
Royal Oak Mines
UtiliCorp Canada
*Joint Industrial Electric Steering Committee
*British Columbia Transmission Corporation
+*Terasen Gas

Manitoba

*Manitoba Legal Aid

Northwest Territories

*Northwest Territories Power Corporation

Ontario

ENERconnect, Inc.
Ontario Hydro
*Municipal Electric Association
North York Hydro
Toronto Hydro
*Ottawa Hydro
Electricity Distributors Association
Ontario Energy Board
*Association of Major Power Companies (AMPCO)

OTHERS

American Public Power Association
American Water Works Association
California Municipal Utilities Association
Northwest Public Power Association

*Prepared Expert Testimony
+ Projects involving extension policies

PROFESSIONAL EXPERIENCE AND BACKGROUND OF

GAIL D. TABONE

EDUCATION

M.S., Agricultural and Applied Economics
University of Minnesota
St. Paul, MN (1984)

B.S., Economics
University of Minnesota
Minneapolis, MN (1982)

EMPLOYMENT

August 1988 to Present	EES Consulting 570 Kirkland Way, Suite 100 Kirkland, Washington 98033 Registered Professional Engineering and Management Consulting Firm
Position:	Senior Associate
Responsibilities:	Management of projects including cost of service studies, rate designs, extension policies, load forecasting, load research, least cost planning and financial analyses. Provide expert testimony on cost of service and rate design, least cost planning and load forecasting.
Activities:	Design and implement computer based cost of service models for electric, natural gas and water/wastewater utilities. Prepare rate design for utilities using cost of service results and marginal cost pricing. Provide research, support and analysis related to regulatory filings. Prepare end-use and econometric load forecasts for electric utilities. Prepare statistical design for load research programs and analyze resulting load data. Conduct integrated resource plans and least cost planning for utilities, including research on generation technologies, demand-side management options,

cost estimation of alternatives, and economic evaluations. Evaluation of resource and power contract proposals and assistance with contract negotiations. Conduct analysis related to mergers and acquisitions of utilities, including pro forma financial analysis, power supply alternatives and operating strategies.

January 1986 to June 1988	United Power Association Elk River, MN Generation and Transmission Cooperative
Position:	Power Requirements Analyst
Responsibilities:	Preparation of end-use forecast for 15 member cooperatives.
Activities:	Design end-use forecasting model and prepare forecasts of specific end-uses of electricity. Conduct load pattern analysis and weather normalization. Analyze data on load management programs.

PARTIAL LIST OF CLIENTS FOR WHOM FINANCIAL, OPERATIONAL, STRATEGIC PLANNING AND ALLOCATIONAL/RATE ANALYSES PROJECTS HAVE BEEN PERFORMED BY GAIL D. TABONE

UNITED STATES OF AMERICA

Alaska

*Municipal Light and Power

Arizona

*Tucson Electric Power

California

*Northern California Generation Coalition
*Turlock Irrigation District
City of Anaheim
*Los Angeles Department of Water and Power
Nor–Cal Electric Authority
City of San Marcos
City of Cerritos
Coachella Valley Association of Governments

Florida

Dade County Water and Wastewater Utilities

Idaho

Idaho Falls Power
Kootenai Electric
*Northern Lights
Fall River Cooperative
Lower Valley Power & Light
*Industrial Customers of Idaho Power

Illinois

City of Winnetka

Minnesota

Polk-Burnett Electric Coop

Montana

*Beartooth Electric Cooperative
Montana Associated Cooperatives
+Flathead Electric Cooperative
Vigilante Electric Cooperative
Montana Electric Cooperative Association
*Northwestern Energy, Inc.

Oregon

*Emerald PUD
*Springfield Utility Board
Northern Wasco PUD

Texas

*Texas Municipal Power Agency

Utah

Utah Association of Municipal Power Systems

Washington

*Western Public Agencies Group
+TrendWest Resorts
Weyerhaeuser Corporation
Costco
*Pend Oreille County PUD
City of Richland
Industrial Customers of Grant County
*Benton REA
Seattle City Light
+*Clark Public Utilities
*Snohomish County PUD
+*Clallam County PUD
+Chelan County PUD
+*City of Tacoma Electric, Water and Rail Utilities
+*Mason County PUD No. 3
+*Peninsula Light Company
+*Grays Harbor County PUD
*Pacific County PUD
+*City of Ellensburg
Grant County PUD
*Klickitat County PUD
*Building Owner's Management Association
Seattle Water Department

*Building Management Owners Association
*Avista Corporation
+City of Shoreline
*Douglas County PUD
AT&T
WorldCom
City of Toppenish
+Jefferson PUD

Wyoming

*Lower Valley Power and Light

CANADA

Alberta

*University of Alberta
*City of Lethbridge
*City of Red Deer
City of Medicine Hat
City of Calgary—Water and Wastewater Utilities

British Columbia

+*Fortis, BC
*West Kootenay Power
*Council of Forest Industries
Royal Oak Mines
UtiliCorp Canada
*Joint Industrial Electric Steering Committee
+*Terasen Gas

Northwest Territories

*Northwest Territories Power Corporation

Ontario

ENERconnect, Inc.
*Municipal Electric Association

*Prepared Expert Testimony
+ Projects including line extension issues

Appendix B

WORKSHOP MATERIALS

System Extension Stakeholder Workshop

Event Details:

Date:	Tuesday February 18th, 2014
Time:	7:30 AM – 3:00 PM
Location:	Connaught Room – The Metropolitan Hotel 645 Howe Street Vancouver, BC V6C 2Y9 604-687-1122 http://www.metropolitan.com/vanc

Contact: Mike Metza
Energy Products & Services Manager
Tel: 604-592-7852
Cell: 604-790-5334
Fax: 604-592-7620
mike.metza@fortisbc.com

Agenda:

Time	Topic	Details	Presenter
7:30 – 8:30		***Registration - Breakfast Provided***	
8:30 – 9:15	Introduction	• Introductions & Meeting Objectives • How We Serve Our Customers	*Jason Wolfe – Fortis BC*
9:15 – 10:30	Customer Needs	• Off System Communities • Builder/Developer	*George Bush – Okanagan - Similkameen Regional Dist.* *Karen Goodings – Peace River Regional Dist.* *TBD.*
10:30 – 10:45		***Break***	
10:45 – 12:00	Customer Needs	• Development Example • New Homeowners/Renters	*Mike Metza – Fortis BC*
12:00 – 1:00		***Lunch Provided***	
1:00 – 2:30	EES Consulting Utility Comparisons	• Utility Comparison	*Gail Tabone – EES Consulting*
2:30 – 3:00	Closing	• Key Messages • Next Steps	*Jason Wolfe – Fortis BC*

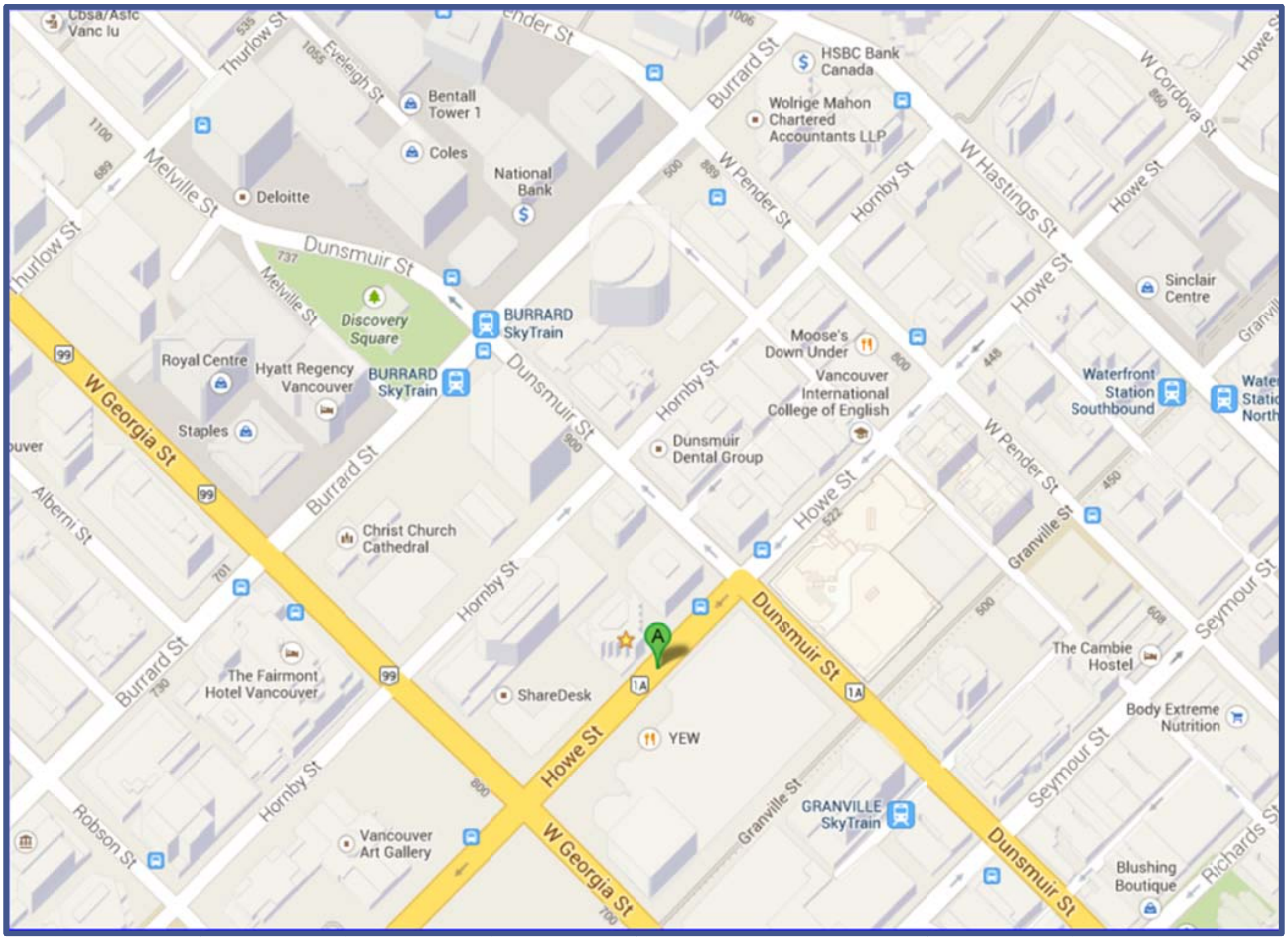
Special Notes:

- Parking is available at the Metropolitan Hotel - The entrance to the underground parking is just past the entrance of the Metropolitan Hotel – 645 Howe Street.
- When you are registering in the morning please inform us if you have parked at the Metropolitan and we will give you a free parking or discount parking voucher to attach to your ticket.
- Coffee and beverages will be provided throughout the day.

List of Confirmed Attendees:

Name	Title	Stakeholder
Justin Miedema	Senior Regulatory Advisor, Rates and Regulatory	BC Hydro
Kevin Lim-Kong	Policy Specialist, Customer Interconnections & Policy	BC Hydro
Frank Lin	Director, Interconnections and Shared Assets	BC Hydro
Rena Messerschmidt	Policy Manager, Customers Interconnections & Policy	BC Hydro
Katherine Muncaster	Acting Director, Energy Efficiency Branch	BC Ministry of Energy and Mines
Nathaniel Gosman	Senior Policy Advisor	BC Ministry of Energy and Mines
Kristine Bienert	Acting Director, Policy, Planning and Customer Relations	BC Utilities Commission
Suzanne Sue	Senior Regulatory Specialist	BC Utilities Commission
J. Todd Smith	Acting Director, Infrastructure	BC Utilities Commission
Chris Garand	Engineer, Infrastructure	BC Utilities Commission
David Craig	President, Consolidated Management Consultants	Commercial Energy Consumers BC
Gail Tabone	Senior Consultant, EES Consulting	EES Consulting Ltd.
Mike Metza	Energy Products & Services Manager	Fortis BC
Brent Graham	Manager, Energy Products & Services	Fortis BC
Jason Wolfe	Director, Market Development	Fortis BC
Dennis Swanson	Director, Regulatory Affairs	Fortis BC
Howard Mak	Customer Programs Manager	Fortis BC
Colleen Misner	Constituency Assistant to Linda Larson, MLA	MLA, Boundary-Similkameen
George Bush	Board Member	Okanagan - Similkameen Regional District
Janet Kennedy	Vice President, Regulatory Affairs and Gas Supply	Pacific Northern Gas
Peter Schriber	Manager, Financial Planning & Business Development	Pacific Northern Gas
Karen Goodings	Board Director	Peace River Regional District
Tannis Braithwaite	Executive Director	Public Interest Advocacy Centre

Maps:



Parking

FortisBC System Extension Stakeholder Workshop

Introductions:

PRRD

REGIONAL DISTRICT
RDOS
OKANAGAN-SIMILKAMEEN

CEC
British Columbia

BC PIAC
British Columbia Public Interest Advocacy Centre

British Columbia Utilities Commission

BRITISH COLUMBIA

MLA Linda Larson
Boundary-Similkameen

FORTIS BC™

BChydro

EES Consulting

PNG Pacific Northern Gas Ltd.

Workshop Objectives:

- Background on Existing System Extension Framework
- Understanding Customer Needs

FortisBC Objectives:

- Make it Easier for Customers to Attach to our System
- Encourage the Efficient Use of Natural Gas

How We Serve Our Customers

Our System Extension Customers

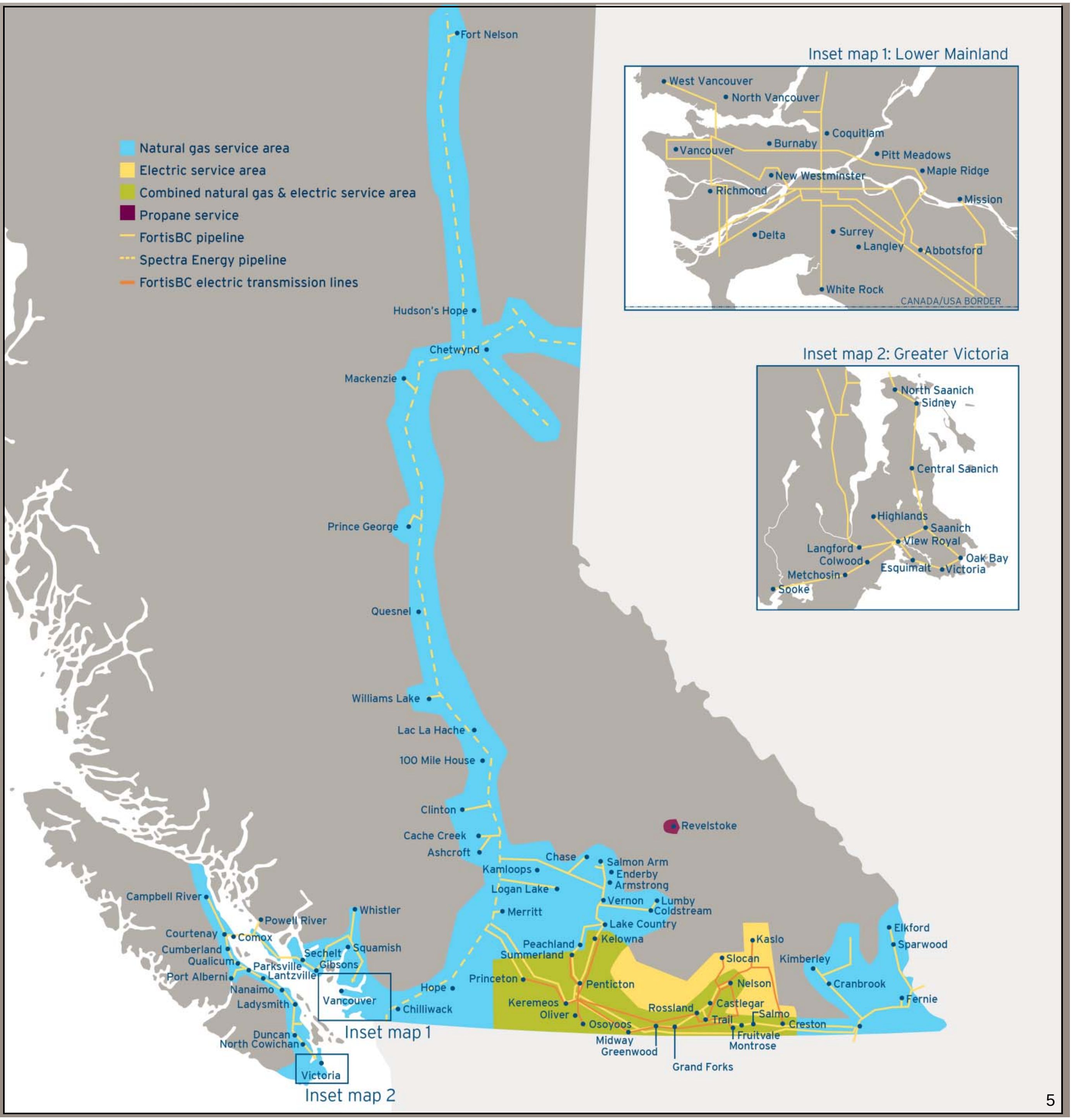
Builder/ Developer

New Homeowners/ Renters

Off-System Communities

How We Serve Our Customers

FortisBC Service Area Map



How We Serve Our Customers

Attaching New Customers

Revenue ÷ Cost = Economic Test

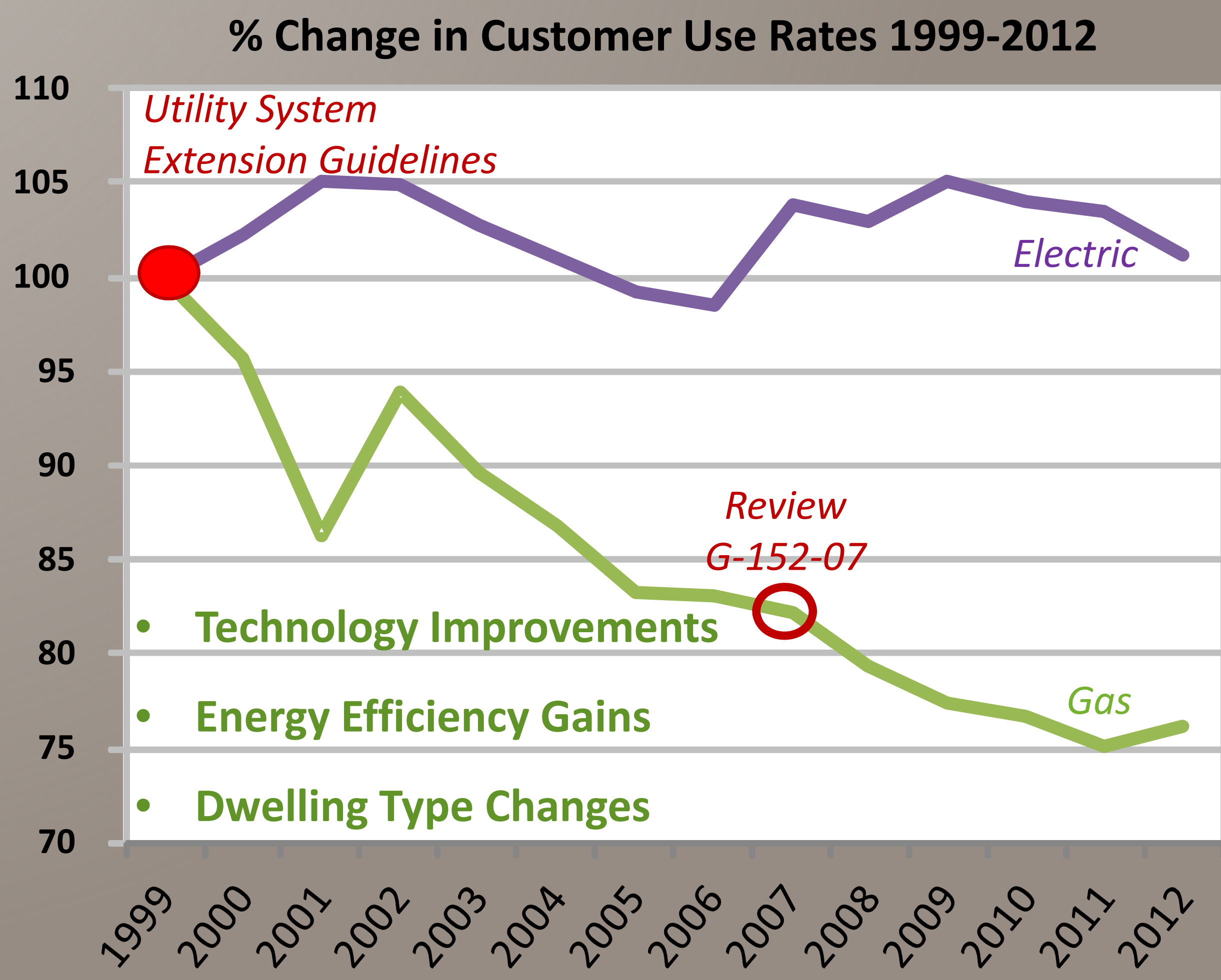
- Market
- Usage
- Rates
- Time

- Planning
- Construction
- Overhead

- Output = P.I.

How We Serve Our Customers

System Extension History in BC



*Source 2012 REUS

Customer Needs

Customer Needs

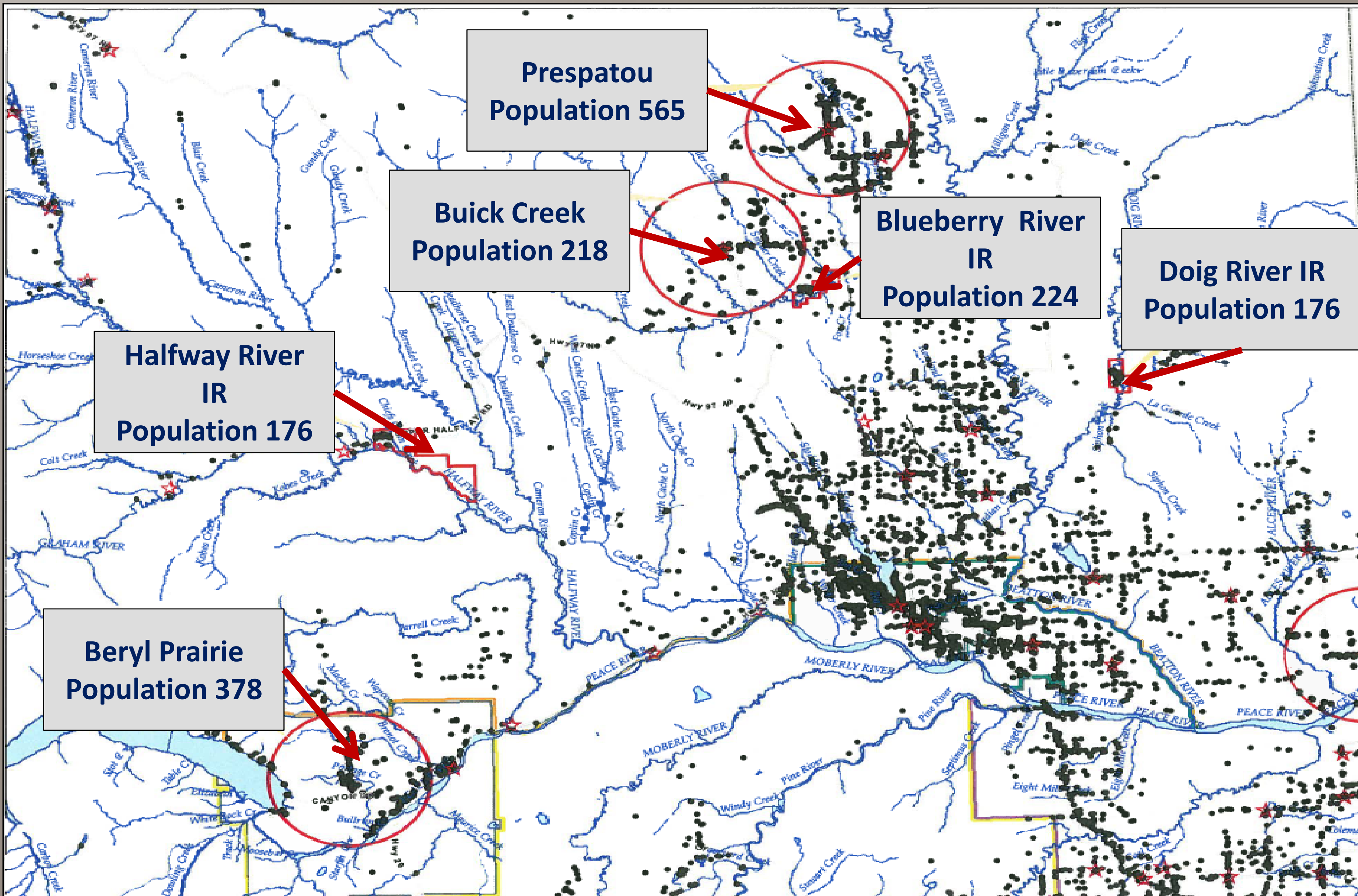
Off-System Communities

- Feedback from constituents…

  "provide us with a choice"

Customer Needs

Off-System Communities



Customer Needs

Off-System Communities

- No energy choice, Propane is the only option in many cases
- Commercial and Residential constituents at the mercy of the market

Market Propane	**FortisBC Natural Gas**
$35.10 / GJ	**$8.50 /GJ**
Clayhurst	***Inland Areas***

Customer Needs

Off-System Communities

- Local government is trying but needs assistance

- Up to $5,000 grant available for gas expansion

- Helps, but often not enough

Customer Needs

Off-System Communities

- Feedback from constituents…

  "provide us with a choice"

Customer Needs

Off-System Communities

Trail

I recently sent you a copy of a letter I wrote to the BCUC regarding the new residential two tier conservation rates. I am not the only one to find these new rates discriminatory and punitive to those of us who have no choice whether or not to use electricity for home heating. I find the fact that my equal

Naramata

regularly services our installation.

We do not have natural gas and thus cannot change over to a cheaper system.

Kelowna

Is this new rate structure designed to encourage electrical users to switch from electric heat to oil? (Natural Gas is not available in my area.) If so, I would appreciate so public discussion of the policy.

Coalmont

habits, our rate has skyrocketed from $303.00 to $454.00!!! We live in a community that doesn't have gas, so our heat is from electric baseboard heaters. Your 800 kwh monthly cutoff point for the lower electricity rate SERIOUSLY PENALIZES those who MUST use electricity for their heat, and is UNFAIR to all those who live in rural areas that have no choice but to use electricity for heat. This one aspect of your rate structure SHOULD BE

Customer Needs

Off-System Communities - Kingsgate, B.C. Area

Complaint to British Columbia Utility Commission:

I live in south eastern BC, very near the Idaho border and also very near the main natural gas pipeline that feeds US markets as far away as Chicago (according to information provided me in recent phone calls to Fortis BC).

Along the pipeline corridor there are numerous rural communities south of Cranbrook BC all the way to the Idaho border, none of which have natural gas service. It should be a major responsibility of Fortis to develop the domestic market, with the natural resource that is sourced in this province, with priority over foreign markets, both on this continent, and overseas.

Simply put... if you are sourcing a natural resource in my province, then I and all residents of BC need to have easy, affordable use of that resource. The expectation of using huge quantities of gas to operate compressors for the production of LNG for export is an insult, and a form of corruption against BC residents without natural gas services. Domestic Market first, export second.

Customer Needs

Builder/Developer

Business Model

Revenue — Cost = Profit

Revenue
- # units **X** $/unit

Cost
- Land
- Consultants
- Permits
- Muni. Charges
- Marketing
- Management
- Site Development
- Construction Cost
- Interest
- Utilities

Profit
- Min. ROI to attract capital & bank financing

Customer Needs

Builder/Developer

Market Differentiation

Customer Needs

Builder/Developer/Community

Sustainable Design - Solo

- 1,300 Residences over 4 Phases
- Commercial Space
- Office Space

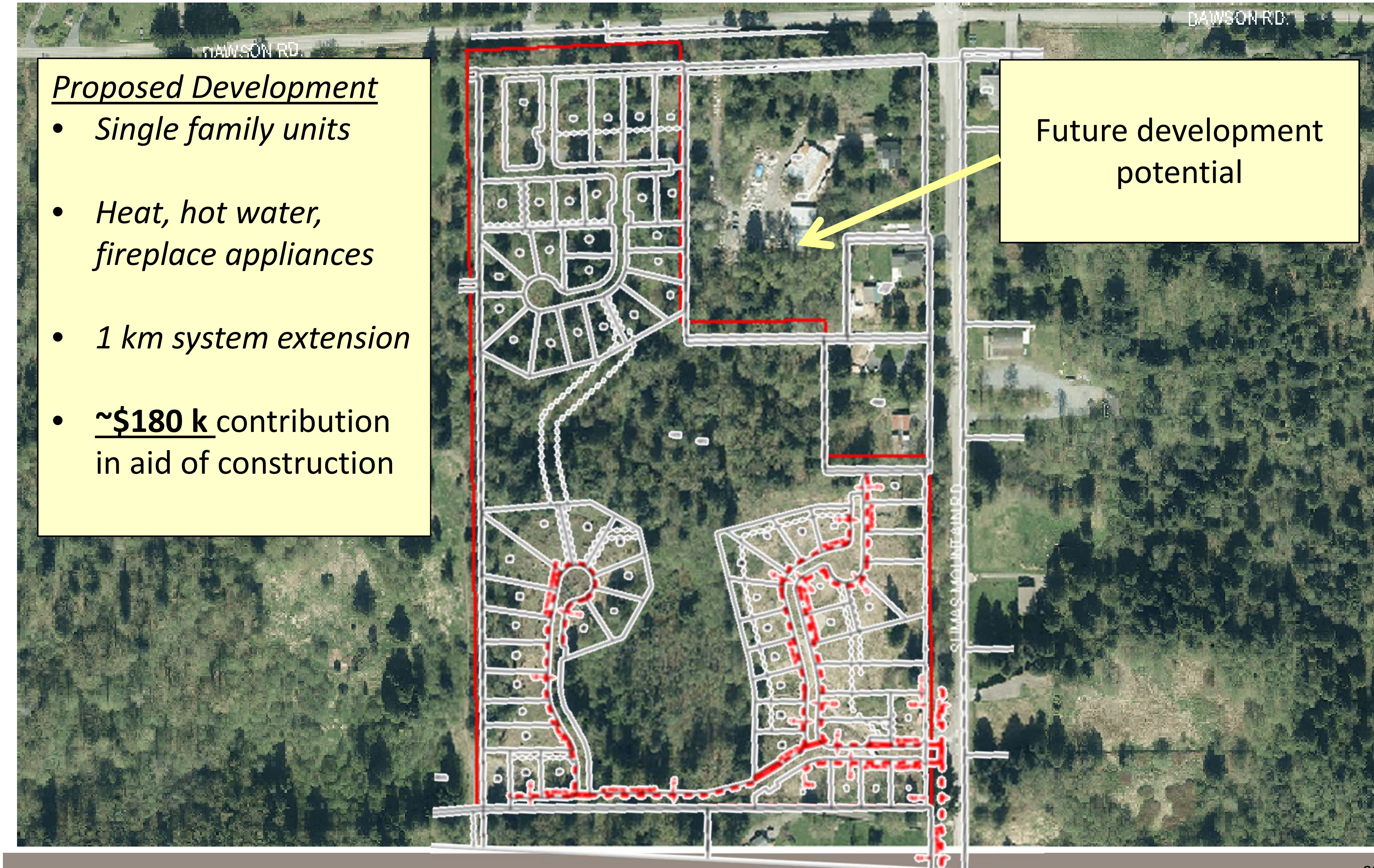
- Geo Thermal
- Waste Heat Recovery
- Gas Appliances

Customer Needs

Builder/Developer ***Reasonable Cost-Benefit***

Customer Needs

Builder/Developer **_Reasonable Cost-Benefit_**



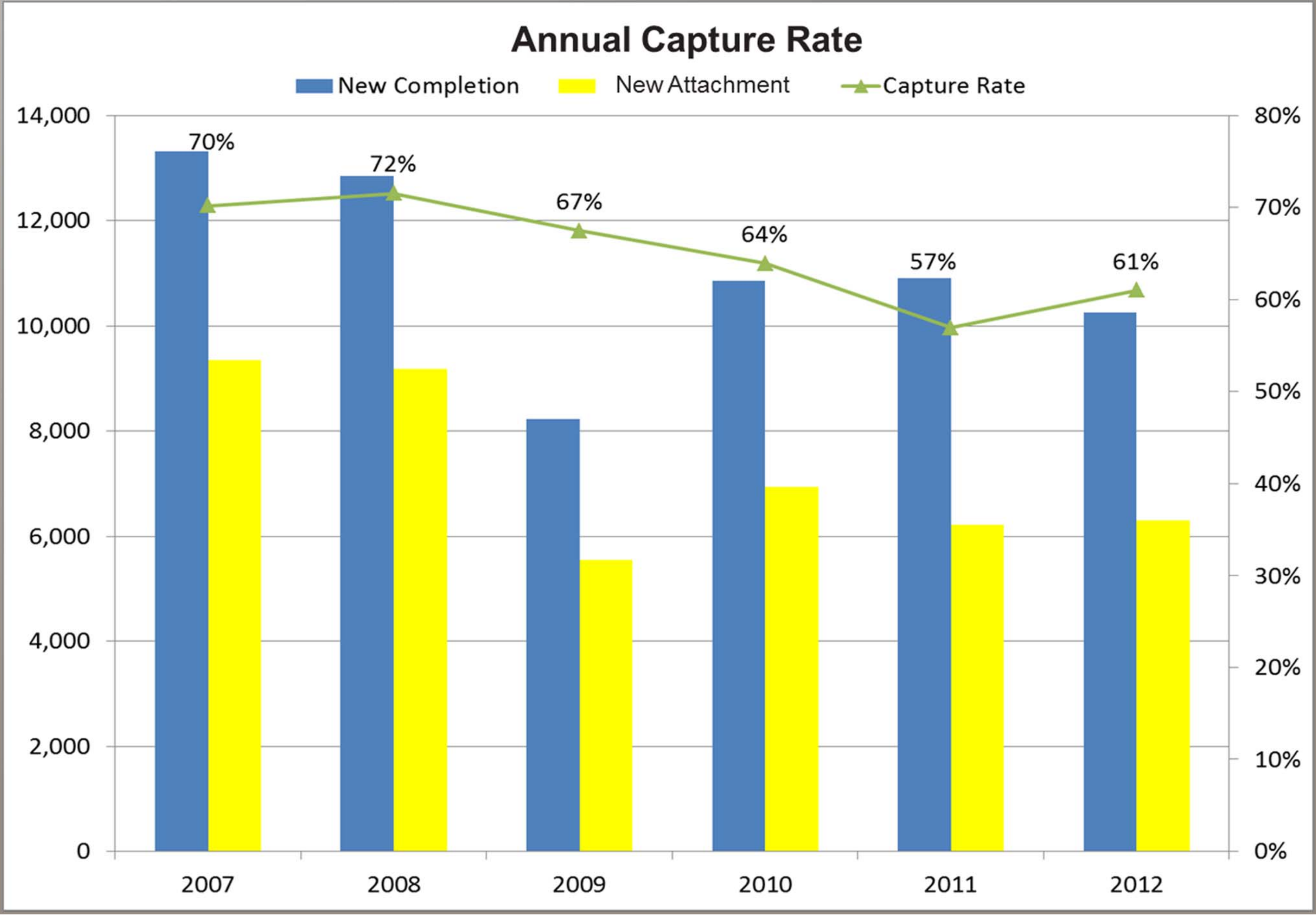
__Proposed Development__

- *Single family units*
- *Heat, hot water, fireplace appliances*
- *1 km system extension*
- **__~$180 k__** contribution in aid of construction

Future development potential

Customer Needs

Builder/Developer ***2012 – Provincial Results***



Customer Needs

Builder/Developers & System Extensions

Customer Needs

Builder/Developers & System Extensions

Customer Needs

Builder/Developers & System Extensions

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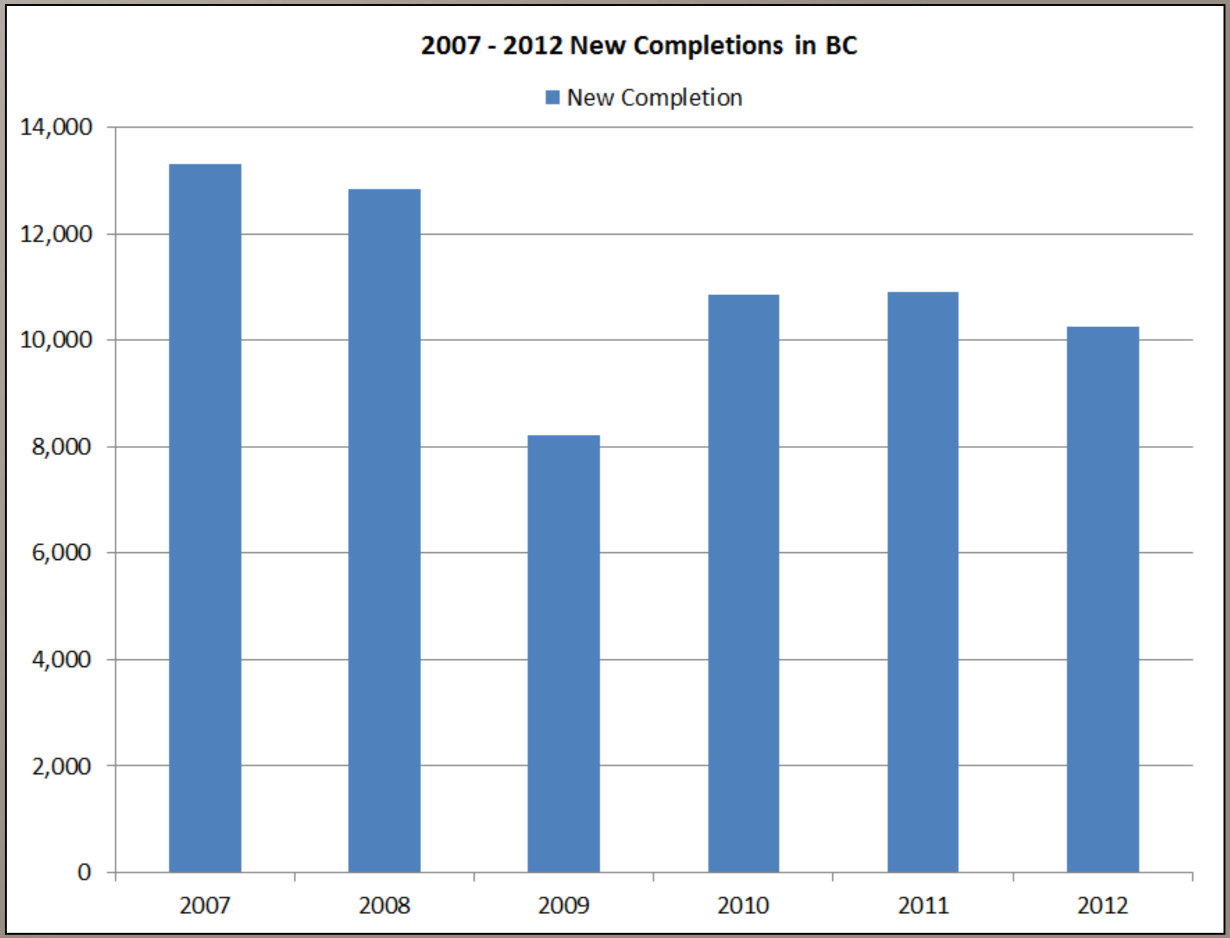
Customer Needs

Builder/Developers & System Extensions



**Source BC Assessment*

Customer Needs

New Homeowners / Renters: Cost

New natural gas furnace

Standard

AFUE: 90

Installed cost: 5000

Compare

Electric furnace

Type: Electric furnace (standard)

Installed cost: 1000

System 1

Annual electricity use:	**342 kWh**
Annual natural gas use:	**99 GJ**
Annual energy cost:	**$972**

System 2

Annual electricity use:	**25,011 kWh**
Annual energy cost:	**$2,726**

Estimated savings summary

System 1 is less expensive to operate. You could save an estimated **$1,754** annually.

it will take you **2.3 years** to recover the addtional installed costs required to install the more expensive system.

Customer Needs

New Homeowners / Renters: Cost

Customer Consideration: Operating Costs

↓

Different Needs

↑

Builder/Developer Consideration: ROI

Customer Needs

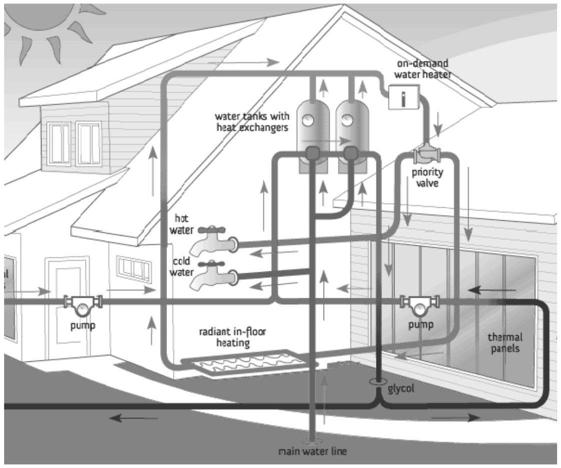
New Homeowners / Renters:

Usage Patterns

Appliances

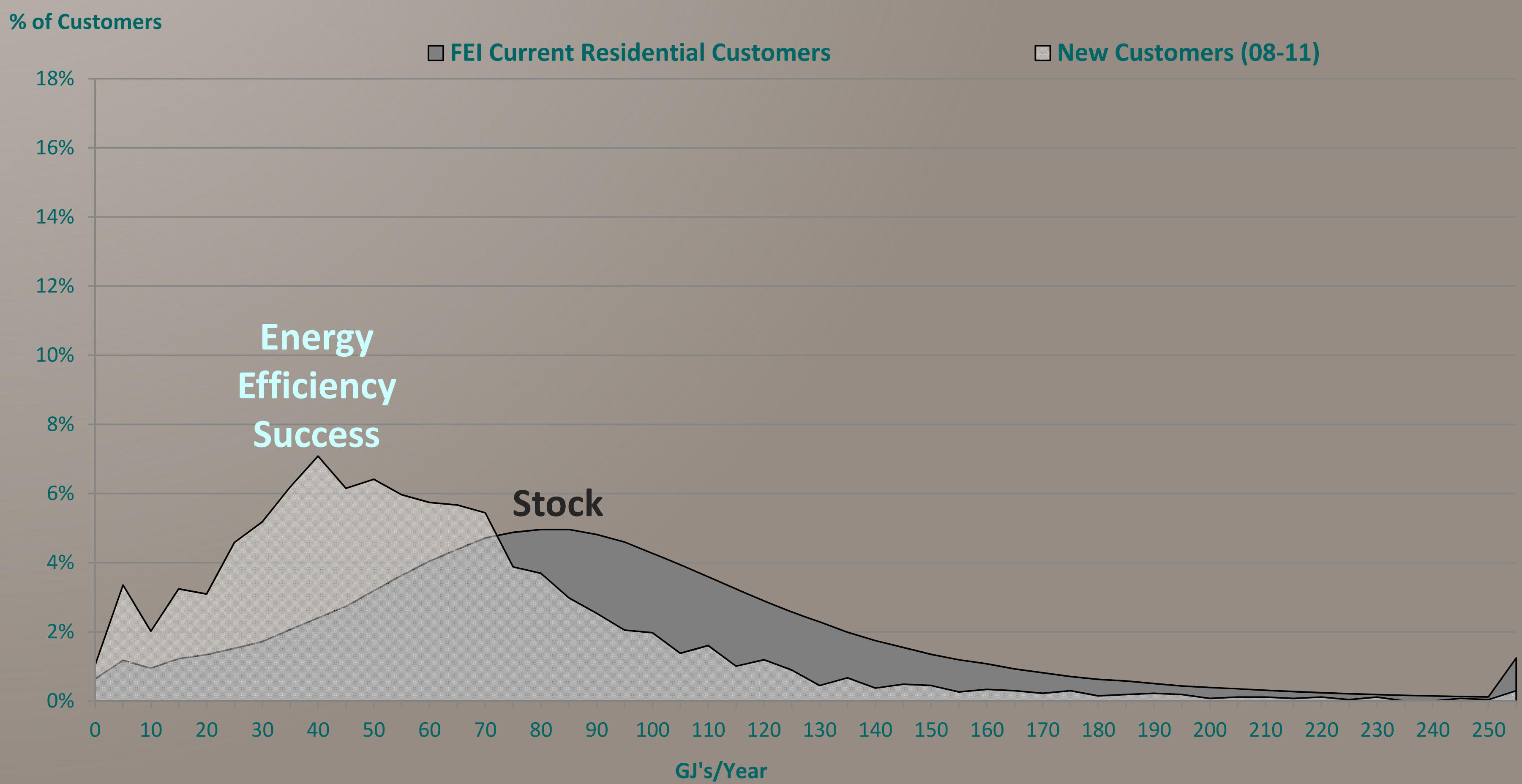
Behavior

Energy Efficiency Measures



Customer Needs

New Homeowners/Renters: Declining Use



Customer Needs

New Homeowners / Renters: Carbon Neutral

- Renewable Natural Gas
- Provide Customers with a Choice

EES Consulting
Utility Comparisons

Utility Comparisons

Background

- EES Consulting provided a report to FortisBC in March 2013
- Survey of system extension policies for Gas Utilities across Canada and West Coast U.S.
- Considered general approach as well as how allowances were calculated

Utility Comparisons

General Approaches

Method	Utilities
Cost-benefit approach	■ FEU - MX Test ■ Other Canadian, WA Gas Utilities
Standard credit per customer	■ BC Hydro ■ FortisBC - Electric
Standard distance allowed per customer	■ OH – Dominion Gas
Standard credit per appliance	■ OR - Northwest Natural ■ CA – PG&E, So Cal Gas, SDG&E

Utility Comparisons

Cost/Benefit Approach

Consideration	Other Utilities	FEU
Time	30 to 40 years	20 years
Costs	ATCO and Avista – 3 years and no costs	Costs + Overhead
Rates	Add Inflation	No Rate Inflation
P.I.	.75 to 1.0	1.1 on aggregate (.8 individually)

Utility Comparisons

Standard Credit per Customer

- FortisBC electric calculates amount in rate base for average customer ($1741 residential)
- BC Hydro has standard cost/benefit approach based on average customer usage and cost ($1475 residential)
- Based on cost of transformer, meter and service line

Utility Comparisons

Standard Credit per Appliance

- Use cost-benefit approach to develop standard credits per appliance
- CA utilities use an additive approach
- NW Natural uses total value based on highest use appliance

Utility	Space Heat	Water Heat	Oven/ Range	Dryer Stub
PG&E	$649	$529	$57	$22
So Cal Gas	$503	$441	$77	$107
SDG&E	$479	$554	$99	$140
NW Natural	$2875	$2100	$850	$850

Next Steps

Workshop Objectives:

- Background on Existing System Extension Framework
- Understanding Customer Needs

FortisBC Objectives:

- Make it Easier for Customers to Attach to our System
- Encourage the Efficient Use of Natural Gas

Fortis BC would like to thank everyone for their recent participation in the FortisBC System Extension Stakeholder Workshop which took place on February 18th. As part of the next step in the review process, you are being forwarded this invitation to secure a place holder for the next Stakeholder workshop. This second workshop will be structured around a group discussion approach to defining the scope, objectives and terms of reference to be used in full review of system extension policies. The feedback from the second workshop will form the basis for a third workshop, to be scheduled at a later date, where the Companies and Stakeholders will explore system extension options in greater detail.

The following invitation is a placeholder, with further details to follow at a later date.

Subject: FortisBC System Extension Stakeholder Workshop #2

Date: Wednesday June 18th, 2014

Time: 7:45 am – 12:00 pm

Location: Connaught Room - The Metropolitan Hotel Vancouver
645 Howe Street
Vancouver, BC V6C 2Y9
604-687-1122
http://www.metropolitan.com/vanc

Agenda:

7:45-8:30	**Breakfast Provided**	
8:30 – 10:00	**FortisBC & Group Discussion**	• **Workshop Objectives** • **Discuss Guiding Principles of Policy Formulation**
10:00 – 10:20	**Break**	
10:20 – 12:30	**Group Discussion**	• **Define Terms of Reference and Scope of New Policies** • **Next Steps**

Contact: Mike Metza
Energy Products & Services Manager, Fortis BC
Tel: 604-592-7852Cell: 604-790-5334
Fax: 604-592-7620
mike.metza@fortisbc.com

FortisBC System Extension Stakeholder Workshop #2

June 18, 2014

Introductions:

Yale First Nation Government

Chawathil First Nation

Seabird Island Band

Regional District RDOS Okanagan-Similkameen

BC PIAC British Columbia Public Interest Advocacy Centre

BC First Nations Energy and Mining Council

PRRD

British Columbia Utilities Commission

MLA Linda Larson Boundary-Similkameen

Ucluelet Chamber of Commerce

British Columbia

CEC British Columbia

Fraser Valley Regional District

FortisBC

EES Consulting

PNG Pacific Northern Gas Ltd.

BC hydro

Workshop Objectives:

- Summary of Workshop #1
- Review Terms of Reference
- Discuss Guiding Principles for MX Policy
- Confirm Deliverables

FortisBC Objectives:

- Make it Easier for Customers to Attach to our System
- Encourage the Efficient Use of Natural Gas

Workshop #1 Review

Terminology

Term	Definition
Main Extension Installation of natural gas distribution infrastructure to bring service to a designated area • Usually on public property • All main extensions are subject to the System Extension Test	
Service Line Installation of natural gas distribution infrastructure to bring natural gas from the gas main to a building • Usually on private property • All residential and small commercial service lines receive a standard credit	

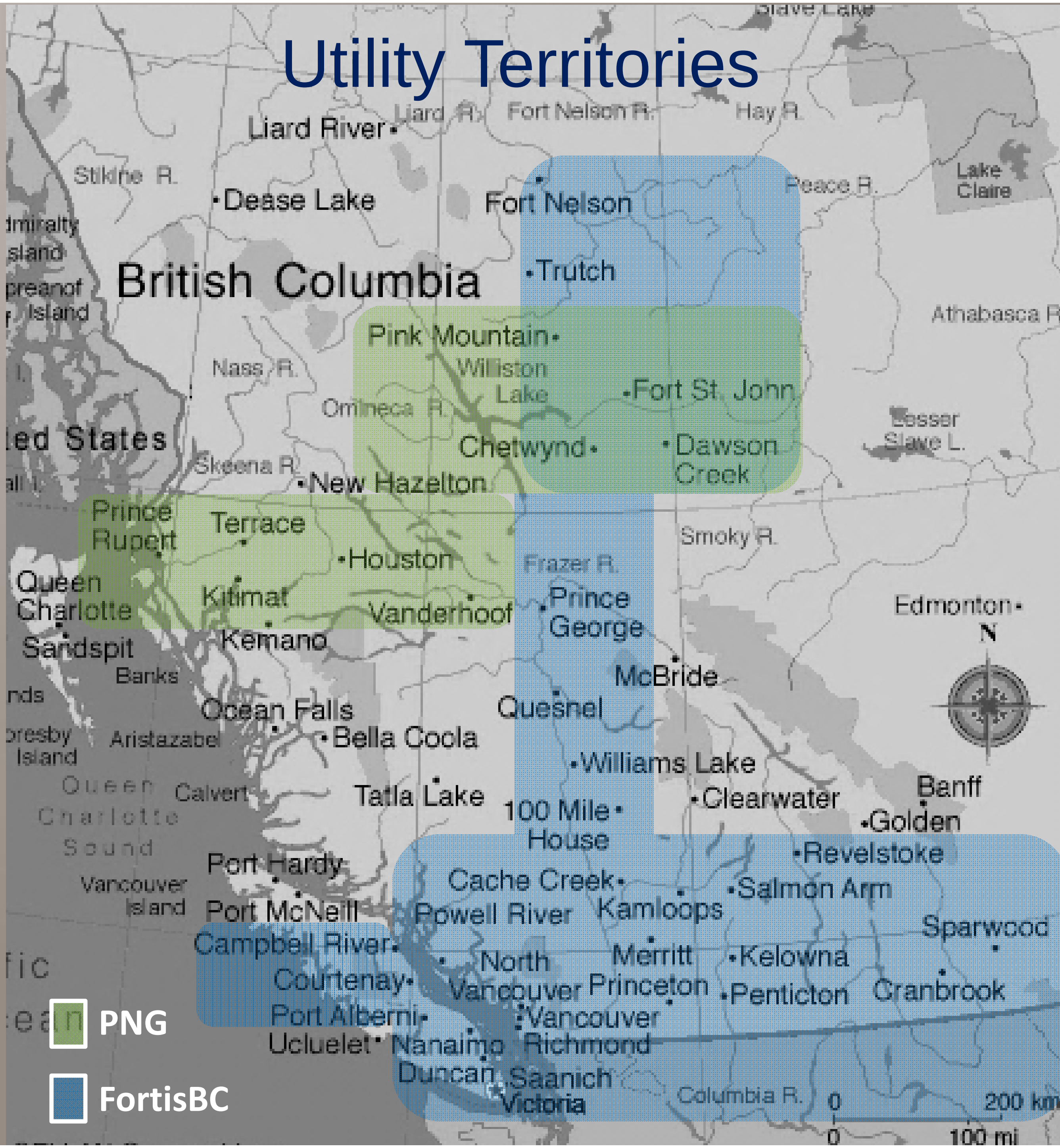
Terminology

Term	Definition
System Extension Test (Economic or MX Test) A forecasted calculation used to determine the economic viability of bringing natural gas to a new location • Potential number of customers • Expected gas usage • Estimated Cost	**Revenue** ÷ **Cost** = **Economic Test**
Service Line Cost Allowance (SLCA) The credit amount received by a customer who already has gas on their street and only needs a service line. This credit helps offset the cost of the installation • Determined by the test above	**$1535**

Terminology

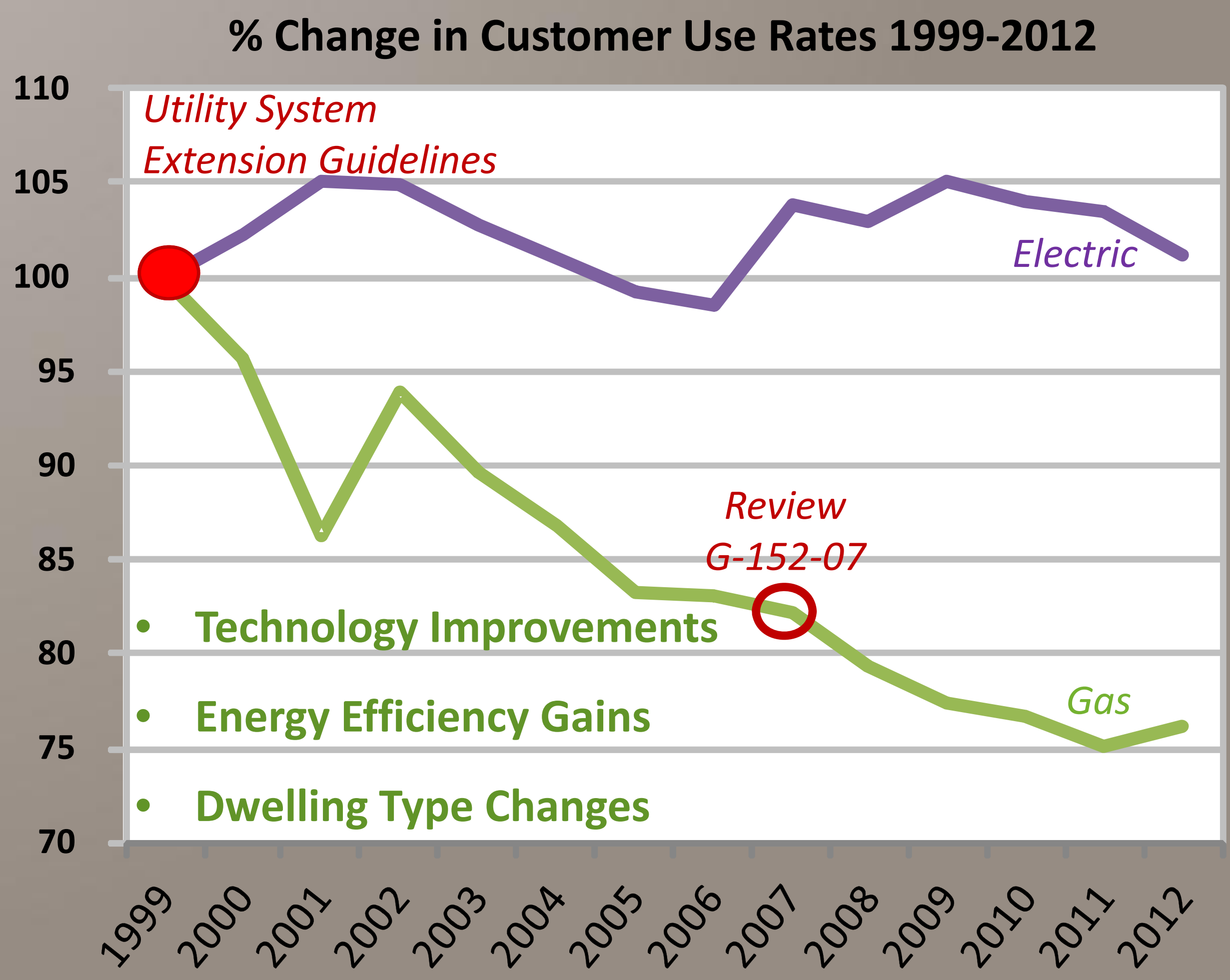
Term	Definition
Consumption, "Load"	The expected gas consumption for a customer. The load is based on many factors such as • Energy efficiency • Appliance type • Household size • Individual preference 
Contribution, "CIAC"	A contribution in aid of construction arises when the expected revenue from a customer is not enough to pass the "economic" threshold of system extension test $\underbrace{1000}_{\text{Expected Revenue}} \div \underbrace{2000}_{\text{Estimated Cost}} = 0.5$ *Customer must make a contribution*

Utility Territories



How We Serve Our Customers

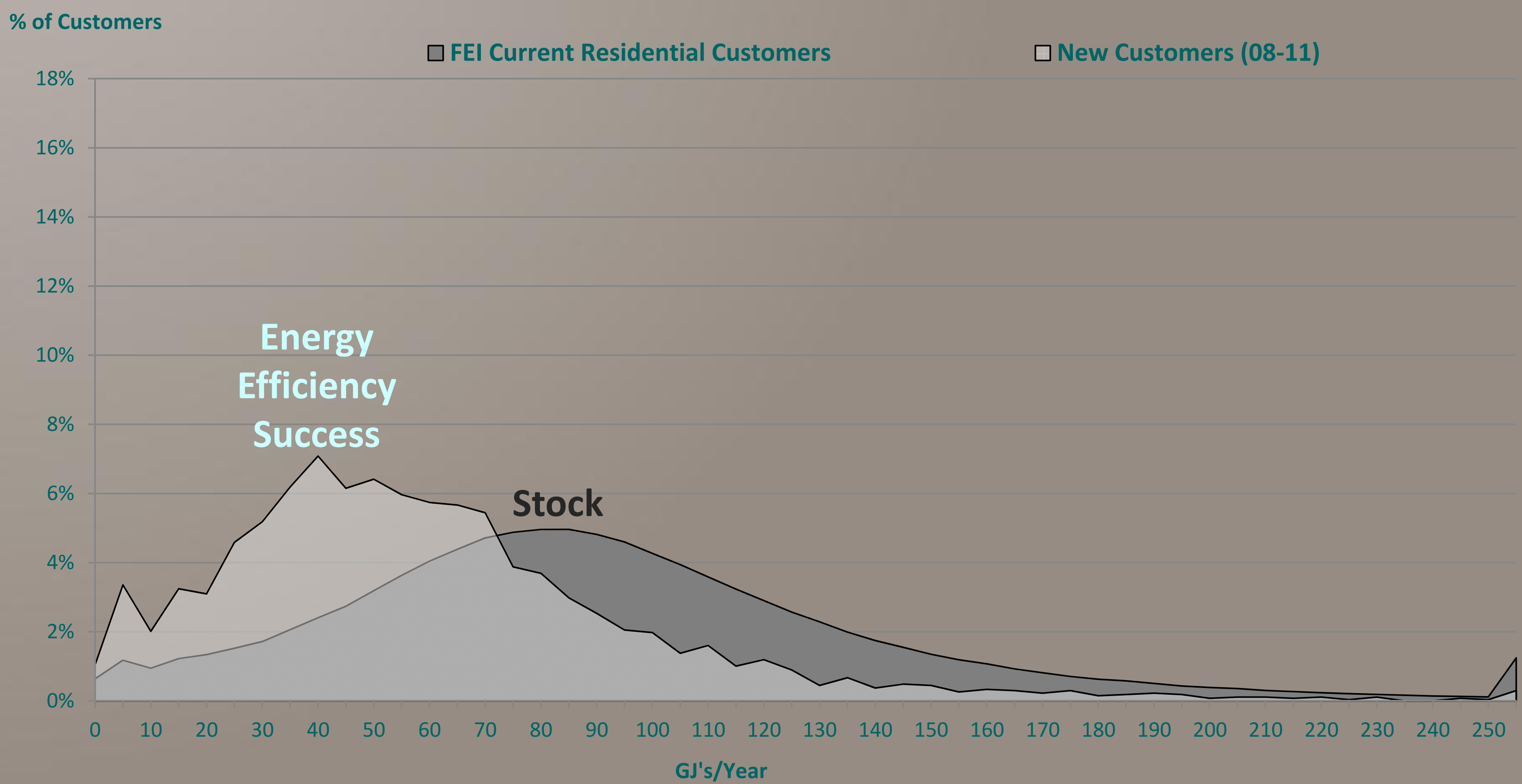
System Extension History in BC



*Source 2012 REUS

How We Serve Our Customers

Evolving Use of Natural Gas



How We Serve Our Customers

Our System Extension Customers

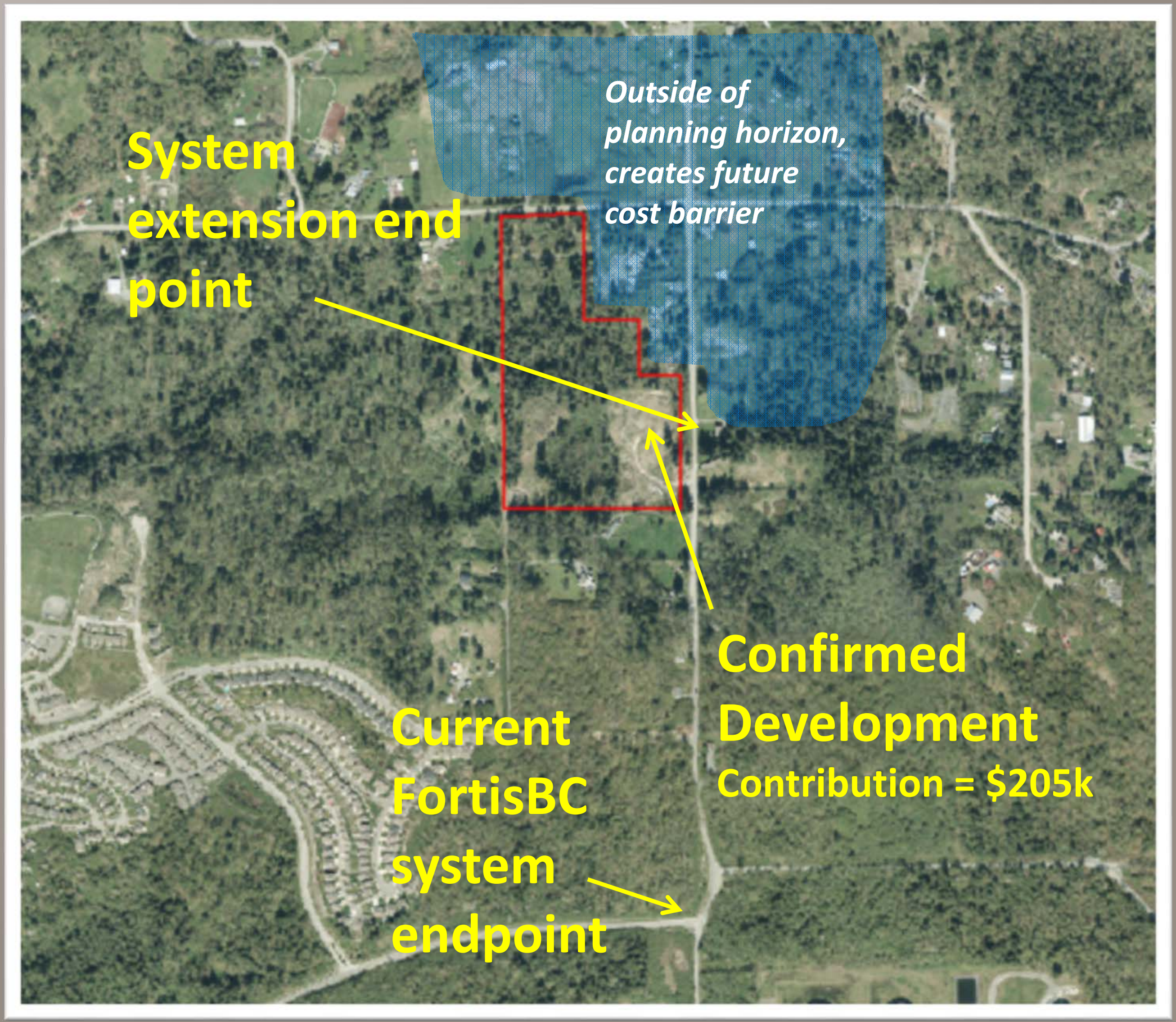
Builder/ Developer

Homeowners/ Renters

Off-System Communities

Customer Needs

Builder/Developer



- Feedback from Stakeholders…

-Return on Investment

-Focus on Costs

-Need a longer time horizon

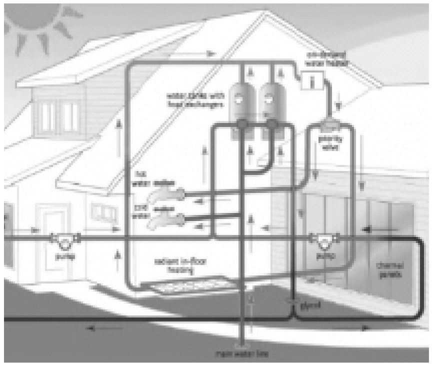
Customer Needs

Homeowners/Renters

Appliances

Behavior

Energy Efficiency Measures



- ❑ Feedback from Stakeholders…
  - *-Reduce home energy costs*
  - *-Simplified and affordable pricing*
  - *-Energy Efficiency*

Customer Needs

Off-System Communities

- Feedback from stakeholders…

  -Fairness

  -Provide us with an affordable choice

  -Consistency with Provincial LNG strategy

Utility Comparisons

General Approaches

Method	Utilities
Cost-benefit approach	■ FEU - MX Test ■ Other Canadian, WA Gas Utilities
Standard credit per customer	■ BC Hydro ■ FortisBC - Electric
Standard distance allowed per customer	■ OH – Dominion Gas
Standard credit per appliance	■ OR - Northwest Natural ■ CA – PG&E, So Cal Gas, SDG&E

Workshop #1 Summary

- Gaps in current system extension test related to customer types
  - Energy Efficiency
  - Simplified and Affordable Pricing
  - Longer Time Horizon
  - Fairness and Energy Choice

- Support to proceed with second workshop to discuss framework for policy review

System Extension Policy Review: Terms of Reference

Project Purpose & Process

Purpose

- ❑Stakeholder initiative to address gaps with FortisBC's current natural gas system extension policies

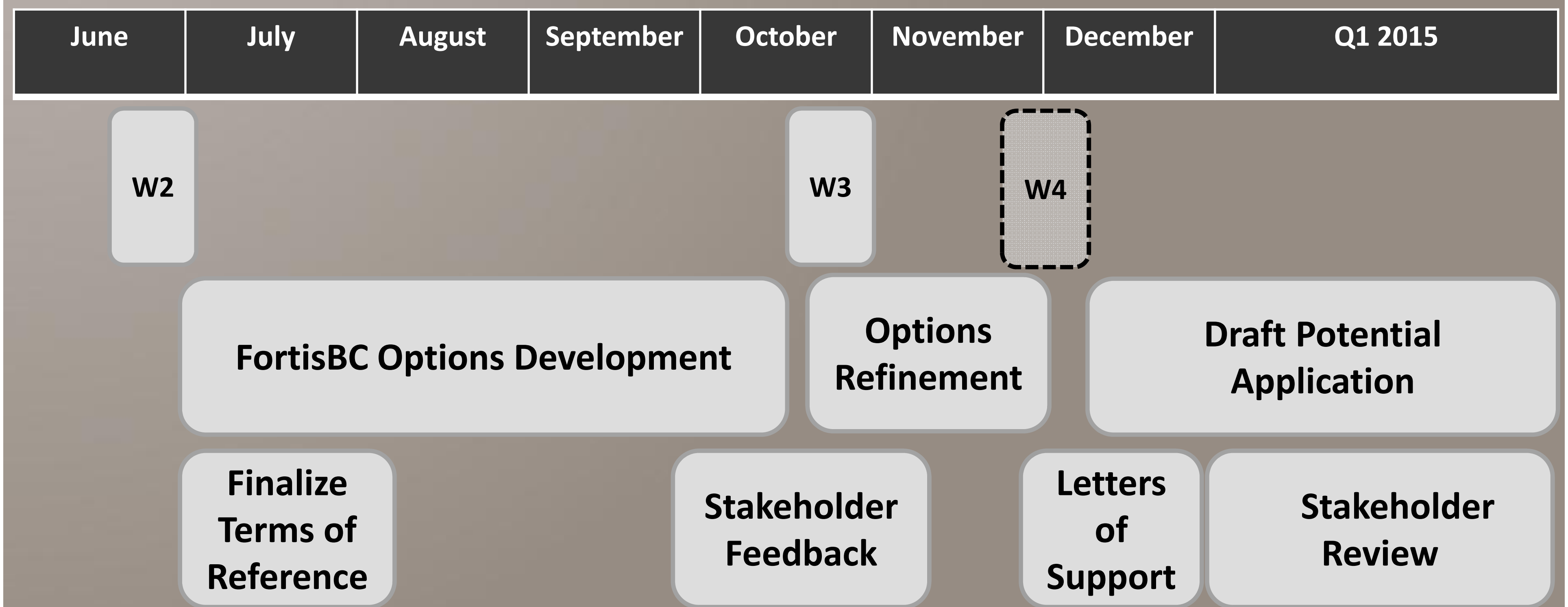
Process

- ❑Consultation via workshops
- ❑Stakeholder consensus through letter of support
- ❑Potential application

Roles & Responsibilities

Role	Participant	Responsibility
Governance	FortisBC	Options Development
Governance	Commission Staff	Review and Feedback
Stakeholder	All other Participants	Review and Feedback
Consultative	EES Consulting	Data Analysis and Review as Needed
Next Workshop – "Options Discussion" - October		

Timeline


June
July
August
September
October
November
December
Q1 2015
W2
W3
W4
FortisBC Options Development
Options Refinement
Draft Potential Application
Finalize Terms of Reference
Stakeholder Feedback
Letters of Support
Stakeholder Review

Project Overview

Historic Precedent

- 1996 BCUC Guidelines
- Bonbright Principles
- Regulatory Construct
  - Service Lines
  - System Extensions
  - Certificate of Public Convenience & Necessity

+

Changing Conditions

- Customer Feedback
- Transformed Market
  - Supply Growth
  - Resource Development Strategy
  - Greenhouse Gas Act
  - Competitive Energy Costs
  - Amalgamated Rates & Rate Design

=

Scope

- Infill Customers
- System Extension Customers
- Off-System Communities
- Uneconomic Customers

Historic Precedent

Guidelines and Principles

1996 Guidelines

- Lifetime impact of the main or service
- Social and utility perspectives
- Full scope of costs

2007 Revision Application

- Simple to understand
- Encourage energy conservation
- Easy to administer

Bonbright

- Fairness
- Stability
- Competitiveness

Historic Precedent

Current Regulatory Construct

Project Type	Regulatory Construct	Customer
• Infrastructure • Transmission Systems • Distribution Extensions over $5 million*	CPCN *(Certificate of Public Convenience and Necessity)*	• A connection request at the "community" level must undergo a detailed CPCN application process*
• Distribution System Extensions	System Extension Test and Policies	• All main extension requests are currently subjected to the Company's System Extension Test
• Service Line Connections	SLCA *(Service Line Cost Allowance)*	• Infill residential and small commercial customers fall under a Cost less SLCA calculation • Calculated using System Extension Test above

Changing Conditions

Customer Feedback

Protect Existing Ratepayers	Reduce Barriers to Connect
Provide an Energy Choice	Domestic Use
Meet Government Policy Objectives	First Nations & Community Interests

Changing Conditions

Customer Feedback

Protect Existing Ratepayers

Reduce Barriers

Provide an Energy Choic

Meet Government Policy Objectiv

- Consideration of costs & revenue associated with a project

Changing Conditions

Customer Feedback

Protect Existing Ratepayers

Reduce Barriers to Connect

Domestic Use

First Nations & Community Interests

- Ensure competitiveness by allowing utility to attract new customers
- Energy efficiency accessibility
- Consider benefits over full life of asset
- Simplified and affordable pricing

Changing Conditions

Customer Feedback

Protect Existing Ratepayers

Provide an Energy Choice

Meet Government Policy Objectives

- Give customers access to the most affordable energy option
- Consideration of social benefits
- Recognize needs of homeowners and businesses

Changing Conditions

Customer Feedback

- Competitiveness with BC LNG Strategy
- Recognize needs of “off-system” communities

Reduce Barriers to Connect

Domestic Use

First Nations & Community Interests

Changing Conditions

Customer Feedback

Protect Existing Ratepayers

Provide an Energy Choice

Meet Government Policy Objectives

- Economic development
- Greenhouse gas reduction
- Energy Efficiency

Changing Conditions

Customer Feedback

- Recognize benefits of domestic use for residential, business and industry for First Nations communities
- Affordable access

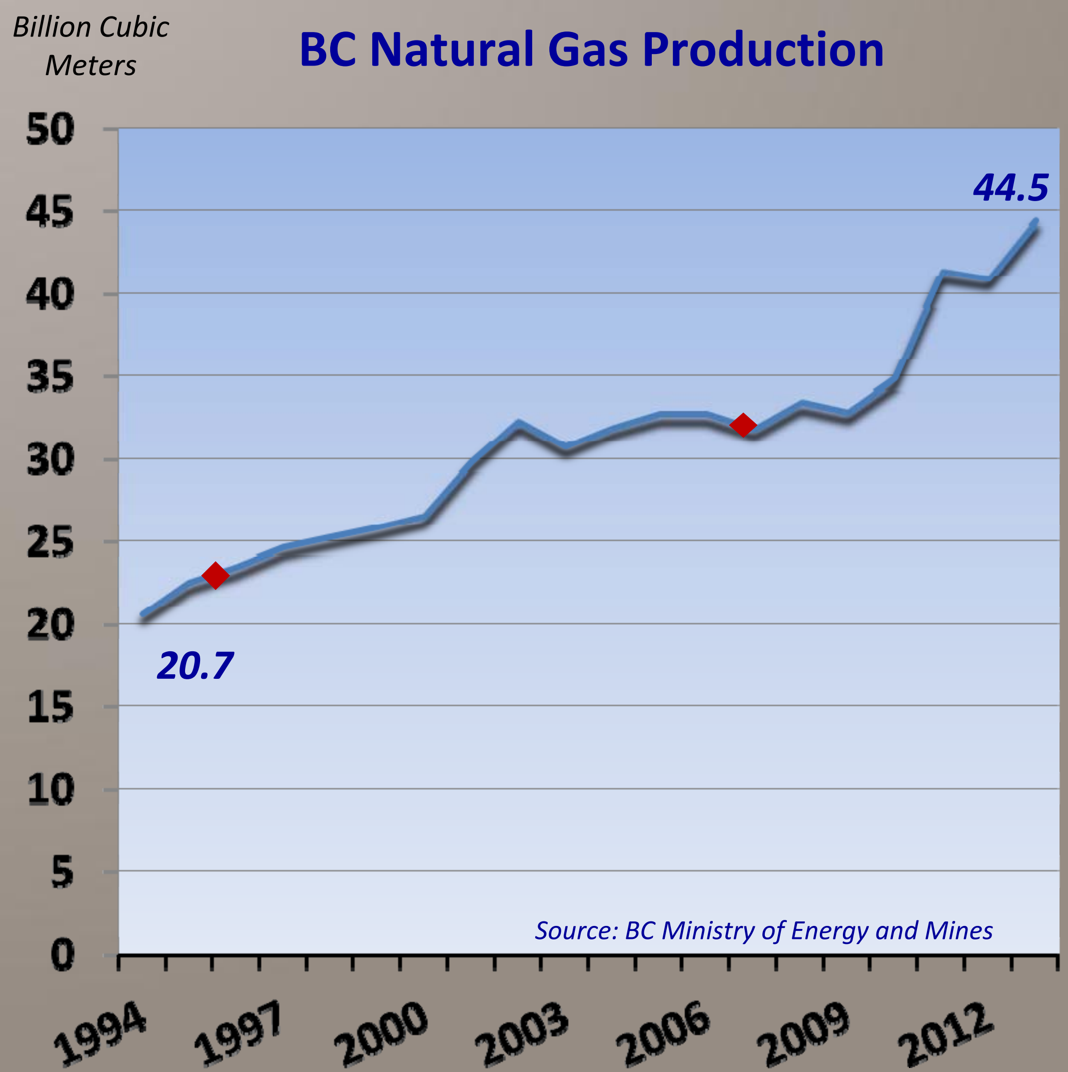
Reduce Barriers to Connect

Domestic Use

First Nations & Community Interests

Changing Conditions

Transformed Market

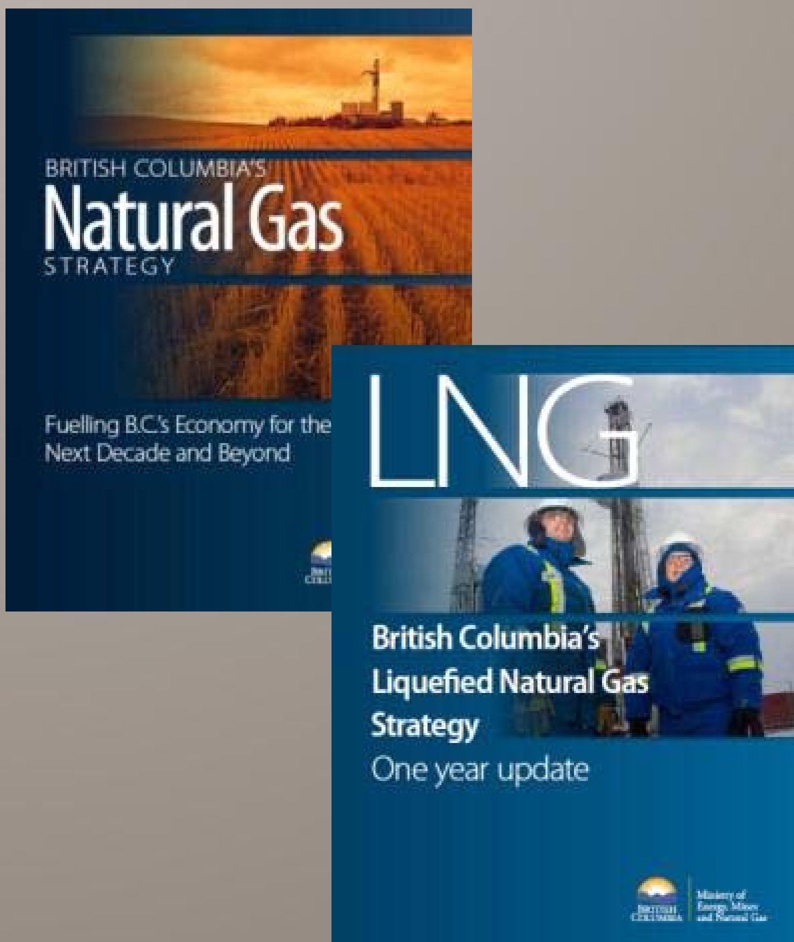


- Total Future Gas in Place Exceeds 2,900 TCF
- 150 Years of Supply

-System Extension Guidelines
-Policy Review

Changing Conditions

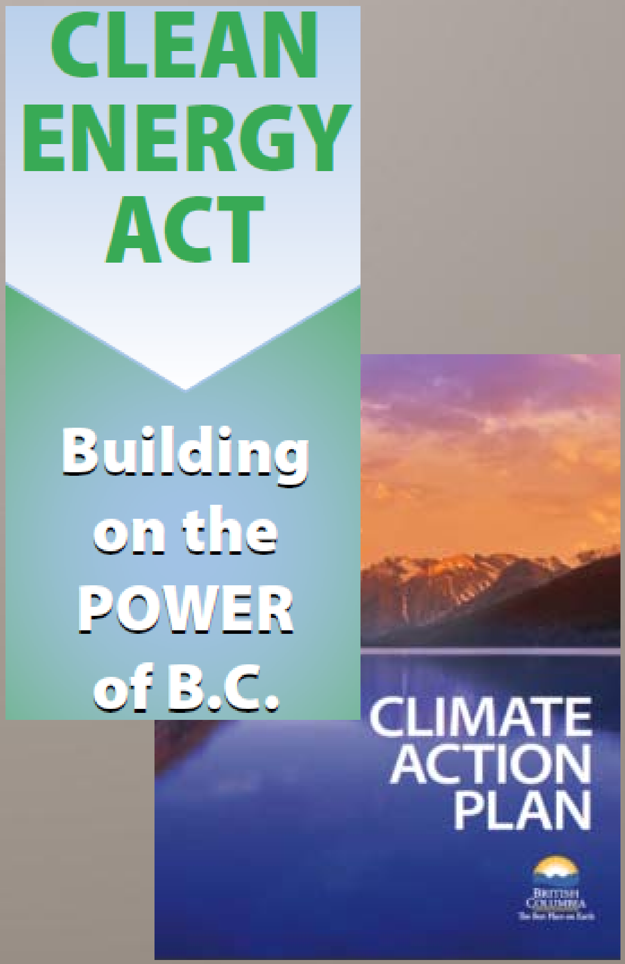
Government Objectives



- ❑ *Greater emphasis on market diversification to increase the value of B.C.'s natural gas.*
- ❑ *A redefinition of the Province's self-sufficiency policy to ensure B.C. is well-positioned to power expansion*

Changing Conditions

Government Objectives



- ❑ 2007 Greenhouse Gas Reduction Targets Act
- ❑ 2008 Climate Action Plan
- ❑ Carbon Tax Act
- ❑ 2010 Clean Energy Act

Customer Types
In-Fill Customers

Scope

	Description	Regulatory Construct	Scope
Infill Customers	Customers with distribution infrastructure at their location	Customer charges are based on SLCA*, which is a function of current system extension test	• SCLA • Life of Main or Service • Energy Efficiency • Appliance Signals

**Current Service Line Cost Allowance = $1535*

Customer Types
System Extension Customers

Scope

	Description	Regulatory Construct	Scope
System Extension Customers	Customers within local proximity to existing infrastructure	Customers are valued using the current system extension test	• System Extension Test • Life of Main • Energy Efficiency • Appliance Signals • Time Horizon

Customer Types

Off-System Communities

Scope

	Description	Regulatory Construct	Scope
Off System Communities	Communities with no distribution infrastructure at their location	CPCN	• Explore connection options • Define a mechanism

Scope

	Description	Regulatory Construct	Scope
Uneconomic Customers	Customers who are required to pay a construction related charge in order to connect to the system	There is currently no mechanism to provide assistance to customers who fall into this category	• Contribution in Aid of Construction • Time Horizon • Financing

Project Timeline

Date	Event	Topic	Goal	Status
Q4 2013	Individual Stakeholder Consultation	Initial Consultation	Garner Stakeholder support to begin review process.	Complete
February 18, 2014	FortisBC System Extension Stakeholder Workshop #1	Policy Issues	Introduction to current issues and agreement to proceed with exploration of policy alternatives.	Complete
June 18, 2014	FortisBC System Extension Stakeholder Workshop #2	Term of Reference & Guiding Principles	Stakeholder feedback on principles and objectives which to be used to form the foundation of policy options.	Complete
October 2014	FortisBC System Extension Stakeholder Workshop #3	Options Discussion	Review system extension options as developed by Fortis and Stakeholders and opportunity for questions and changes.	TBD
November 2014	FortisBC System Extension Stakeholder Workshop #4	Options Discussion	Continuation of Workshop #3 (as needed)	TBD
November 2014	Letters of Support		Stakeholder feedback finalized	TBD
Q1 2015	Potential Application	Potential Application	Consideration of potential application to Commission	

Stakeholder Package for June 18th (Tentative) Workshop

PART 1: Introduction

The purpose of this document is to outline the following:

- The key findings from the initial system extension review Stakeholder workshop held on February 18, 2014
- The terms of reference for the proposed system extension review (the "Project")
- The guiding principles of the Project

Request to Stakeholders

We are asking Stakeholders to review the entire document and provide comments, suggestions and to include any specific objectives they see as relevant to the workshop process. Please forward to mike.metza@fortisbc.com by June 5, 2014. FortisBC will then incorporate all Stakeholder comments in advance of the next Project workshop, tentatively scheduled for June 18, 2014.

PART 2: Background

On February 18, 2014 FortisBC held an initial System Extension Stakeholder Workshop. The primary focus of the workhop was to provide Stakeholders with a general understanding of current System Extension Policies and their role in connecting new customers to FortisBC's natural gas distribution system.

Throughout the workshops, participants heard from several Stakeholders who spoke to a range of issues such as the different types of new gas customers and their unique and sometimes contrasting needs when it comes to making an efficient energy choice, the challenges faced by off-system communities in meeting their specific energy needs, and a comparison and discussion of the system extension policies of other utilities in Canada and the Pacific Northwest.

A key finding from the workshops was a general consensus among Stakeholders that there are gaps in FortisBC's System Extension Policies in terms of addressing the needs of the different types of customers. In light of this finding, participants agreed to continue with a consultative review of the Company's system extension policies.

PART 3: Project Terms of Reference

The following section outlines the Terms of Reference for the Project. Specifically this refers to the Project purpose, scope, roles and responsibilities, deliverables and timelines.

Purpose

This Project is a Stakeholder driven initiative designed to address potential inadequacies with FortisBC's current natural gas system extension policies and Main Extension ("MX") Test. The Project will, as needed, provide consultation, analysis and recommendations on these policies based on the feedback of Stakeholders.

Recommendations from this project will form the foundation for a potential application from FortisBC to the British Columbia Utilities Commission (the "Commission").

Scope

Included in the Project scope are the following:

- Regulatory natural gas connection policies as they relate to potential distribution customers.

  a. Infill Customers: Customers who are located within the Companies distribution service territory and require a service connection to existing natural gas infrastructure already at their location.

  b. MX Customers: Customers who are within a local proximity to the Company's current distribution system and require a main extension to their location before a service connection can be provided.

  c. Off-System Customers: Customers who require, but do not currently have any natural gas distribution infrastructure within their community.

- Specific pricing mechanisms as they relate to new distribution customers.

  a. Infill Customers: Application Fees & Service Line Cost Allowance methodologies and calculations.

  b. MX Customers: Main Extension Test structure and assumptions, economic parameters, attachments and consumption/revenue calculations.

  c. Off-System Customers: Define a mechanism to balance the economic feasibility and social aspects of providing natural gas service to Off-System communities.

- Treatment of individual customer classes based on rates and consumption.
  - The application of specific MX test assumptions and parameters based on a customer's rate class (residential, commercial and industrial).

- Treatment of "uneconomic" customers (required to contribute to connection cost) as they pertain to Off-System communities.

- The treatment of uneconomic MX or infill customers:
    - Contribution Financing
    - Refundable Mains
    - Contributory Thresholds

Excluded from Scope:

- Any services or main extensions that would traditionally fall under a CPCN application where the system extension costs are greater than $5 million.

Roles and Responsibilities

As summarized in the table below, there are three Project roles for participants: Governance, Stakeholder and Consultant.

Governance Role	Stakeholder Role	Consultant Role
FortisBC	**BC Hydro**	**EES Consulting**
Commission Staff	**CEC – Commercial Energy Consumers Association BC**	
	MEM – BC Ministry of Energy and Mines	
	MLA – Boundary Similkameen	
	OSRD – Okanagan Similkameen Regional District	
	PIAC – Public Interest Advocacy Centre	
	PNG – Pacific Northern Gas	
	PRRD – Peace River Regional District	

The responsibilities of each of the three Project roles are as follows:

Governance Role

- Provide leadership throughout the workshops and options development
- Co-ordinate meetings and chair workshops.

Stakeholder Role

- Attend workshops and participate in all aspects of policy exploration and formulation
- Review and comment on data analysis and results if applicable.

Consultant Role

- Review and comment on data analysis and results as needed.

Deliverables

FortisBC will integrate Stakeholder feedback in the exploration and development of two main deliverables:

1) Terms of Reference & Guiding Principles. The tentatively scheduled June 18th workshop will cover this subject.
2) System extension options. Following the June 18th workshop, FortisBC will develop system extension options for review with Stakeholders in subsequent workshops.

At the conclusion of the Project, FortisBC will consider a potential application to the Commission based on the outcome of the Project.

Timeline

The Project timeline is summarized in the table below:

Date	Event	Topic	Goal	Status
Q4 2013	Individual Stakeholder Consultation	Initial Consultation	Garner Stakeholder support to begin review process.	Complete
February 18, 2014	FortisBC System Extension Stakeholder Workshop #1	Policy Issues	Introduction to current issues and agreement to proceed with exploration of policy alternatives.	Complete
June 18, 2014* Tentative	FortisBC System Extension Stakeholder Workshop #2	Term of Reference & Guiding Principles	Stakeholder feedback on principles and objectives which to be used to form the foundation of policy options.	Upcoming
September 2014	FortisBC System Extension Stakeholder Workshop #3	Options Discussion	Review system extension options as developed by Fortis and Stakeholders and opportunity for questions and changes.	TBD
October 2014	FortisBC System Extension Stakeholder Workshop #4	Options Discussion	Continuation of Workshop 3 (as needed)	TBD
Q1 2015	Potential Application	Potential Application	Consideration of potential application to Commission	

PART 3: Guiding Principles

This section is intended to form the initial policy foundation for any future system extension policy enhancements to be considered in the Project. It is organized into three sections covering the following:

- The background on relevant guiding principles from historical Commission proceedings
- The change in market conditions since the most recent Commission proceedings
- The proposed updates to historical guiding principles

Background

1996 Utility System Extension Test Guidelines

This following list briefly summarizes some of the voluntary guidelines[1] that were developed and issued by the Commission under order G-80-96[2] which subsequent to a hearing and reconsideration decision on Utility System Extension Tests during the late 1990's.

- Evaluation of system extension should include all benefits and costs over a time period long enough to consider the full impact of the extension.
- System extensions should be evaluated from a social perspective and a utility perspective.
- System extension costs should include pre-construction estimates of the construction costs, system improvement costs, O&M costs, revenues and a reasonable consideration of externalities (for the social perspective evaluation.)
- Utilities should come forward with options for connection fees that send an appropriate signal about the net social costs of less efficient energy use.

2007 Terasen Utilities System Extension and Customer Connection Policies Review Application[3]

The items below highlight some of the key considerations Terasen put forward as the basis for the modifications requested in the application. The Companies stated that system extension policies should:

- Signal better value for customers wishing to attach to the system.
- Measure the right factors, be simple to understand and administer with results that send the appropriate economic signal to the customer.
- Encourage energy conservation through the test and attachment policies
- Encourage the "right fuel" choice. The Companies believe that natural gas is the appropriate fuel for space and water heating applications and that the connection policies and tests should send the appropriate signal to customers for these energy choices.

The Companies' proposed modifications to its system extension policies were approved under Commission Order G-152-07[4].

Bonbright Principles

The following list has been developed by FortisBC through defining common utility objectives surrounding system extension tests through the context of the Principles of Public Utility Rates, by James C. Bonbright. (The "Bonbright Principles"). Bonbright principles have been referred to in various applications by the Companies, and, as such, they help form the foundation for future system extension policy considerations.

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[1] 1996 Utility System Extension Test Guidelines – September 5, 1996
[2] British Columbia Utilities Commission Order G-80-96 – August 9, 1996
[3] Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. System Extension and Customer Connection Policies Review Application - July 31, 2007
[4] British Columbia Utilities Commission Order G-152-07 – December 6, 2007

- Customer Impact: Ensures changes do not create unacceptably high charges to new or existing customers.

- Fairness: Ensure fairness between customers in terms of both cost causation and similar treatment over time, recognizing the changes in housing environment, technology and natural gas usage patterns of new and existing customers. Also plus recognizes the needs of "off-system" communities who require natural gas connections.

- Economic Efficiency: Recognizes energy efficiency and conservation at the time of construction for new connections and in the trade-off between main extension policies and rate impacts.

- Stability: Reflects long-term objectives that will not lead to frequent changes so that customers know what to expect over time.

- Ease of Understandability: Allows customers to understand the policies and therefore be able to make appropriate choices, as well as making policies easy to administer.

- Competitiveness: Allows for competitiveness of the utility to attract new customers relative to competing gas utilities as well as alternative fuels.

- Recovering the Cost of Service: Allows for full recovery of utility costs either through main extension policies or rates, and recognizes the trade-offs between the two revenue sources.

Changing Market Conditions & Guiding Principle Considerations

The marketplace has undergone several significant changes since the last review in 2007. These changes and the resulting policy considerations follow.

Since the time of the development of the original utility system extension guidelines by the Commission in 1996, and a review of system extension policies in 2007, the BC natural gas industry as a whole has undergone substantial change. Supply outlooks reversed from an imminent dwindling of supplies and a scramble to find and import LNG, to today, where BC has now become a leading exporter of natural gas to Canada, the US and global markets with supplies forecast beyond the next 100 years[5]. Prices have gone from a high and volatile to a low and relatively stable environment. The BC Government is now focusing on developing this vast resource to through an LNG and natural gas for transportation strategy. Although the residents of BC recognize the benefits of developing this resource, FortisBC has become increasingly

[5] Spectra Energy presentation at PNUCC Power and Natural Gas Planning Taskforce meeting April 11, 2014

aware of the desire of various Stakeholders to be given a choice when it comes to their energy needs and to be given reasonable access to the natural gas reserves in the province for their local energy needs.

Although not a comprehensive list, below are several key system extension policy considerations that will help to define future policy options to be explored in the Project.

Economic Lifespan:

The current system extension test used by the Companies provides an estimate of the revenue and cost associated with a new service or main and its impact on existing ratepayers. Current policies are designed to consider a customer's worth over a timeframe that is less than half the length of time the asset would be in use. Since evaluation of system extension should include all benefits and costs over a time period long enough to consider the full impact of the extension, and, the current policy does not meet this criteria, economic lifespan should therefore be considered in the Project.

Fairness, Competitiveness & Energy Efficiency Signals:

Current system extension policies were developed during a period of lower energy efficiency and high use per customer and since that time overall use per customer has been falling. This decline is a positive change as technology improvements and appliance upgrades result in a more efficient use of resources. However, through the lens of the Company's main extension test, where a customer is valued based on the amount of gas they consume, a customer today would not be treated in the same manner as an existing customer. It can be argued that the Bonbright principle of fairness and competitiveness are not adhered to in the current policies, so, these issues should be considered in the Project. Furthermore, the existing system policies are limited in the recognition of the benefits of using more efficient appliances so; this issue should be considered in the Project.

Access to Natural Gas Service for Off-System Communities:

Current policies are designed to assess value and connect customers who are within local proximity to natural gas distribution infrastructure. Communities who do not have natural gas infrastructure are challenged under the current system extension test to achieve reasonable access to natural gas to provide them with an energy choice. The current system extension policy is limited in evaluating social perspectives and externalities, so, this issue should be considered in the Project.

System Extension Stakeholder Workshop #3

FORTIS BC

Event Details:

Date:	Wednesday October 8th, 2014
Time:	7:30 AM – 4:00 PM
Location:	Conway Room (6th Fl.) - The Shangri-La Hotel 1128 West Georgia Street Vancouver, BC V6E 0A8 604-689-1125 http://www.shangri-la.com/vancouver/

Contact: Mike Metza
Energy Products & Services Manager
Tel: 604-592-7852
Cell: 604-790-5334
Fax: 604-592-7620
mike.metza@fortisbc.com

Agenda:

Time	*Topic*	*Details*	*Presenter*
7:30-8:30	**Registration – Breakfast Provided**		
	Introduction	• Meeting Objectives • Project Overview	Jason Wolfe – Fortis BC
	Rate Impacts	• Rate Impacts of Growth • Social Benefits and Discussion	Gail Tabone – EES Consulting
10:00-10:20	**Break**		
	New Customer Connections: System Extension Test	• System Extension Test Considerations • Proposed Changes	Mike Metza – Fortis BC
12:00-1:00	**Lunch Provided**		
	New Customer Connections: Service Line Cost Allowance	• Review of Approved Methodology • SLCA Update	Mike Metza – Fortis BC
	New Customer Connections: Off System Communities and First Nations	• Off System Community Considerations • Conceptual Framework	Brent Graham – Fortis BC
2:15-2:35	**Break**		
	Performance and Reporting	• Reporting Structure and Considerations • Review and Update of 2008 Mains	Brent Graham – Fortis BC
	Closing	• Workshop Summary • Next Steps	Brent Graham – Fortis BC
4:00	**End**		

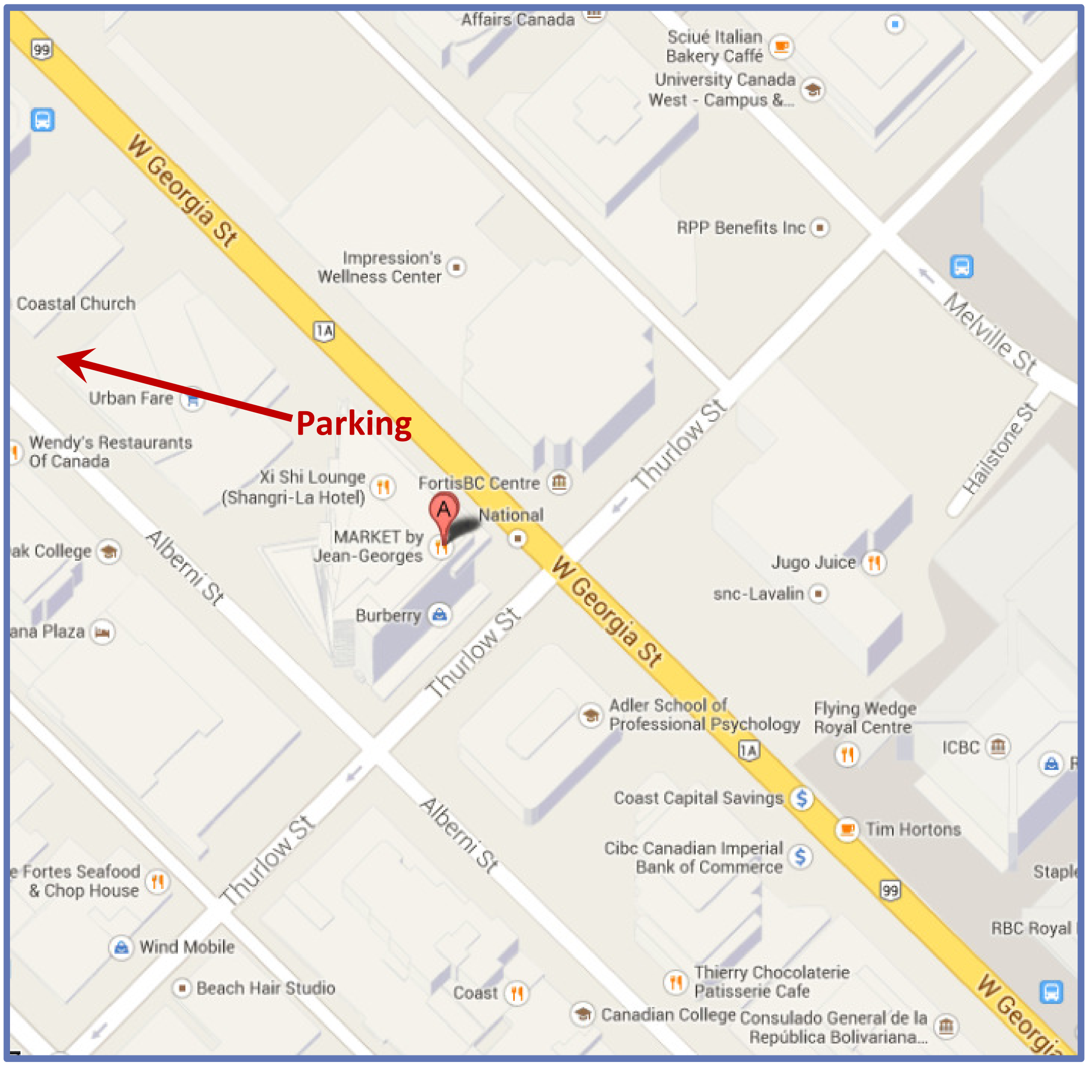
Special Notes:

- There is a valet parking at the hotel and vouchers will be given out at the registration table. Please have your parking stub with you.
- Coffee and beverages will be provided throughout the day.

List of Confirmed Attendees:

Name	Title	Stakeholder
Justin Miedema	Senior Regulatory Advisor, Rates and Regulatory	BC Hydro
Kevin Lim-Kong	Policy Specialist, Customer Interconnections & Policy	BC Hydro
Frank Lin	Director, Interconnections and Shared Assets	BC Hydro
Rena Messerschmidt	Policy Manager, Customers Interconnections & Policy	BC Hydro
Katherine Muncaster	Acting Director, Energy Efficiency Branch	BC Ministry of Energy and Mines
Rob Wood	Acting Director, Major Investments Office	BC Ministry of Jobs Tourism and Skills Training
William J Andrews	William J. Andrews, Barrister & Solicitor	B.C. Sustainable Energy Association & Sierra Club B.C.
Thomas Hackney	Case Manager	B.C. Sustainable Energy Association & Sierra Club B.C.
Suzanne Sue	Senior Regulatory Specialist	BC Utilities Commission
Chris Garand	Engineer, Infrastructure	BC Utilities Commission
Norman Florence	Band Council Member	Chawathil First Nation
David Craig	President, Consolidated Management Consultants	Commercial Energy Consumers BC
Gail Tabone	Senior Consultant, EES Consulting	EES Consulting Ltd.
Mike Metza	Energy Products & Services Manager	Fortis BC
Brent Graham	Manager, Energy Products & Services	Fortis BC
Jason Wolfe	Director, Market Development	Fortis BC
Dennis Swanson	Director, Regulatory Affairs	Fortis BC
Vanessa Connolly	Government Relations and Public Affairs Manager	Fortis BC
Dennis Adamson	Director, Electoral Area B	Fraser Valley Regional District
Lloyd Foreman	Director, Electoral Area A	Fraser Valley Regional District
Colleen Misner	Constituency Assistant to Linda Larson, MLA	MLA, Boundary-Similkameen
George Bush	Board Member	Okanagan - Similkameen Regional District
Janet Kennedy	Vice President, Regulatory Affairs and Gas Supply	Pacific Northern Gas
Peter Schriber	Manager, Financial Planning & Business Development	Pacific Northern Gas
Karen Goodings	Board Director	Peace River Regional District
Tannis Braithwaite	Executive Director	Public Interest Advocacy Centre
Chief Clem Seymour	Seabird Island Band Chief	Seabird Island Band
Brian Titus	Seabird Island Band Consultant	Seabird Island Band
Steven Patterson	Natural Resource Manager	Yale First Nation

Maps:


Affairs Canada
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Bakery Caffé
University Canada
West - Campus &...
W Georgia St
Impression's
Wellness Center
RPP Benefits Inc
Coastal Church
Melville St
Parking
Urban Fare
Wendy's Restaurants
Of Canada
Xi Shi Lounge
(Shangri-La Hotel)
FortisBC Centre
National
Thurlow St
Hailstone St
MARKET by
Jean-Georges
Alberni St
Jugo Juice
snc-Lavalin
Burberry
W Georgia St
Thurlow St
Adler School of
Professional Psychology
Flying Wedge
Royal Centre
ICBC
Coast Capital Savings
Tim Hortons
Cibc Canadian Imperial
Bank of Commerce
Alberni St
Thurlow St
& Chop House
Wind Mobile
Beach Hair Studio
Coast
Thierry Chocolaterie
Patisserie Cafe
Canadian College
Consulado General de la
República Bolivariana...
RBC Royal
W Georgia

FortisBC System Extension Review
Stakeholder Workshop #3

October 8, 2014

FORTIS BC™

Introductions:

Yale First Nation Government

Chawathil First Nation

Seabird Island Band

Regional District RDOS Okanagan-Similkameen

BC PIAC British Columbia Public Interest Advocacy Centre

Sierra Club BC

PRRD

British Columbia Utilities Commission

MLA Linda Larson Boundary-Similkameen

BC Sustainable Energy Association

British Columbia

CEC British Columbia

Fraser Valley Regional District

FORTIS BC

EES Consulting

PNG Pacific Northern Gas Ltd.

BC hydro

Workshop Objectives:

- Summary of Previous Workshops
- Understand Impacts of Growth on Customers
- Review Proposed Customer Connection Process
- Discuss Performance and Reporting
- Next Steps

FortisBC Objectives:

- Make it Easier for Customers to Attach to our System
- Encourage the Efficient Use of Natural Gas

Overview: Workshop 1 & 2

Terminology

Term	Definition
System Extension Test (Economic or MX Test) A forecasted calculation used to determine the economic viability of bringing natural gas to a new location • Potential number of customers • Gas Consumption Credit • Estimated Cost	Revenue ÷ Cost = Economic Test
Service Line Cost Allowance (SLCA) The credit amount received by a customer who already has gas on their street and only needs a service line. This credit helps offset the cost of the installation • Determined by the test above	$1535

Terminology

Term	Definition
Consumption Credit	The gas consumption credit for a customer is based on many factors such as: • Energy efficiency • Appliance type • Household size • Individual preference 
Contribution, “CIAC”	A contribution in aid of construction arises when the expected revenue from a customer is not enough to pass the “economic” threshold of system extension test *Expected Revenue* **1000** ÷ *Estimated Cost* **2000** = **0.5** *Customer must make a contribution*

Project Overview

Historic Precedent

- ❑ 1996 BCUC Guidelines
- ❑ Bonbright Principles
- ❑ Regulatory Construct
  - Service Lines
  - System Extensions
  - Certificate of Public Convenience & Necessity

+

Changing Conditions

- ❑ Customer Feedback
- ❑ Transformed Market
  - Supply Growth
  - Resource Development Strategy
  - Greenhouse Gas Act
  - Competitive Energy Costs
  - Amalgamated Rates & Rate Design

=

Scope

- ❑ Infill Customers
- ❑ System Extension Customers
- ❑ Off-System Communities
- ❑ Uneconomic Customers

Impacts of Growth on Customers

Impacts of Growth: Definitions

Term	Explanation
Rate Base	Value of all assets used to deliver natural gas
Cost of Service	All costs associated with the delivery of service to our customers.
Additions to Rate Base	Represents our actual dollars spent on new main extensions and services in the last 6 years
Rate Impact	The change in customer rates
Growth	The number of new customers, mains and service lines added to our distribution system
Average Consumption	The average actual gas usage per customer

Impacts of Growth: Methodology

FEU Amalgamation Cost of Service Application "COSA"

- *$ Cost of Service*
- *$ Total Rate Base Expenses*
- *Total Amount of Gas*
- *Total FEU Customers*

Original Costs

FEU Additions to Rate Base (2008-2013) "Growth"

- *$ Total Mains*
- *$ Total Services*
- *New Customers Added*
- *Total Consumption*

New Customers

Impacts of Growth: Methodology

Existing

1 Cost of service ($) ÷ Annual consumption (GJ) = $/GJ per customer

Existing + New

− **2** Cost of service including cost of new mains and services($) ÷ Annual consumption including new customers (GJ) = $/GJ per customer including new customers

---

Annual rate impact per customer

Impacts of Growth: Methodology

Base Case (Amalgamation Application)	**Low Case (Reduce Usage)**
Blended Residential, Commercial and Industrial	Blended Residential, Commercial and Industrial
150 GJ's per Customer	122 GJ's per Customer
No Change in O&M, General and Admin Expenses (ie) Accounting	25% Increase in Other Expenses

Impacts of Growth: Cost Savings for Existing Customers

Average Annual Mains and Services Spending (2008-2013): $23 Million

	Base Case (amalgamation)	**Low Case (reduced consumption)**
Annual Savings for Existing Customers at Current Expenditure Level	**$26**	**$15**
Scenario #1 Capital Spending Increase	**$100 Million**	**$50 Million**
Annual Savings for Existing Customers at New Expenditure Level	**$14**	**$7.50**
Scenario #2 Capital Spending Increase	**$200 Million**	**$100 Million**
Annual Savings for Existing Customers at New Expenditure Level	**$0**	**$0**

Impacts of Growth: Methodology

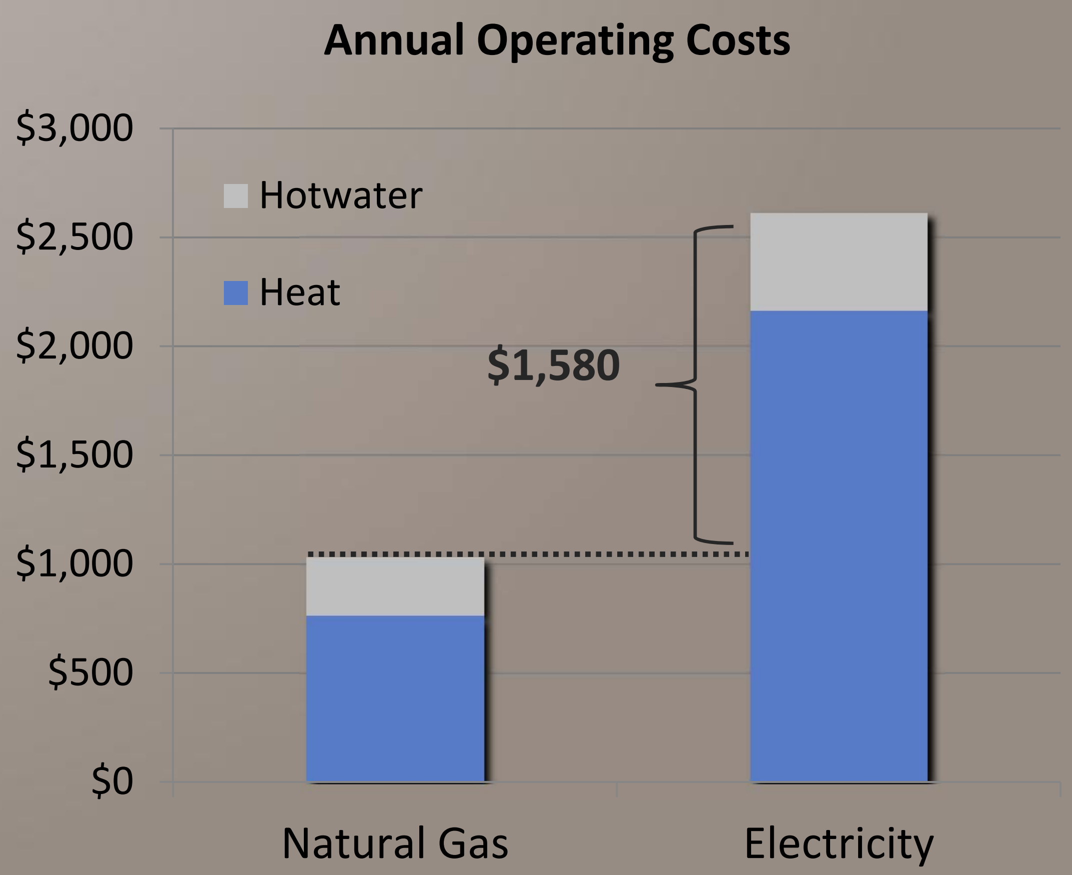
- ☑ Tables and Spreadsheets available
- ❑ Available to discuss methodology and details

Impacts of Growth: Social Benefits

- Avoided infrastructure
- Economic development
- More provincial royalties
- Potential to offset high carbon fuels
- New customer annual cost savings

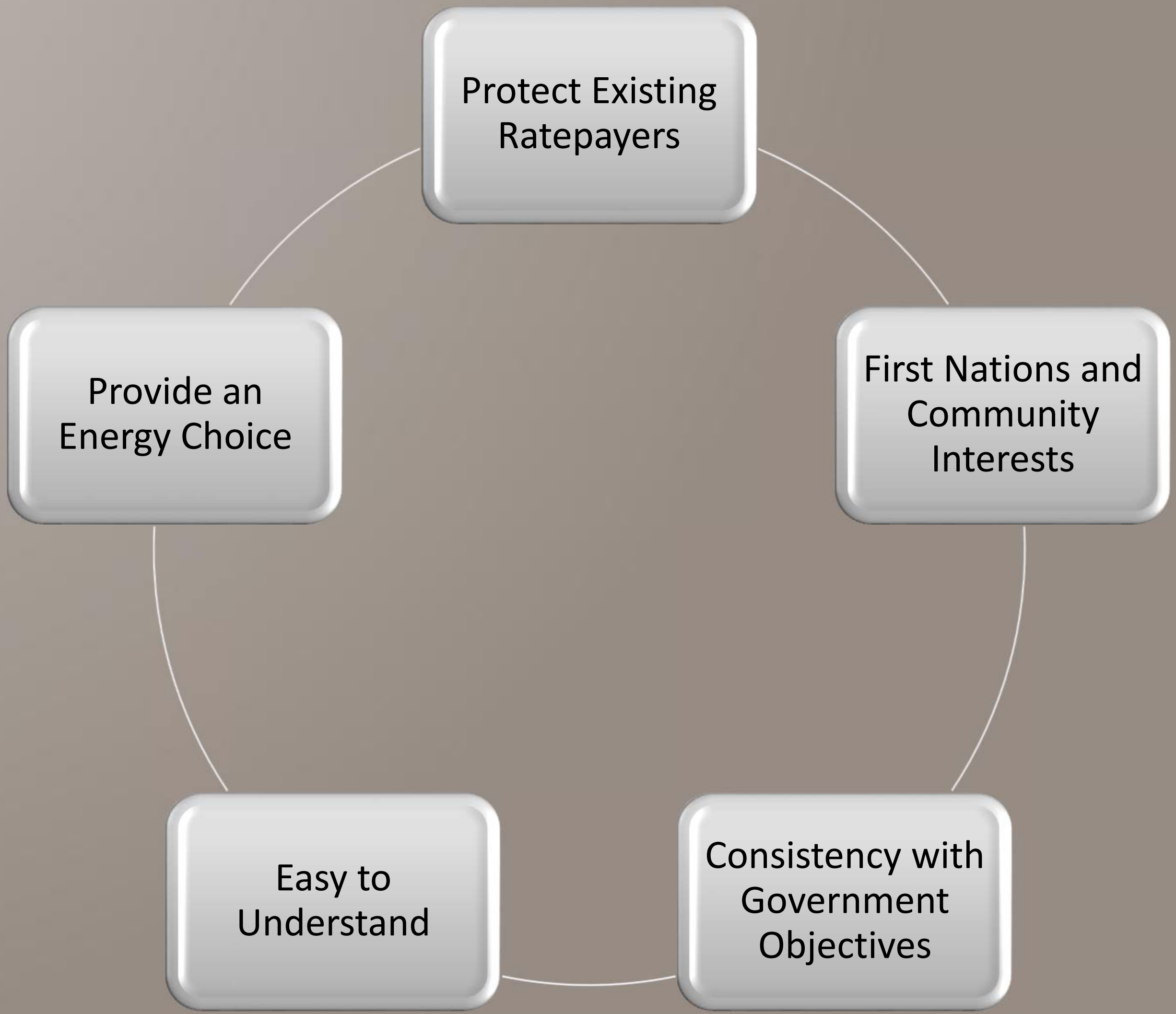
Impacts of Growth: New Customer Benefits

- Operating Cost Savings

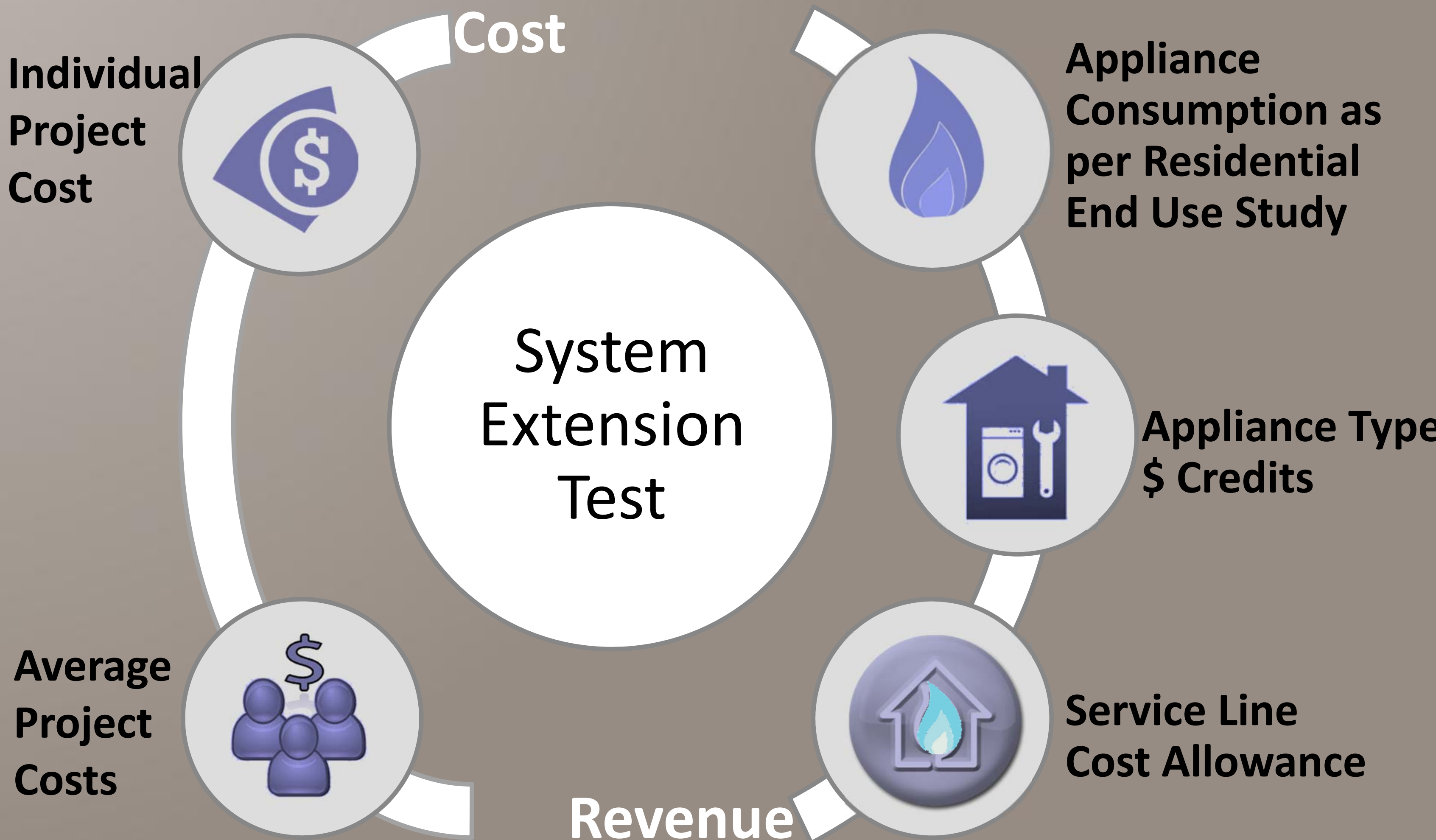


New Customer Connections

Stakeholder Guiding Principles



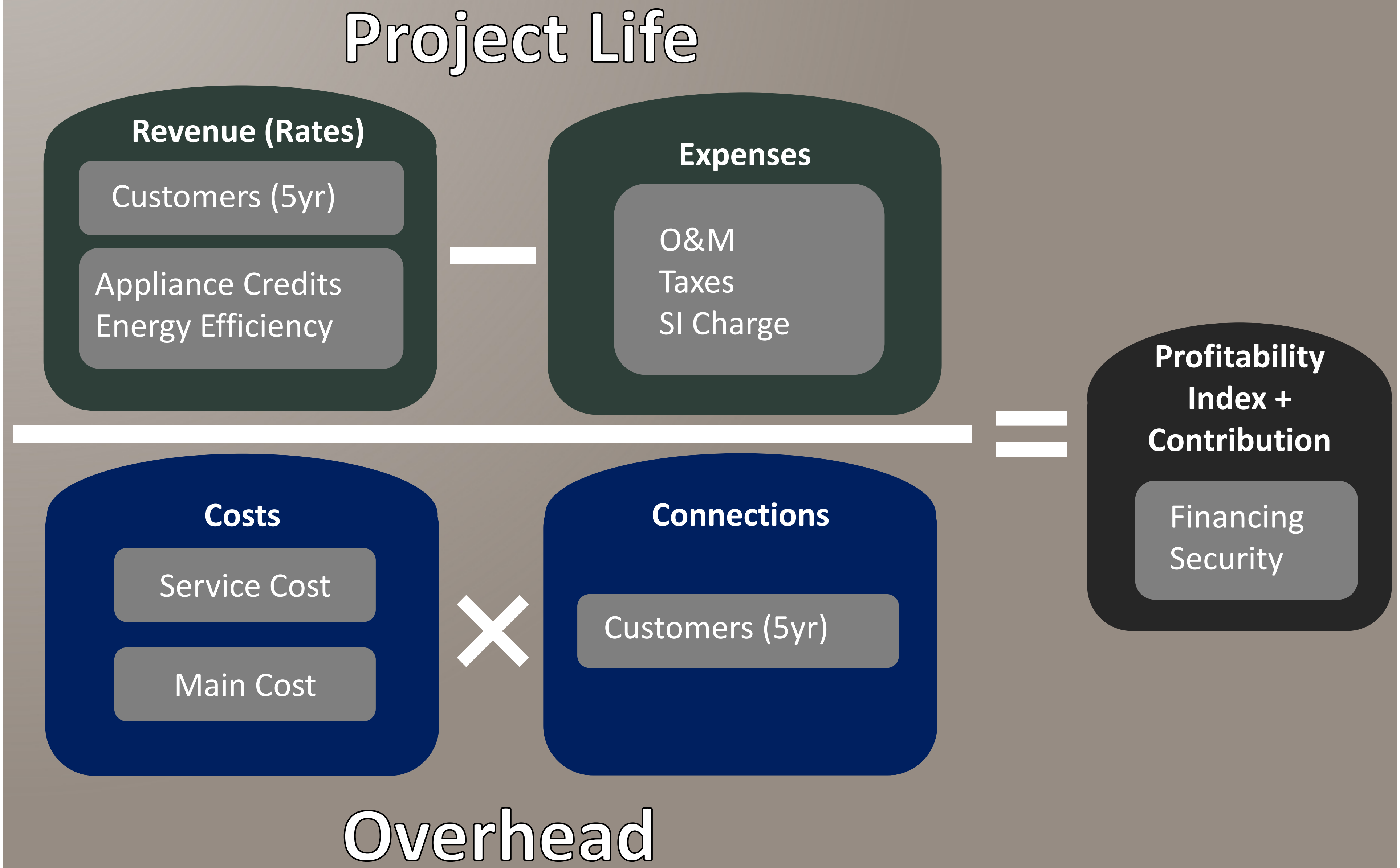
System Extension Options



New Customer Connections:

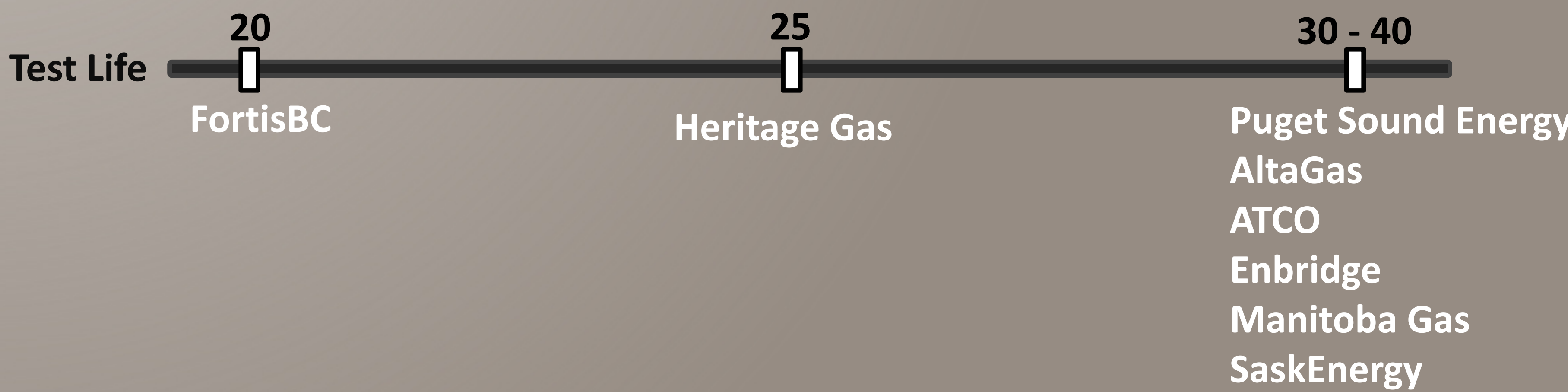
System Extension Test

System Extension Test Construct



Proposed Changes

Project Life



The use of a 20-year period is inconsistent with other utilities and is shorter than the useful life of the facilities in question.

Project Life

MX Parameter	New Project Time Frame	Rationale
Project Life	**40 years**	Match Project Life to the Asset Life

- 2012/13 Fortis BC revenue requirement application included the last approved depreciation study.
- 40 to 50 years matches the useful life of the asset and is consistent with other utilities.

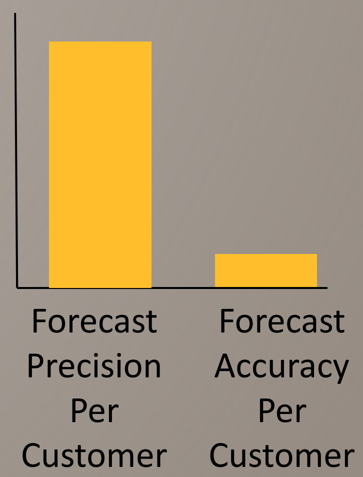
Attachment Window

MX Parameter	New Attachment Window	Rationale
Customer Attachment Window	**10 Years**	Change to allow for longer term build-out in neighborhoods, subdivisions and communities

- SaskEnergy Example:

1. Design infrastructure for an unserved area
2. Aggregate all capital costs
3. Include customer attachments for 10 years
4. Run system extension test

History of Appliance Forecasts (Revenue)



Pre 2002

- 110 GJ's credit to all customers
- Uses average consumption
- No "true-up"

2007

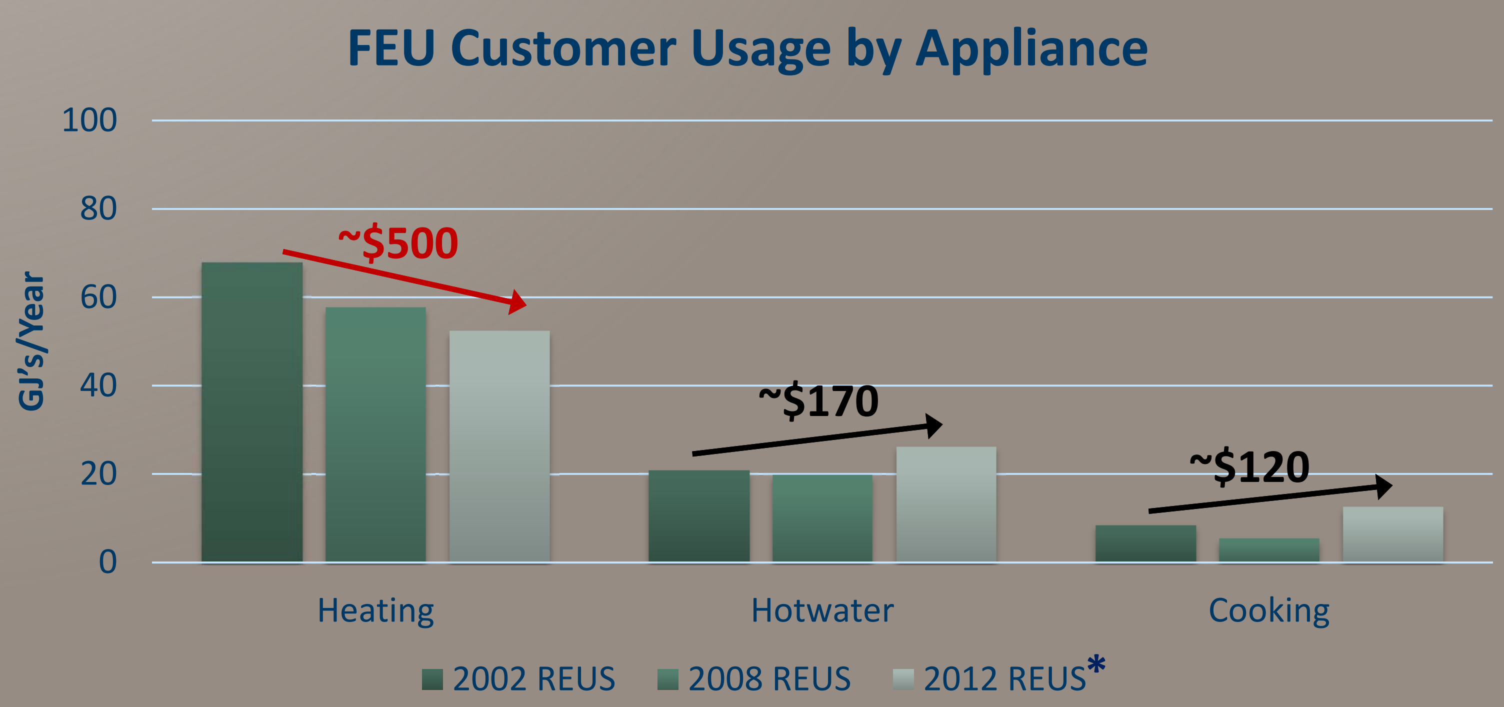
- Appliance specific credits
- Energy efficiency adders
- Customers credits based on location

2010 - Today

- Appliance specific credits update per REUS
- Extensive reporting comparing appliance credits to individual customer consumption

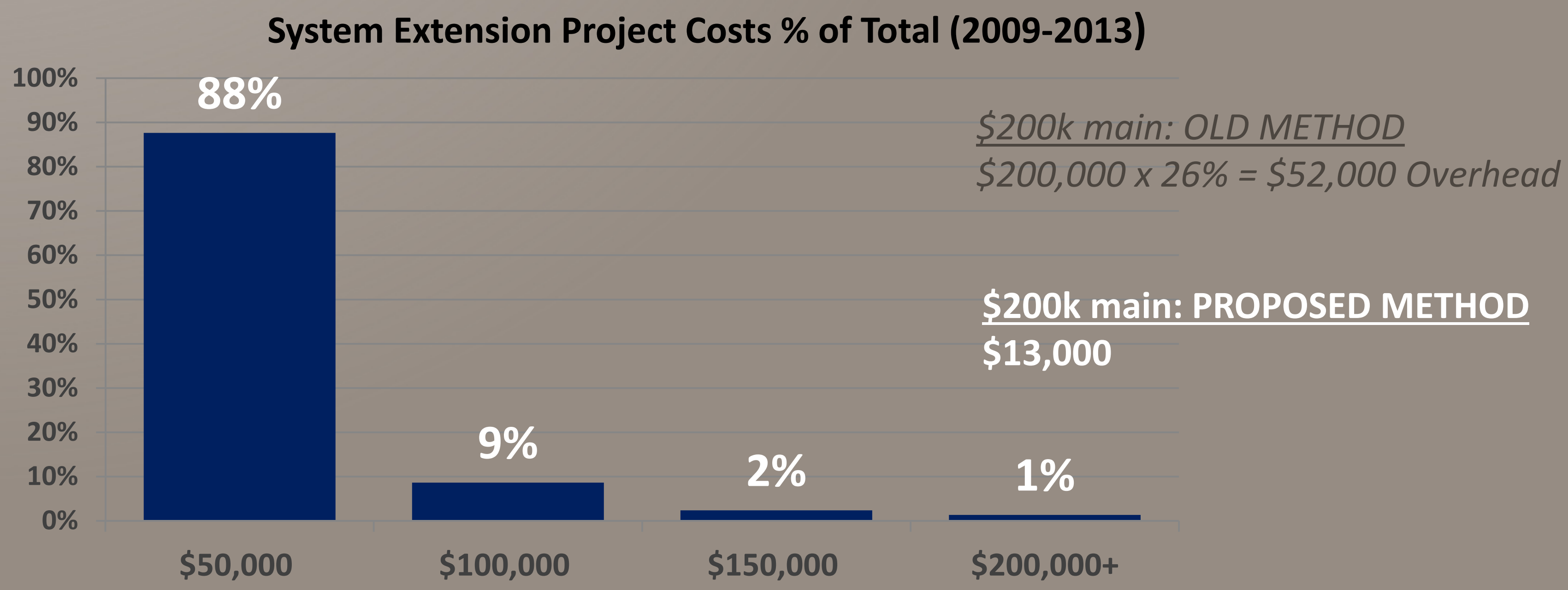
Appliances

MX Parameter	New Appliance Credits	Rationale
Appliances	**2012 REUS**	Provide FEU appliance specific credit to customers



Overhead

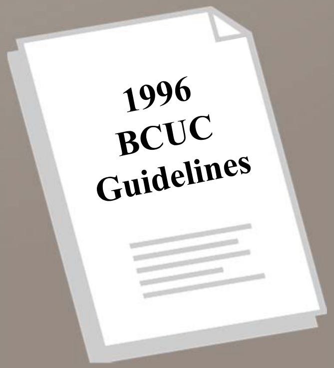
MX Parameter	New Overhead Structure	Rationale
Overhead	**1st $50k = 26% of total cost** **$50k+ = 26% on first 50k**	Reasonable overhead costs for larger main extensions



Financing

MX Parameter	New Financing Option	Rationale
CIAC (Contribution In Aid of Construction)	**Equal Payment Plan**	Provide financial assistance for contributions in aid of construction (CIAC's)

- **Spread evenly over 24 months**
- **Applies to homeowners and small commercial customers only**



The Commission recommends that the Utilities provide financing alternatives, such as contributions through customer bills…

Uneconomic Customers

MX Parameter	Uneconomic Fund	Rationale
CIAC (Contribution in Aid of Construction)	**$1.5 million**	Provide financial assistance for contributions in aid of construction (CIAC's)

- **Similar to BC Hydro's uneconomic fund**
- **Applies to homeowners and small commercial customers**
- **For main extension and service line customers only**

Summary

Proposed Change	Guiding Principles
❑ Project Life ❑ Overhead	✓ Reduce Barriers to Connect ✓ Energy Choice ✓ Domestic Use ✓ First Nations & Community Interests
❑ Attachment Window	✓ Energy Choice ✓ First Nations & Community Interests
❑ Appliances & Energy Efficiency	✓ Protect Existing Ratepayers ✓ Meet Government Policy Objectives ✓ First Nations & Community Interests
❑ Financing & Uneconomic Customer Fund	✓ Reduce Barriers to Connect ✓ Energy Choice ✓ First Nations & Community Interests

Unchanged Parameters and Practices

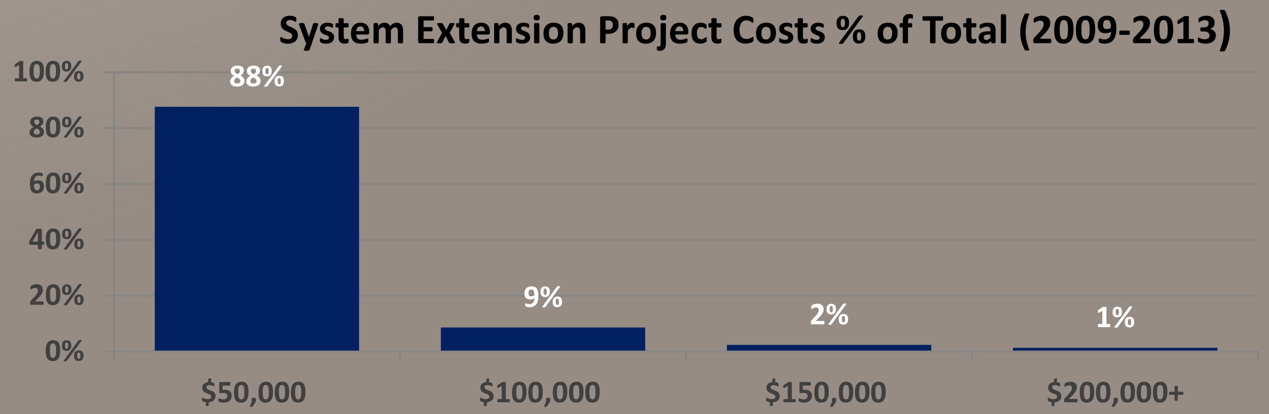
Other System Extension Test Parameters

MX Parameter	Explanation
Rates	Rates will continue to be updated on an annual basis
Operations and Maintenance Costs	The incremental costs associated with adding a new customer
Taxes	Includes income taxes, property taxes and municipal taxes
SI Charges	Represents the cost for general distribution system upgrades as a result of adding new customers.
Discount Rate	Reflects capital structure and borrowing costs for Fortis.
Mains and Service Costs	The cost for infrastructure in the street and to the building

Security

Policy	Explanation
Security	Fortis will continue with current policies surrounding security on new main extensions.

Project Type	Control	Mechanism
Large Commercial and Industrial Customers	Customer Commitment	Take or Pay Agreement
Large Main Extensions	Executive Oversight	VP and CEO sign-off
Medium to Small Main Extensions	Managerial Oversight	Senior Manager Sign Off

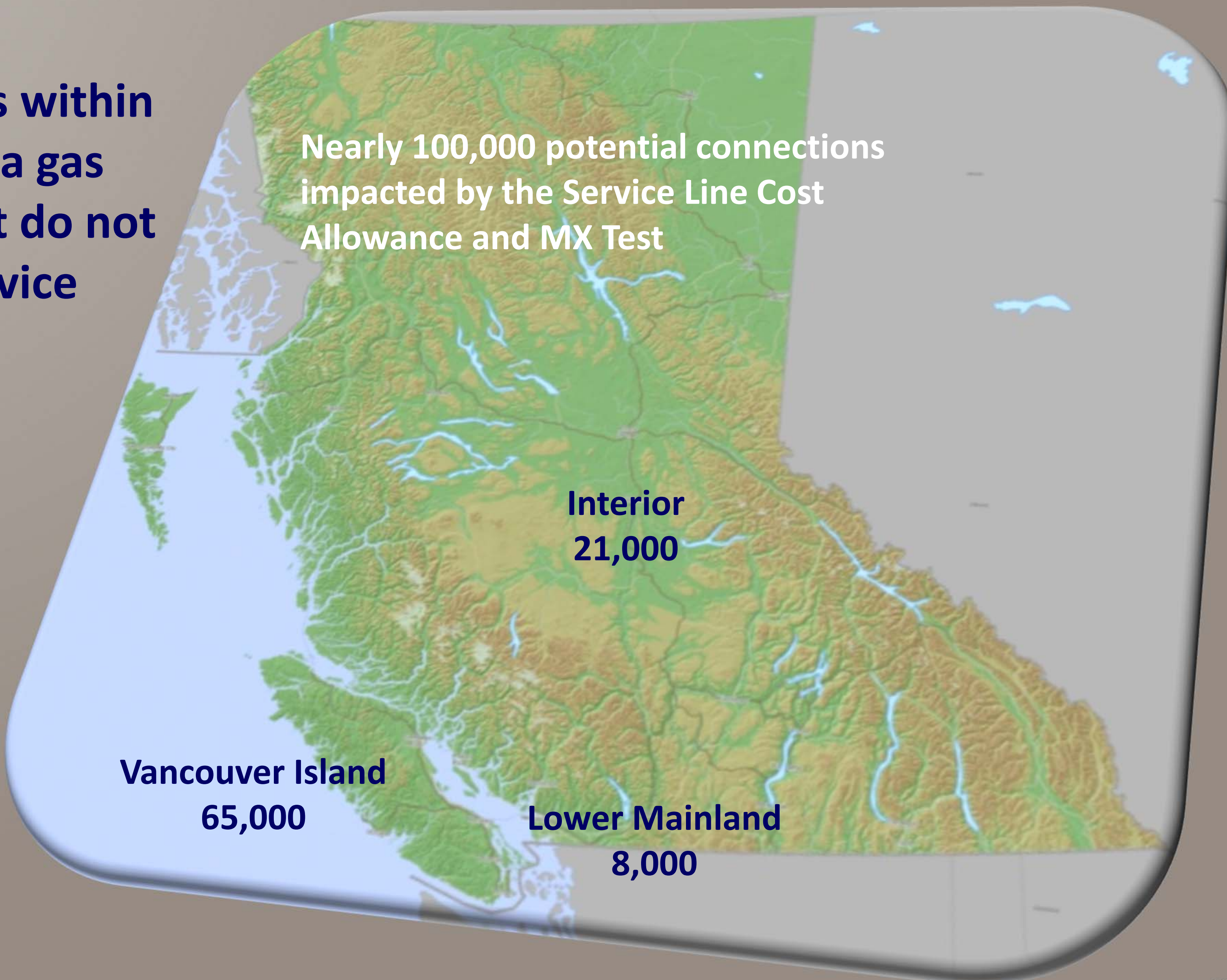


New Customer Connections:

Service Line Cost Allowance

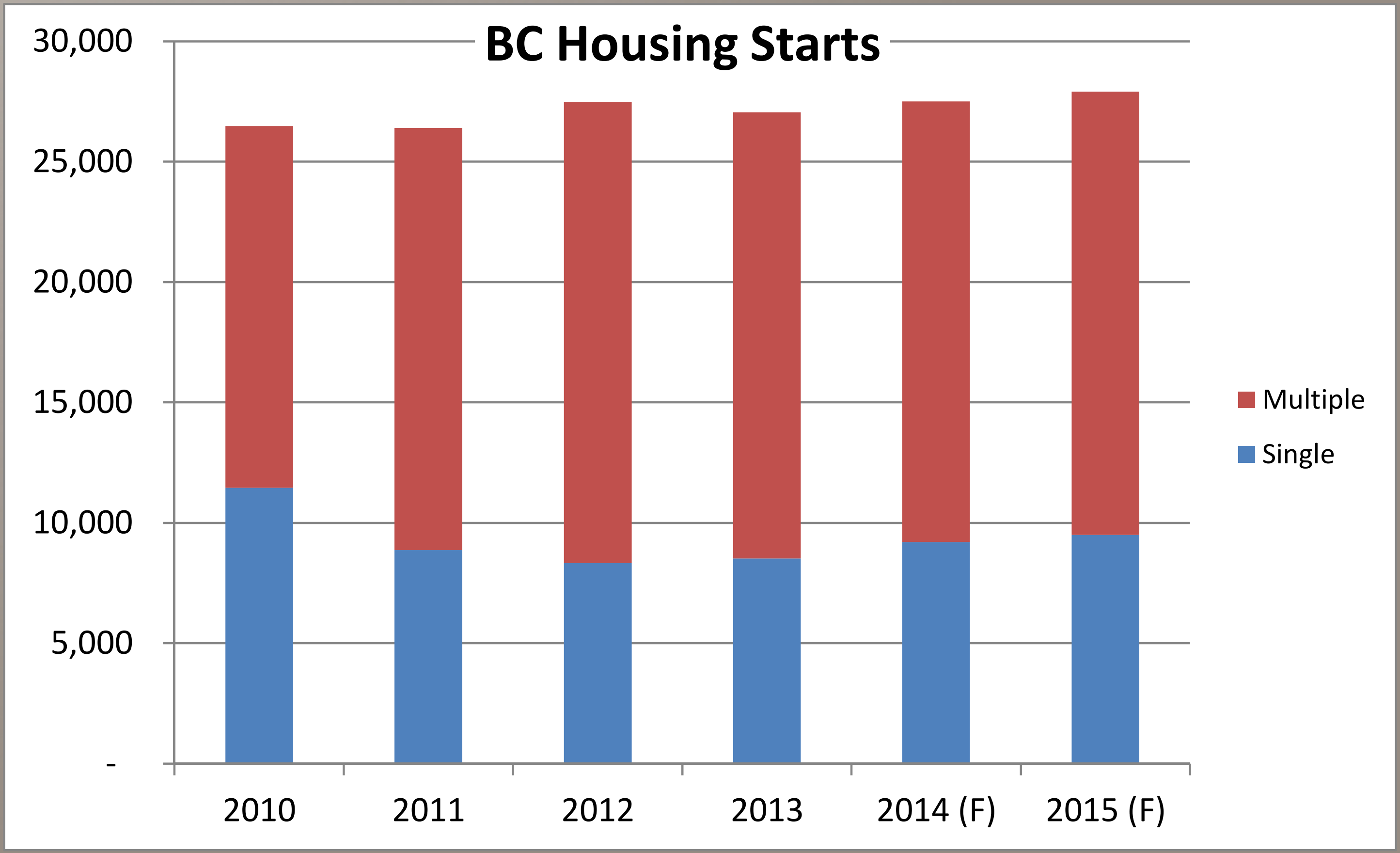
Infill & System Extension Customer Potential

- **Premises within 50 m of a gas main but do not have service**



New Construction Opportunities

25,000+ Housing Starts Annually



Source: CMHC Housing Market Outlook BC Region Highlights. Released Third Quarter 2014

Service Line Cost Allowance Methodology (2007)

1

$620

Average Main Cost

80 GJ's*

Average Consumption

Break Even

(PI 1.0)

What is the Average Service Cost?

$1,161

This is our target

System Extension Test

2

Potential SLCA Credit ($) ? $1,535

Customers	Actual Cost	Customer Contribution Based on Potential SLCA?	Customer Contribution Amount ($)
1	*$2,765*	*YES*	*$1230*
2	*$654*	*NO*	
3	*$920*	*NO*	
4	*$2405*	*YES*	*$870*
	$6,744		***$2,100***

Total Cost: $6,744

($2,100)

Less Customer Contributions: $4,644

$4,644 ÷ 4 Customers

Average cost to FortisBC is: $1,161

This matches our target based on $1,535 SLCA

Service Line Cost Allowance 2007 Results

	Consumption	Project Life (Years)	Target Service Cost	SLCA Amount/ Customer	% Customers Making A Contribution
FEI	97	20	$1,181	-	0%
	90	20	$1,064	$2,925	8%
	80	20	$910	$1,535	19%
FEVI	66	20	$1,250	$2,133	21%
	61	20	$1,093	$1,535	36%
	60	20	$1,072	$1,473	35%

** 2007 methodology where commercial is treated the same as residential*

Service Line Cost Allowance 2014 Results

	Consumption	Project Life (Years)	Target Service Cost	SLCA Amount/ Customer	% Customers Making A Contribution
	86	20	$1,944	$7,805	1%
	86	30	$2,524		0%
	86	40	$2,872		0%
	71	20	$1,576	$2,766	23%
FEU	71	30	$2,073		0%
	71	40	$2,371		0%
	67	20	$1,476	$2,375	28%
	67	30	$1,950	$8,346	1%
	67	40	$2,234		0%

** Based on 2007 methodology where commercial is treated the same as residential*

Summary

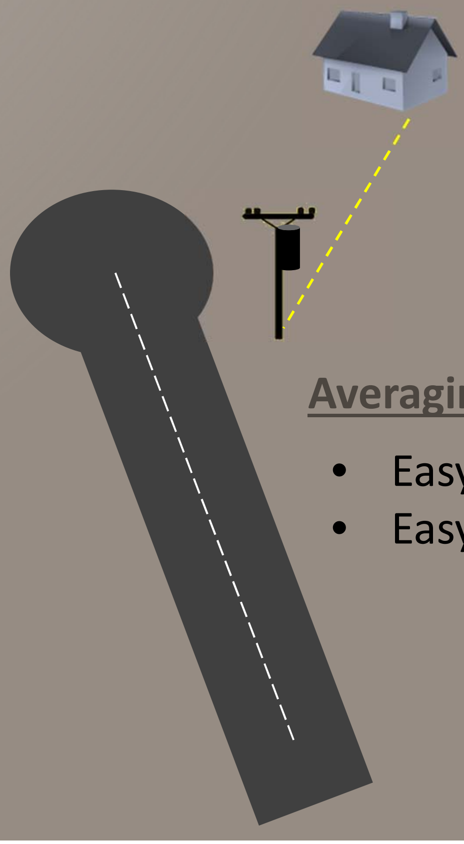
Proposed Change	Guiding Principles
❑ Update SLCA	✓ Reduce Barriers to Connect ✓ Provide an Energy Choice ✓ First Nations and Community Interests ✓ Domestic Use ✓ Meet Government Policy Objectives (Economic Improvement)

Customer Connection Options

	Customer Type	Revenue Mechanism	Utility
1	Main Extension Customers	Credit System	FORTIS BC
	Service Customers	Average Cost Allowance	
2	Equal treatment for all customers	Average Cost Allowance	BC hydro FORTIS BC
3	Equal Treatment for all customers	Credit System	Southern California Gas Company

Customer Connection Options

	Customer Type	Revenue Mechanism	Utility
2	Equal treatment for all customers	Average Cost Allowance	BC hydro FORTIS BC



Electricity Usage

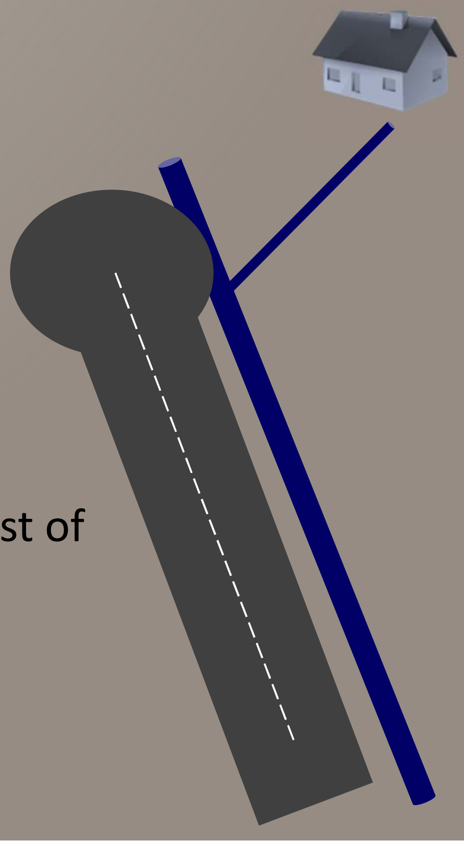
- Many household uses
- Individual/family usage patterns

Averaging for all customers makes sense

- Easy to administer and update
- Easy to understand

Customer Connection Options

	Customer Type	Revenue Mechanism	Utility
3	Equal treatment for all customers	Credit System	Southern California Gas Company®



Natural Gas

- Appliance specific credits
- $ credit applied against total cost of main or service

New Customer Connections:

Off System Communities & First Nations

Off System Communities and First Nations

- **Total Population, 2011 Census**

- **Over 180 Communities:**
  - **First Nations: 5,000**
  - **Fortis BC: 80,000**
  - **Spectra: 7,000**

Off System Communities & First Nations

- ❑ Fortis is looking for input regarding ways to provide service to these stakeholders
- ❑ Concept of a program to help off system and First Nations communities connect to our system
- ❑ Need to explore criteria

Conceptual Framework

Average Annual Mains and Services Spending (2008-2013): $23 Million	Base Case (amalgamation)	Low Case (reduced consumption)
Annual Savings for Existing Customers at Current Expenditure Level	$26	$15
Scenario #1 Capital Spending Increase	$100 Million	$50 Million
Annual Savings for Existing Customers at New Expenditure Level	$14	$7.50
Scenario #2 Capital Spending Increase	$200 Million	$100 Million
Annual Savings for Existing Customers at New Expenditure Level	$0	$0

- Potential for up to $100-$200 million

Structure:

☑ Lowest cost to serve
☑ Neutral rate payer impact
☐ Define community criteria

Off System Communities

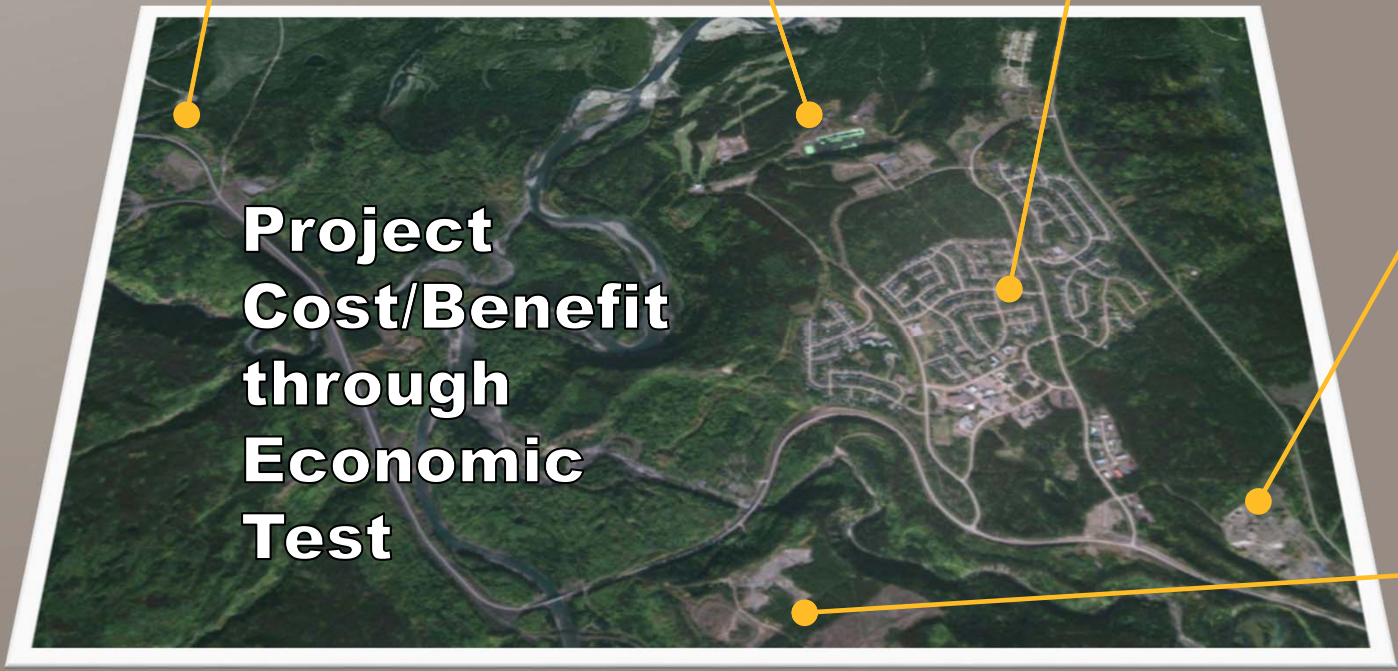
Off-System Communities in Proximity to FortisBC

Population more than	1,000	people
Population Density at least	150	people/km^2
Distance Less Than	20	km

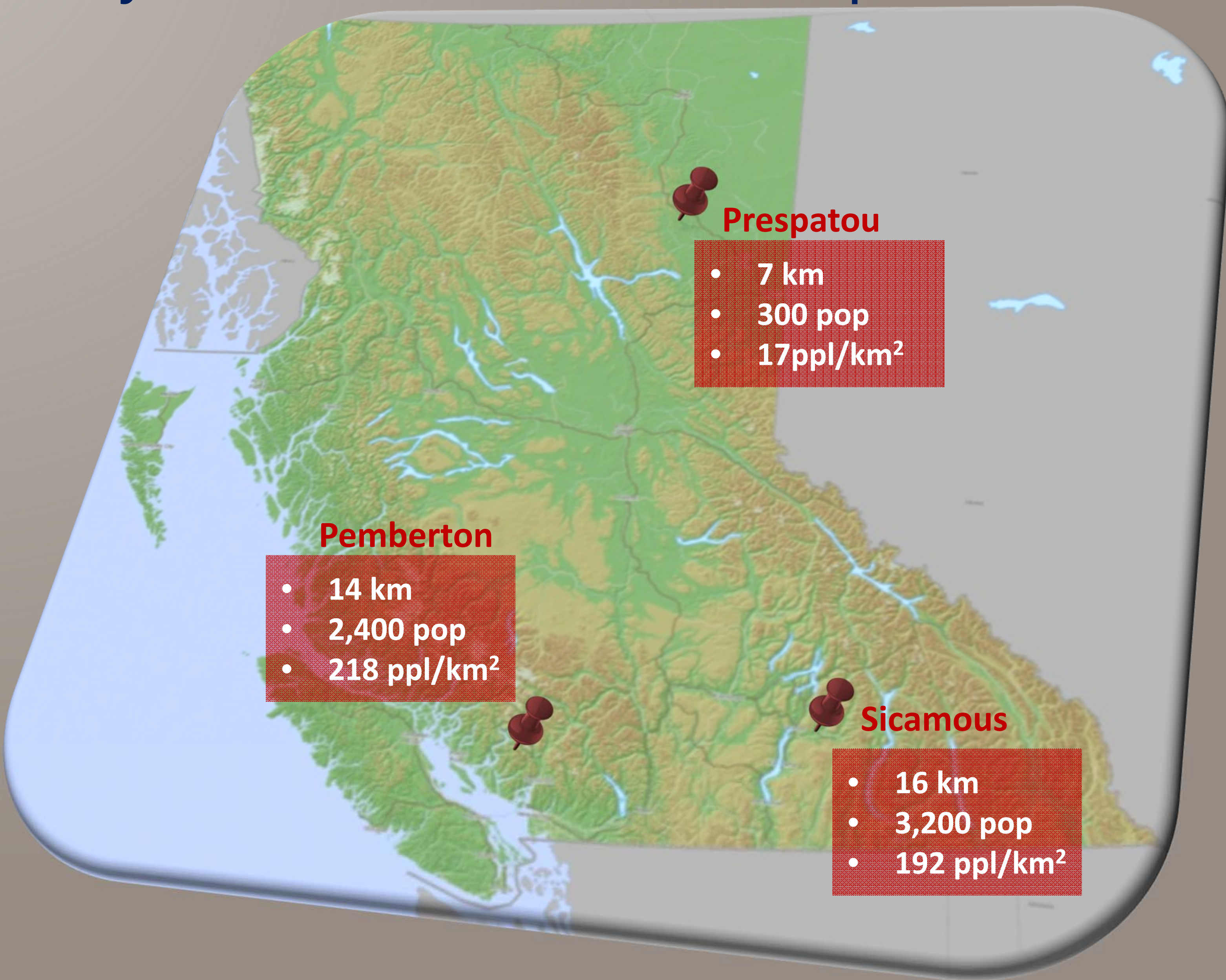
Distribution or Transmission Pressure	DP
First Nations Only	No

Name	Service Area	Pressure	Distance	Population	Population Density
Lake Cowichan	FortisBC	DP	19	2974	370
Lions Bay	FortisBC	DP	8	1318	520
Miller's Landing	FortisBC	DP	2	1113	710
Pemberton	FortisBC	DP	14	2369	218
Sicamous	FortisBC	DP	16	3166	192

Off System Communities & First Nations



Off System Communities Examples



Off System Communities & First Nations

- ❑ Create program to serve these stakeholders
  - Lowest cost to serve
  - Neutral rate payer impact

- ❑ Off-system communities apply for funding

- ❑ Select project(s) to fund each year based on criteria guidelines. E.g.
  - First Nations, benefits to downstream, economic development potential, population & density, environmental benefits

Summary

Proposed Change	Guiding Principles
❑ Further Explore Off System Community Program. Structure TBD	✓ Domestic Use ✓ Meet Government Policy Objectives (Economy and GHGs*) ✓ Provide an Energy Choice ✓ First Nations & Community Interests

Performance & Reporting

Current Performance: Reporting

Assumes entire area disappears in 20 years

Inappropriately compares actual consumption to forecasted credit

Assumes these homes will never be built or occupied

Doesn't consider anything past 5 years

Current Performance: 2008 Re-Forecast

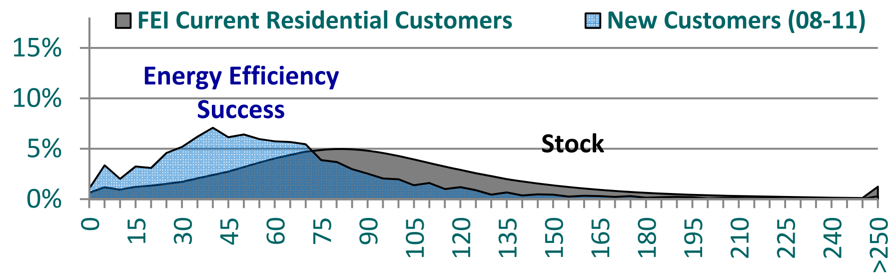
Letter L-34-14

Table 150: 2008 FEI Aggregate Main Extensions Profitability Index

2008 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.60	0.54	-66%
Years 1-5 Total	1.60	0.54	-66%

Further Details

- **9% over on Costs**
- **73% of attachments by October 2012 (417/571)**
- **Why is the PI so low?**



- **Consumption…new customer VS old**
- **Assumes many attachments will never happen**

Current Performance: More Re-Forecasts

Scenario	Assumptions	Reforecast PI Result
Re-forecast #1 (2008 Report)	• No attachments after 5 years • No attachments unless they occur in the forecast year • ½ asset life • Actual consumption VS forecast credit	.54
Re-forecast #2	• Actual attachments to date	.70
Re-forecast #3	• Actual attachments to date • Today's Rates	.90
Re-forecast #4	• Actual attachments to date • Today's Rates • Full life of project	1.26
Re-forecast #5	• Actual attachments to date • Today's Rates • Full life of project • Consumption Credits	1.57

Current Performance

- **Current reporting is just a re-forecast**
- **The performance is whatever the assumptions make it**

Current System Extension Report	
Number of Attachments	✗
Rate Payer Impacts	✗
Economic Performance of a Project	✗
Consumption Versus Forecast	✗

Value of Reporting	?
What are we trying to measure	?

Summary & Next Steps

Policy Changes Summary: Customer Connections

Customer Group	Proposed Changes	Applicable Stakeholder Guiding Principles
System Extension Customers	• Project Life • Forecast Window • Appliance Updates • Energy Efficiency • Overhead	✓ Reduce Barriers to Connect ✓ Energy Choice ✓ Meet Government Policy Objectives
Infill Customers	• Revised Service Line Cost Allowance	✓ Protect Existing Ratepayers ✓ Reduce Barriers to Connect
Uneconomic Customers	• CIAC Financing • Uneconomic Fund	✓ Reduce Barriers to Connect
Off System Communities	• Conceptual Framework for a dedicated fund with criteria (TBD) • System Extension Test Changes • CIAC Financing	✓ Reduce Barriers to Connect ✓ First Nations and Community Interests ✓ Domestic Use
All	• Reporting at time of any future system extension applications	✓ Protect Existing Ratepayers ✓ Easy to Understand

Next Steps

- **Stakeholder Feedback**
- **Workshop #4 – Mid November**
- **Letters of Support**
- **Workshop #5 – prescreen application (early March)**
- **Application Q1 2015**

Stakeholder Package following June 18, 2014 Workshop

This letter provides a summary of the discussions to date regarding the stakeholder based review of FortisBC's system extension policies (the "Project"). It is organized into the following sections:

- Part 1: Request of Stakeholders outlines the request for comments from stakeholders
- Part 2: Background provides a brief history of the Project
- Part 3: Terms of Reference outlines the Project purpose, process, roles and responsibilities, scope and timeline
- Part 4: Guiding Principles outlines the relevant regulatory history along with a summary of the stakeholder feedback in this area
- Appendix contains a list of participants attending the two workshops

PART 1: Request of Stakeholders

On June 18, 2014, FortisBC held its second system extension review workshop with stakeholders. As agreed in the workshop, FortisBC has summarized the feedback from stakeholders and is requesting comments before finalizing the terms of reference and guiding principles. This document will then be used to determine the nature of the analysis to be completed in advance of our third stakeholder workshop, tentatively scheduled for October 2014.

Please provide any comments on the document, especially the terms of reference and guiding principles, to mike.metza@fortisbc.com by July 4, 2014.

PART 2: Background

In the fourth quarter of 2013, FortisBC met individually with prospective stakeholders. Preliminary support was established for conducting a review of FortisBC's system extension policies in a consultative manner. Stakeholders identified their time constraints and requests were made to schedule the review starting February 2014.

On February 18, 2014 FortisBC held an initial system extension stakeholder workshop. The primary focus of the workhop was to provide stakeholders with a general understanding of current system extension policies and their role in connecting new customers to FortisBC's natural gas distribution system. Throughout the workshop, participants heard from several Stakeholders who spoke to a range of issues such as the different types of new gas customers and their unique and sometimes contrasting needs when it comes to making an efficient energy choice, the challenges faced by off-system communities in meeting their specific energy needs, and a comparison and discussion of the system extension policies of other utilities in Canada and the Pacific Northwest.

A key finding from the workshop was a general consensus among stakeholders that there are gaps in FortisBC's system extension policies in terms of addressing the needs of the different types of customers. Another key finding was the support of a consultative, efficient process for the review of a potential, future application. FortisBC and other stakeholders, including CEC and PIAC, reported how the process followed in 2011 for FortisBC's Gas Supply Incentive and Mitigation Program ("GSMIP") was effective and could serve as a model for engaging stakeholders and pursuing an application with the British Columbia Utility Commission (Commission). In light of these findings, participants agreed to continue with a consultative review of the Company's system extension policies resembling the GSMIP process.

On June 18, 2014, FortisBC held a second system extension stakeholder workshop. Prior to this meeting, FortisBC sent a stakeholder package for comments to help guide the discussion. The purpose of this meeting was to summarize the first workshop, review the terms of reference, and discuss the guiding principles for system extension policies and the deliverables following the workshop.

A list of workshop attendees is found in Appendix A.

Throughout the second workshop, FortisBC summarized feedback it received from stakeholders in advance of the workshop and facilitated the expression of a wide variety of interests. The document that follows captures the views expressed in the second workshop.

PART 3: Project Terms of Reference

The following section outlines the terms of reference for the Project, specifically, the purpose, process, roles and responsibilities, scope and timelines.

Purpose

This Project is a stakeholder driven initiative designed to address gaps with FortisBC's current natural gas system extension policies.

Process

The Project workshops will provide a venue to educate stakeholders and solicit their feedback on FortisBC's system extension policies. Recommendations from the Project will form the foundation for a potential application from FortisBC to the Commission. By employing a stakeholder focused approach, the varied interests of stakeholders will be best represented and the Project is expected to be more efficient as a result.

As discussed above, FortisBC is trying to replicate the process used to develop the GSMIP.

Roles and Responsibilities

In the Project, there are four Project roles for participants: facilitator, consultant, stakeholder and Commission Staff.[1]

[1] IBID

Facilitator

This role will be fulfilled by FortisBC. In summary, the function of the facilitator is twofold: a) to oversee the manner in which the Project process is carried out; and b) to ensure that the full range of issues is effectively addressed. In conducting the Project, the facilitator will:

- Help to foster an environment of cooperation and trust among participants
- Ensure that all participants have an opportunity to express their views on each issue
- Facilitate the preparation of a proposed Project application which contains all the required components
- Guide the list of issues

The facilitator will attempt to perform the following functions:

- clarifying and summarizing a party's position;
- making explicit any differences in the positions taken by the respective parties;
- recognizing the possible concerns of unrepresented parties;
- encouraging a party to evaluate its own position in relation to other parties by introducing objective standards; and
- identifying options or approaches that have not yet been considered

In the event that FortisBC proceeds with an application to the Commission, FortisBC will be seeking letters of comment and/or support from stakeholders who attended the workshops.

Consultant

This role will be fulfilled by EES Consulting who will provide expertise in the area of system extension policies and related analysis.

Stakeholder

This role will be fulfilled by all parties other than FortisBC, EES Consulting and Commission staff (Staff). Stakeholders have a right to participate in the Project. The responsibilities of this role are as follows:

- Attend workshops and participate in all aspects of policy exploration and formulation
- Represent the views of their constituents
- Review and comment on data analysis and results as needed

Commission Staff

The responsibility of Staff is to ensure that the interests of all affected parties are taken into account. The responsibilities of Staff involved in the Project include the following:

- Supplying factual information that may otherwise not have been brought to the attention of the stakeholders
- Describing possible implications of Project proposals for unrepresented parties; and
- Advising the participants of any precedents recognized by the Commission;

Scope

Included in the Project scope generally is the Companies' current system extension policies and the development of a suitable construct (s) to attach customers, including but not limited to the following:

Customer Types	**Description of Customer Type**	**Current Regulatory Construct**	**Scope of System Extension Review***
Infill	Customers located within the Companies distribution service territory that requires a service connection to existing natural gas infrastructure already at their location.	Service line cost allowance ("SLCA")	• Identifying a construct to attach infill customers
Main extension ("MX")	Customers who are within a local proximity to the Company's current distribution system and require a main extension to their location before a service connection can be provided.	MX test	• Identifying a construct to attach main extension customers
Off system communities, including First Nations	Customers who require, but do not currently have any natural gas distribution infrastructure within their community.	Certificate of Public Convenience and Necessity ("CPCN")	• Identifying a construct to attach off-system

*Commonalities in the scope of the review across different customer types are as follows:

Time horizon

- Time horizon of any economic test developed
- Forecasting period for new customer attachments

Rate Class

- Treatment of individual customer classes based on rates

Uneconomic Customers

- Contribution in aid of construction ("CIAC") financing
- Contributory thresholds
- Security

Reporting

- Best practices of other peer utilities
- Review of FortisBC's current reporting practices & performance results
- After the attachment model is agreed upon, recommend reporting construct if required.

Timeline

The Project timeline is summarized in the table below:

Date	Event	Topic	Goal	Status
Q4 2013	Individual Stakeholder Consultation	Initial Consultation	Garner Stakeholder support to begin review process.	Complete
February 18, 2014	FortisBC System Extension Stakeholder Workshop #1	Policy Issues	Introduction to current issues and agreement to proceed with exploration of policy alternatives.	Complete
June 18, 2014	FortisBC System Extension Stakeholder Workshop #2	Review of Workshop 1, Terms of Reference & Guiding Principles	Stakeholder feedback on guiding principles will be used to form the foundation of policy options.	Complete
October 2014	FortisBC System Extension Stakeholder Workshop #3	Options Discussion	Review system extension options as developed by Fortis and Stakeholders and opportunity for questions and changes.	TBD
November 2014	FortisBC System Extension Stakeholder Workshop #4	Options Discussion	Continuation of Workshop 3 (as needed)	TBD
Q1 2015	Potential	Potential	Consideration of	TBD

	Application	Application	potential application to Commission	

PART 3: Guiding Principles

This section is intended to form the initial policy foundation for any future system extension policy enhancements to be considered in the Project. It is organized into three sections covering the following:

- The background on relevant guiding principles from historical Commission proceedings
- The change in market conditions since the most recent Commission proceedings
- Summary of stakeholder feedback on guiding principles

Background

1996 Utility System Extension Test Guidelines

This following list briefly summarizes some of the voluntary guidelines[2] that were developed and issued by the Commission under order G-80-96[3] following a hearing and reconsideration decision on Utility System Extension Tests during the late 1990's.

- Evaluation of system extension should include all benefits and costs over a time period long enough to consider the full impact of the extension.
- System extensions should be evaluated from a social perspective and a utility perspective.
- System extension costs should include pre-construction estimates of the construction costs, system improvement costs, O&M costs, revenues and a reasonable consideration of externalities (for the social perspective evaluation.)
- Utilities should come forward with options for connection fees that send an appropriate signal about the net social costs of less efficient energy use.

2007 Terasen Utilities System Extension and Customer Connection Policies Review Application[4]

The items below highlight some of the key considerations Terasen (now FortisBC) put forward as the basis for the modifications requested in the application. The Companies stated that system extension policies should:

- Signal better value for customers wishing to attach to the system.
- Measure the right factors, be simple to understand and administer with results that send the appropriate economic signal to the customer.
- Encourage energy conservation through the test and attachment policies
- Encourage the "right fuel" choice. The Companies believe that natural gas is the appropriate fuel for space and water heating applications and that the connection policies and tests should send the appropriate signal to customers for these energy choices.

---

[2] 1996 Utility System Extension Test Guidelines – September 5, 1996

[3] British Columbia Utilities Commission Order G-80-96 – August 9, 1996

[4] Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. System Extension and Customer Connection Policies Review Application - July 31, 2007

The Companies' proposed modifications to its system extension policies were approved under Commission Order G-152-07[5].

Bonbright Principles

The following list of principles has been developed by FortisBC by incorporating system extension issues in the context of the Principles of Public Utility Rates, developed by James C. Bonbright. (Bonbright Principles). Bonbright Principles have been referred to in various applications by the Companies and other utilities. As such, they help by providing a framework for discussing future system extension policy considerations.

- Customer Impact: Considers customer rate impacts of system extensions.
- Fairness: Ensure fairness between customers in terms of both cost causation and similar treatment over time, recognizing the changes in housing environment, technology and natural gas usage patterns of new and existing customers. Also recognizes the need for fair access for "off-system" communities who require natural gas service.
- Economic Efficiency: Recognizes energy efficiency and conservation at the time of construction for new connections and in the trade-off between main extension policies and rate impacts.
- Stability: Reflects long-term objectives that will not lead to frequent changes so that customers know what to expect over time.
- Ease of Understandability: Allows customers to understand the policies and therefore be able to make appropriate choices, as well as making policies easy to administer.
- Competitiveness: Allows for competitiveness of the utility to attract new customers relative to competing gas utilities as well as competing alternative fuels.
- Recovering the Cost of Service: Allows for recovery of utility costs.

Changing Market Conditions

The marketplace has undergone several significant changes since the mid-1990s when system guidelines were developed. These changes and the resulting policy considerations follow.

[5] British Columbia Utilities Commission Order G-152-07 – December 6, 2007

Natural Gas Supply

Since the time of the development of the original utility system extension guidelines by the Commission in 1996, and a review of system extension policies in 2007, the BC natural gas industry as a whole has undergone substantial change. Supply outlooks reversed from an imminent dwindling of supplies and a scramble to find and import LNG, to today, where BC has now become a leading exporter of natural gas to Canada, the US and global markets with supplies forecast beyond the next 100 years[6]. Prices have gone from a high and volatile to a low and relatively stable environment.

Provincial Government Objectives

During the second workshop, two provincial government objectives were identified:

1. *Environmental considerations related to the Greenhouse Gas Reduction Target Act and the Clean Energy Act*
2. *Economic considerations related to the province's natural gas strategy*

Stakeholders identified challenges in accommodating both objectives in the context of a review of FortisBC's system extension policies. Promoting the most efficient use of natural gas was brought forward as a potential common ground for the two government objectives.

Amalgamation & Rate Design

Stakeholders identified the importance of acknowledging FortisBC moving to a "postage stamp" rate in 2015 and a potential rate design proceeding in 2016. FortisBC indicated that it hoped to proceed with a potential application related to the Project before rate design proceeding occurs.

Guiding Principles

In the second workshop, stakeholders discussed the need for tradeoffs when considering guiding principles as some principles are complimentary while others are contradictory. The following section summarizes the feedback received during the workshop into several main categories.

Protecting Ratepayers

- Relevant benefits, costs and rate impacts of system extension policies should be considered as they relate to new and existing customers

Provide an Energy Choice

- System extension policies need to consider the need for BC residents to fairly and equitably access a variety of energy options.

Consistency with Government Objectives

- System extension policies relating to the domestic use of natural gas need to be consistent with the provincial government's natural gas strategy
- The provincial government's environmental and economic objectives also need to be considered

[6] Spectra Energy presentation at PNUCC Power and Natural Gas Planning Taskforce meeting April 11, 2014

Recognize First Nations

- The needs of First Nations communities should be recognized

Easy to Understand

The system extension policies need to be easily understood, easy to administer by FortisBC and stable over time for customers

Appendix

Below is a list of FortisBC employees, stakeholders and Staff who participated in the first and second workshops.

Stakeholder	Attendee	Title	Attended Workshop 1	Attended Workshop 2
BC Hydro	**Justin Miedema**	Senior Regulatory Advisor, Rates and Regulatory	**Yes**	**Yes**
BC Hydro	**Kevin Lim-Kong**	Policy Specialist, Customer Interconnections & Policy	**Yes**	**n/a**
BC Hydro	**Frank Lin**	Director, Interconnections and Shared Assets	**Yes**	**n/a**
BC Hydro	**Rena Messerschmidt**	Policy Manager, Customers Interconnections & Policy	**Yes**	**n/a**
BC Chamber of Commerce	**Susan Payne**	Executive Director, Ucluelet Chamber of Commerce	**n/a**	**Yes**
BCUC - British Columbia Utilities Commission	**Kristine Bienert**	Acting Director, Policy, Planning and Customer Relations	**No**	**No**
BCUC - British Columbia Utilities Commission	**J Todd Smith**	Acting Director, Infrastructure	**No**	**No**
BCUC - British Columbia Utilities Commission	**Suzanne Sue**	Senior Regulatory Specialist	**Yes**	**Yes**
BCUC - British Columbia Utilities Commission	**Chris Garand**	Engineer, Infrastructure	**Yes**	**Yes**
Chawathil First Nation	**Norman Florence**	Council Member	**n/a**	**Yes**
CEC - Commercial Energy Consumers	**David Craig**	President, Consolidated Management Consultants	**Yes**	**Yes**
EES	**Gail Tabone**	Senior Consultant, EES Consulting	**Yes**	**Yes**
Fortis BC	**Mike Metza**	Energy Products & Services	**Yes**	**Yes**

		Manager		
Fortis BC	**Brent Graham**	Manager, Energy Products & Services	**Yes**	**Yes**
Fortis BC	**Jason Wolfe**	Director, Market Development	**Yes**	**Yes**
Fortis BC	**Dennis Swanson**	Director, Regulatory Affairs	**Yes**	**Yes**
Fortis BC	**Vanessa Connolly**	Government Relations and Public Affairs Manager	**n/a**	**Yes**
Fortis BC	**John Turner**	Director, Energy Solutions	**Yes**	**n/a**
Fraser Valley Regional District	**Lloyd Foreman**	Director, Electoral Area A	**n/a**	**Yes**
Fraser Valley Regional District	**Dennis Adamson**	Director, Electoral Area B	**n/a**	**Yes**
MEM - Ministry of Energy and Mines	**Katherine Muncaster**	Acting Director, Energy Efficiency Branch	**Yes**	**Yes**
MJT - Ministry of Jobs, Tourism and Skills Training	**Robert Wood**	Acting Director, Major Investments Office	**n/a**	**Yes**
MLA Boundary - Similkameen	**Colleen Misner**	Constituency Assistant to Linda Larson, MLA	**Yes**	**No (illness)**
Okanagan - Similkameen Regional District	**George Bush**	Board Member	**Yes**	**Yes**
PRRD - Peace River Regional District	**Karen Goodings**	Board Director	**Yes**	**Yes**
PIAC - Public Interest Advocacy Centre	**Tannis Braithwaite**	Executive Director	**Yes**	**Yes**
PNG - Pacific Northern Gas	**Janet Kennedy**	Vice President, Regulatory Affairs and Gas Supply	**Yes**	**Yes**
PNG - Pacific Northern Gas	**Peter Schriber**	Manager, Financial Planning & Business Development	**Yes**	**Yes**
Seabird Island Band	**Brian Titus**	Consultant	**n/a**	**Yes**
Seabird Island Band	**Chief Clem Seymour**	Chief	**n/a**	**Yes**
Yale First Nation	**Steven Patterson**	Natural Resource Manager	**n/a**	**Yes**

FORTIS BC

System Extension Stakeholder Workshop #4

Event Details:

Date:	Monday December 8th, 2014
Time:	7:00 AM – 12:30 PM
Location:	Conway Room (6th Fl.) - The Shangri-La Hotel 1128 West Georgia Street Vancouver, BC V6E 0A8 604-689-1125 http://www.shangri-la.com/vancouver/

Contact: Mike Metza
Energy Products & Services Manager
Tel: 604-592-7852
Cell: 604-790-5334
Fax: 604-592-7620
mike.metza@fortisbc.com

Agenda:

Time	*Topic*	*Details*	*Presenter*
7:00-7:45	**Registration – Breakfast Provided**		
	Introduction	• Meeting Objectives • Summary of Workshop Process	Jason Wolfe – Fortis BC
	Updated Rate Impact Analysis	• Review Scenarios & Revisions • Confirm Results	Gail Tabone – EES Consulting
	System Extension Policy Changes	• Confirm proposed changes: i. System Extension Test ii. Service Line Cost Allowance iii. CIAC Financing	Mike Metza – Fortis BC
10:15-10:30	**Break**		
	Uneconomic Fund	• Program Structure and Criteria • Rate Impact	Brent Graham – FortisBC
	Off System Communities	• Multi-Tier Assessment Test (MAT) • Contribution Framework	Brent Graham – FortisBC
	Closing	• Confirm Next Steps	Brent Graham – FortisBC
12:30	**End**		

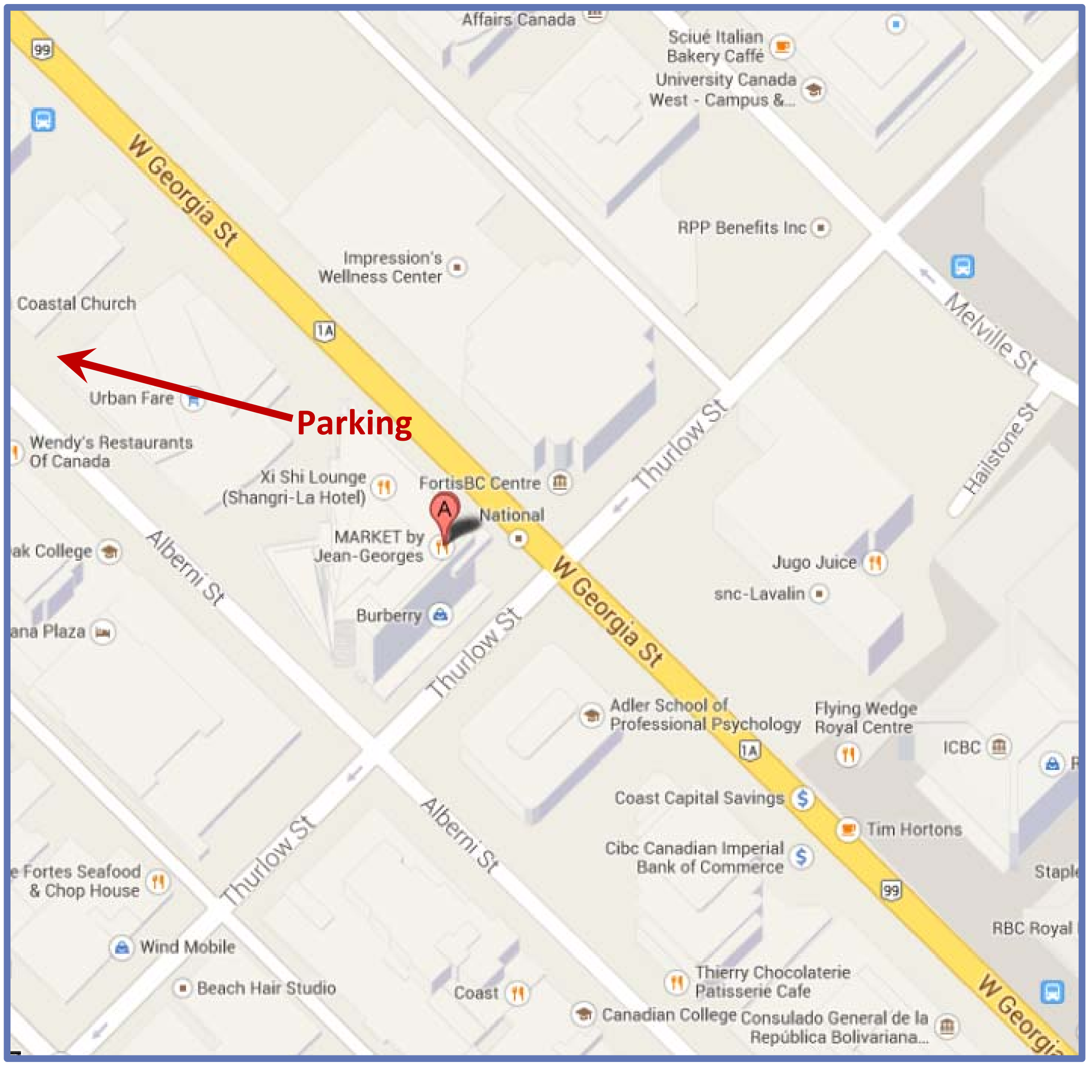
Special Notes:

- There is a valet parking at the hotel and vouchers will be given out at the registration table. Please have your parking stub with you.
- Coffee and beverages will be provided throughout the morning.

List of Confirmed Attendees:

Name	Title	Stakeholder
Justin Miedema	Senior Regulatory Advisor, Rates and Regulatory	BC Hydro
Kevin Lim-Kong	Policy Specialist, Customer Interconnections & Policy	BC Hydro
Frank Lin	Director, Interconnections and Shared Assets	BC Hydro
Rena Messerschmidt	Policy Manager, Customers Interconnections & Policy	BC Hydro
Katherine Muncaster	Acting Director, Energy Efficiency Branch	BC Ministry of Energy and Mines
Rob Wood	Acting Director, Major Investments Office	BC Ministry of Jobs Tourism and Skills Training
William J Andrews	William J. Andrews, Barrister & Solicitor	B.C. Sustainable Energy Association & Sierra Club B.C.
Thomas Hackney	Case Manager	B.C. Sustainable Energy Association & Sierra Club B.C.
Suzanne Sue	Senior Regulatory Specialist	BC Utilities Commission
Chris Garand	Engineer, Infrastructure	BC Utilities Commission
J Todd Smith	Acting Director, Infrastructure	BC Utilities Commission
Bobbi Ellen Peters	Band Council Member	Chawathil First Nation
David Craig	President, Consolidated Management Consultants	Commercial Energy Consumers BC
Gail Tabone	Senior Consultant, EES Consulting	EES Consulting Ltd.
Mike Metza	Energy Products & Services Manager	Fortis BC
Brent Graham	Manager, Energy Products & Services	Fortis BC
Jason Wolfe	Director, Energy Solutions	Fortis BC
Corey Sinclair	Manager Regulatory Affairs	Fortis BC
Howard Mak	Regulatory Policy Manager	Fortis BC
Vanessa Connolly	Government Relations and Public Affairs Manager	Fortis BC
Dennis Adamson	Director, Electoral Area B	Fraser Valley Regional District
Lloyd Forman	Director, Electoral Area A	Fraser Valley Regional District
Colleen Misner	Constituency Assistant to Linda Larson, MLA	MLA, Boundary-Similkameen
Katrine Conroy	MLA	MLA, Kootenay West
George Bush	Board Member	Okanagan - Similkameen Regional District
Peter Schriber	Manager, Financial Planning & Business Development	Pacific Northern Gas
Karen Goodings	Board Director	Peace River Regional District
Tannis Braithwaite	Executive Director	Public Interest Advocacy Centre
Chief Clem Seymour	Seabird Island Band Chief	Seabird Island Band
Brian Titus	Seabird Island Band Consultant	Seabird Island Band
Steven Patterson	Natural Resource Manager	Yale First Nation

Maps:



Affairs Canada
Sciué Italian Bakery Caffé
University Canada West - Campus &...
W Georgia St
RPP Benefits Inc
Impression's Wellness Center
Coastal Church
Melville St
Urban Fare
Parking
Wendy's Restaurants Of Canada
Thurlow St
Hailstone St
Xi Shi Lounge (Shangri-La Hotel)
FortisBC Centre
National
MARKET by Jean-Georges
Alberni St
Jugo Juice
snc-Lavalin
Burberry
W Georgia St
Thurlow St
Adler School of Professional Psychology
Flying Wedge Royal Centre
ICBC
Coast Capital Savings
Tim Hortons
Alberni St
Thurlow St
Cibc Canadian Imperial Bank of Commerce
Fortes Seafood & Chop House
Wind Mobile
Beach Hair Studio
Coast
Thierry Chocolaterie Patisserie Cafe
Canadian College
Consulado General de la República Bolivariana...
RBC Royal

FortisBC System Extension Review Stakeholder Workshop #4

December 8, 2014

FORTIS BC™

Stakeholders:

Yale First Nation Government

Chawathil First Nation

Seabird Island Band

Regional District RDOS Okanagan-Similkameen

BC PIAC British Columbia Public Interest Advocacy Centre

Sierra Club BC

PRRD

British Columbia Utilities Commission

MLA Linda Larson Boundary-Similkameen

BC Sustainable Energy Association

British Columbia

CEC British Columbia

Fraser Valley Regional District

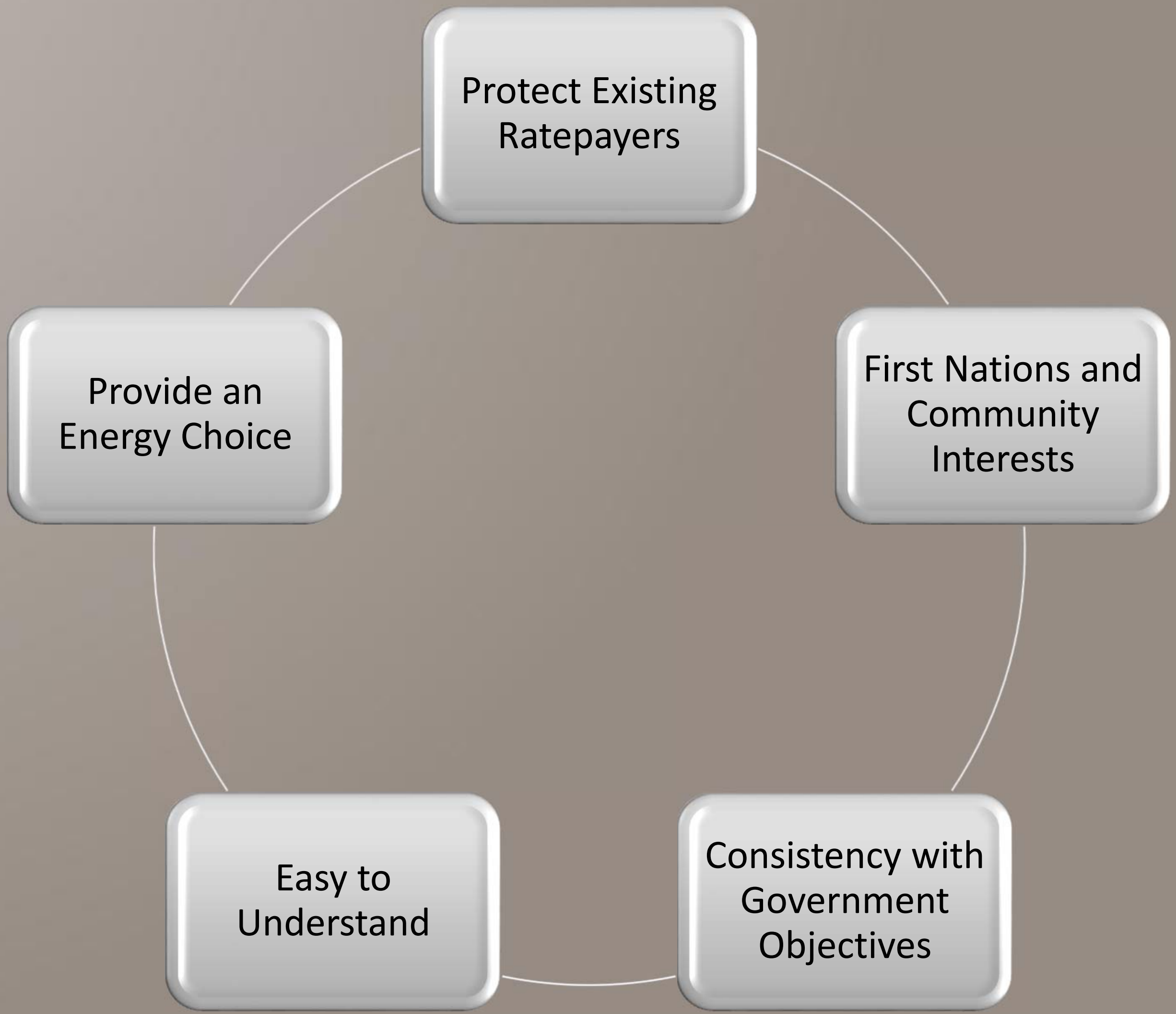
FORTIS BC

EES Consulting

PNG Pacific Northern Gas Ltd.

BC hydro

Stakeholder Guiding Principles



Stakeholder Workshop Process

Consultation

Stakeholder Education & Support

- Individual meetings with Stakeholders
- Discuss issues with new customer connections
- Communicate need for a system extension policy review

Workshop #1

Education

Policy Environment

Issues

- Various customer types
- Pricing impacts under current environment
- Feedback from customers across BC
- EES Consulting utility comparison

Workshop #2

Proposed Framework

Stakeholder Input & Principles

Project Terms of Reference

- Historic precedent and changing market conditions
- Review scope for in-fill customers, system extension customers and off-system communities
- Define guiding principles

Workshop #3

Proposed Solutions

Rate Impacts

Stakeholder Feedback

- Positive rate impacts of growth
- Update system extension test and service line cost allowance
- Review reporting and performance
- Explore uneconomic connections and off-system communities

Workshop #4

Integrate Feedback

Confirm Changes

Initiate Application

- Update solutions based on Stakeholder feedback
- Confirm proposed changes to existing policies for in-fill and system extension test customers
- Continue dialogue on policies for off-system communities

Workshop #4 Objectives:

- Review Updated Impacts of Growth Rate Impact Analysis
- Confirm System Extension Test, SLCA, CIAC Financing & Uneconomic Fund Changes
- Continue Dialogue re. Off-System Communities
- Reporting Changes
- Next Steps

FortisBC Objectives:

- Make it Easier for Customers to Attach to our System
- Encourage the Efficient Use of Natural Gas

Impacts of Growth on Customers Update

Impacts of Growth: Methodology

FEU Amalgamation Cost of Service Application "COSA"

- *$ Cost of Service*
- *$ Total Rate Base Expenses*
- *Total Amount of Gas*
- *Total FEU Customers*

Original Costs

FEU Additions to Rate Base (2008-2013) "Growth"

- *$ Total Mains*
- *$ Total Services*
- *New Customers Added*
- *New Customer Consumption*

New Customers

Impacts of Growth: Assumptions

Amalgamation Cost of Service Application Case	2013 Residential Consumption Case
Blended Residential, Commercial and Industrial Customers	
Assumes System Average for Residential Customers	Assumes New Customer Average for Residential Customers
Other Expenses and O&M increase at 50% of the rate of growth (PBR Methodology)	

Impacts of Growth: Existing & New Customers

- Existing customers have saved $12-$18 per year from capital growth (2008-2013)

- $3 / Customer / Year

- Investment in new customers could effectively double while still protecting existing customers
    - CIAC financing, uneconomic fund, off system program

Impacts of Growth: Commission Questions

1 **Why do the numbers differ from the methodology paper and actual rate impact model?**

Methodology Description Use Per Customer	Rate Impact Analysis Use Per Customer
155 GJ's (123 @ 80%) (blended Residential, Commercial & Industrial)	167 GJ's (134 @ 80%) (blended Residential, Commercial & Industrial)

Response:

- The methodology write-up had already been written and we neglected to update it with the COSA number.
- The methodology paper shows a different number than what was in the model.
- The methodology paper will be updated to reflect the correct number.

Impacts of Growth: Commission Questions

2 **Why do you blend the use rate (residential, commercial and industrial)?**

- There were no industrial customer additions from 2008-2013 (PBR Application & RRA)
- FEI has forecasted no industrial customer additions for 2024-2018 (PBR Application)

Response:

- There were industrial customer additions from 2008-2013. The table presented in the RRA and PBR shows a net amount where the account closures and abandonments have been included as well.
- It has been Fortis BC’s practice for several years not to forecast industrial customers given the substantial variability in load and difficulty in predicting attachments.
- A forecast of “0” is indicative of this practice.

System Extension Test & SLCA Changes

System Extension Test Changes

Project Life

- Current:
  20 Years

- **Update:**
  40 Years

  - *Reflect actual asset life*
  - *Consistent with other utilities*

Overhead Rate

- Current:
  26% on Total Cost

- **Update:**
  26% on First $50k

  - *More reflective of actual overhead costs*

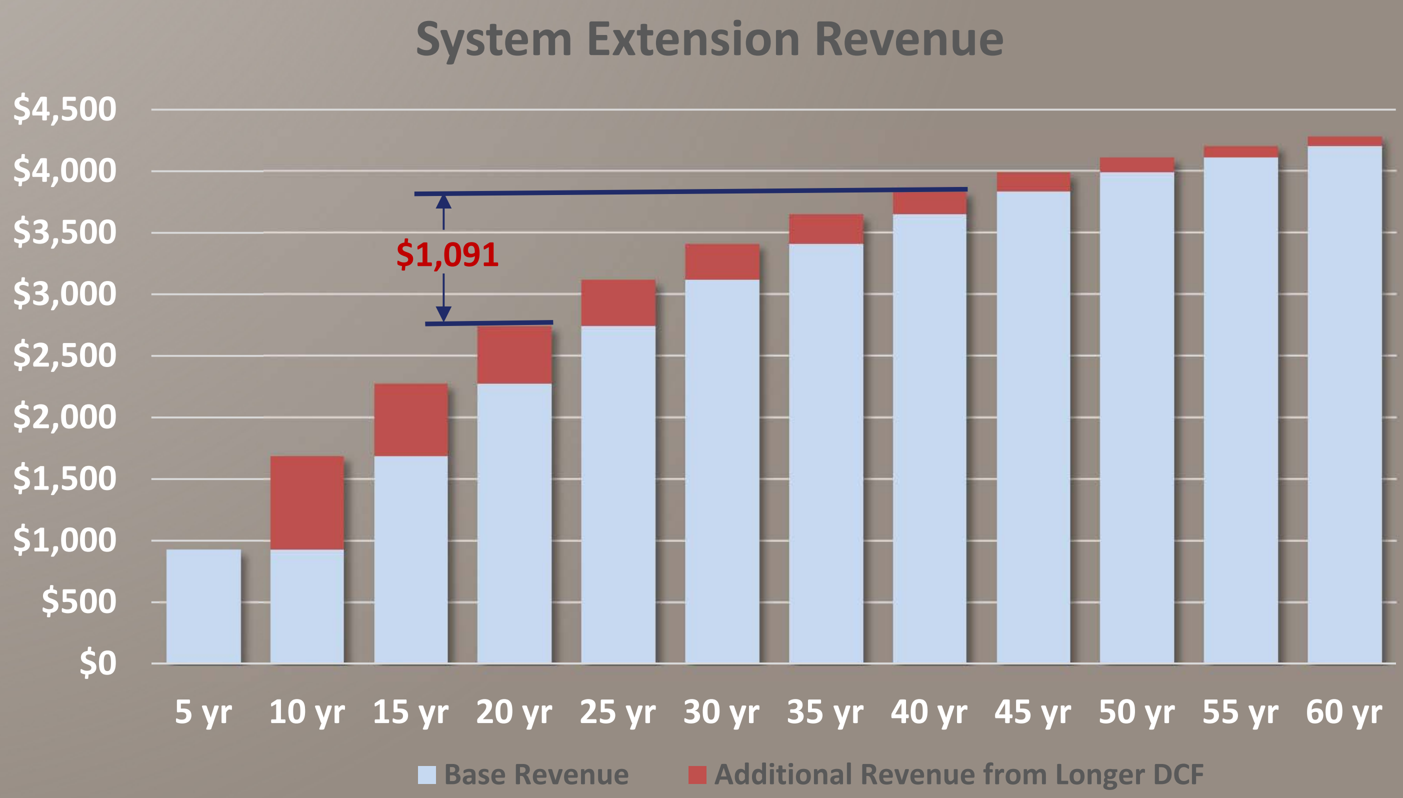
Appliance Consumption

- Current:
  2008 Residential End Use Credit

- **Update:**
  2012 Residential End Use Credit

  - *Consistent with past practices*
  - *FEU average to replace regional values, consistent with amalgamation*

Example System Extension Test



2013 Residential Customer at 67 GJ's per Year

Appliance Consumption – To be Update January 1st , 2015

Current | Updated | $ Impact

Appliance	2011-2014 (GJ/Yr) Lower Mainland	Interior	Vancouver Island	2015 (GJ/Yr) REUS Update FEU	$ Change FEI to FEU
Fireplace	21	20	20	15	($190)
Furnace/Boiler	62	52	43	52	($320)
Hot Water Tank	20	19	19	26	$190
Range/Cooktop	6	5	5	12	$190

- Other appliances but no substantial changes
- Full list is published in 2012 Residential End Use Study

System Extension Policy Change

Attachment Window

- Current:
  5 Year Outlook

- **Update:**

10 Year Outlook

Adjust Refund Window

  - *Provides mechanism to accommodate longer term build-out plans for municipalities and large developers*

Service Line Cost Allowance

SLCA

- Current: $1535
- 19% of customers making a contribution

- **Update: $2,766**
  - *Consistent with 2007 methodology approved by Commission*
  - *23% of customers making a contribution*

Contribution In Aid of Construction (CIAC) Financing

New CIAC Financing Program

CIAC Financing

- Current:
  No program

- **Update:**
  Introduce new CIAC Financing

  - *Consistent with 1996 BCUC Utility System Extension Guidelines*

Fund Objective & Structure

Objective

- Reduce CIAC financial barrier for customers

Structure

- Residential and small commercial customers requesting natural gas service for a residence or place of business
- Any potential in-fill or main extension customer required to pay a contribution in aid of construction (CIAC)
- FortisBC will conduct a credit check
- The debt obligation is linked to the customer (vs. the meter)
- 24 month equal payment with the option to pay off in full at any time

Fund Rate Impact

Historical:

- ***Average $2.4 million/Year in CIAC***
- ***Max. impact assumes 100% opt for financing***

$2.4 million in CIAC Financing	Short Term Debt Rate
Utility Cost of Debt	2.12%
Max. impact per Customer/Year	$.05

Uneconomic Fund

Uneconomic Customers

Uneconomic Fund

- Current:
  No program

- **Update:**
  $1.5 Million Fund for Uneconomic Extensions

  - *Consistent with BC Hydro fund*

Fund Objective & Structure

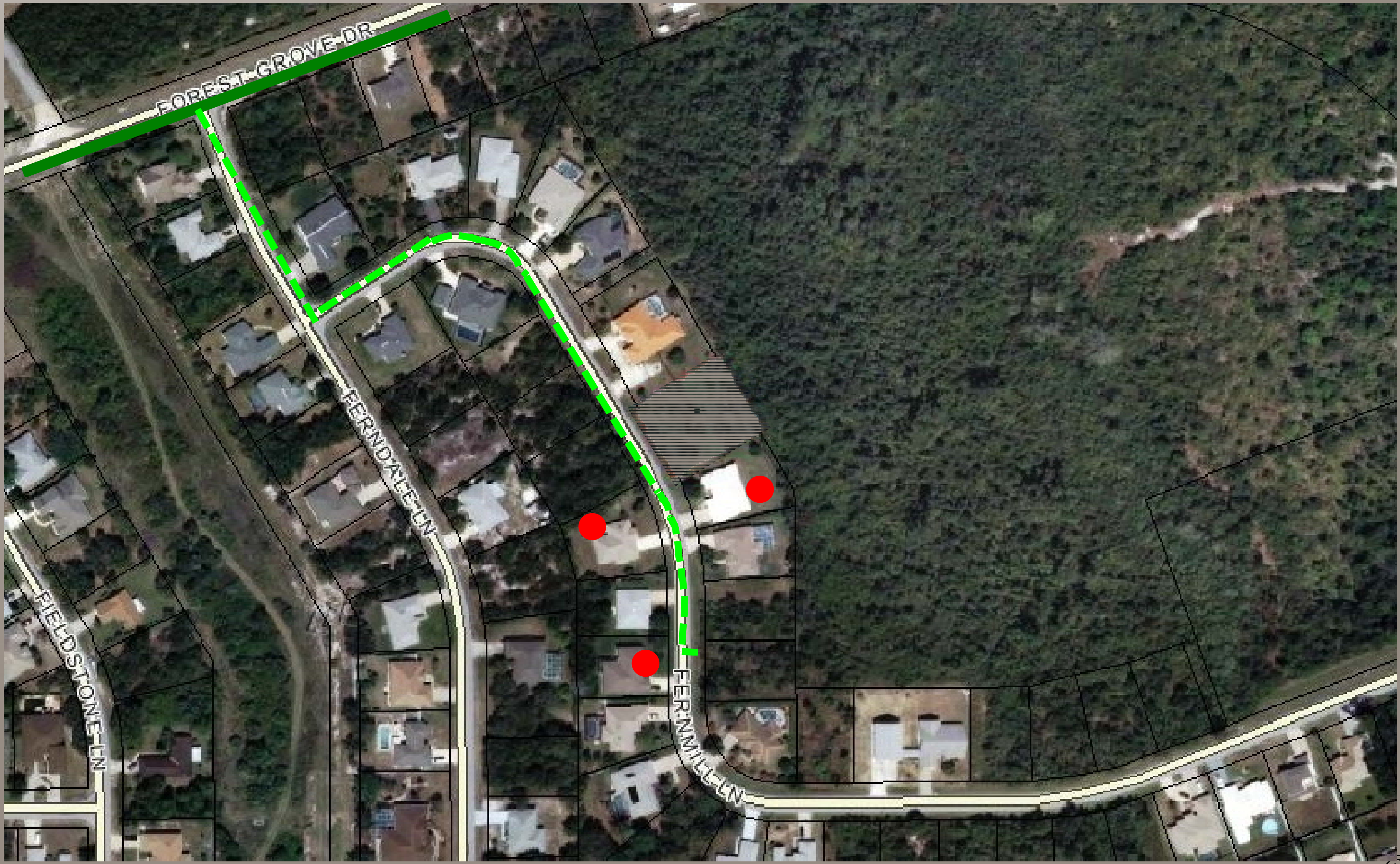
Objective

- Reduce CIAC financial barrier for customers

Structure

- Residential and small commercial customers
- Uneconomic main extensions
- Primary residence or place of business
- Funding weighted towards potential growth in local area
- Customers who opt for assistance from the fund would not be eligible for refunds
- 50% CIAC funding (max.)

Potential Growth Area Example



Comparison

Existing Contributory Main Construct		Access to $1.5 Million Fund	
No Funding Assistance for Customer	Customer must come up with 100% of CIAC	**Funding Assistance for Customer**	Customer CIAC reduced by local growth potential
Full Refund Potential	Customer eligible for full refunds based on additional attachments	**No Refund Potential**	Customer is not eligible for refunds
Lower Growth Potential	Main extension will not proceed without full CIAC paid in advance	**Higher Growth Potential**	Main extension more likely to proceed with reduced CIAC

Policy Changes Summary: Rate Impacts

- Existing customers have saved $12-$18 per year from capital growth (08-13)
- $3 incremental savings per year going forward

Max Rate Impact of Change	
CIAC Financing	$.05
Uneconomic Fund	$.19
	($.24)

$15-23 Million/Year for

Potential Off-System Community Program

Off System Communities Dialogue

Off System Community Program Dialogue

- Seeking support for developing an Off-System Community Program (the Program)
  - Terms of reference & funding

- Preliminary process presented for discussion purposes

Guidelines for Considering Externalities

“The Commission recommends that the Utilities incorporate a reasonable consideration of externalities into their evaluation of system extensions. …extensions where the financial test outcome has been changed from economic to uneconomic or vice versa should be specifically identified.”

-Excerpt from BCUC’s 1996 Utility System Extension Test Guidelines (p.21)

Application:

…”consistent application of social costing principles will take time to develop …further progress on social costing is anticipated by both the Commission and by relevant government ministries.”

Guidelines for Considering Externalities

<u>Externalities:</u>

1. Potential to emerge as unavoidable regulatory costs for the Utilities and their customers

2. Raised on a case by case basis when raised by Intervenors or by explicit government policy expressed in legislation or a special direction

Off System Community Program
Preliminary Terms of Reference

- The purpose of the Program is to facilitate access to natural gas to communities throughout all British Columbia

- The Program will provide access to funding to help overcome the financial barrier of getting natural gas service to off system communities

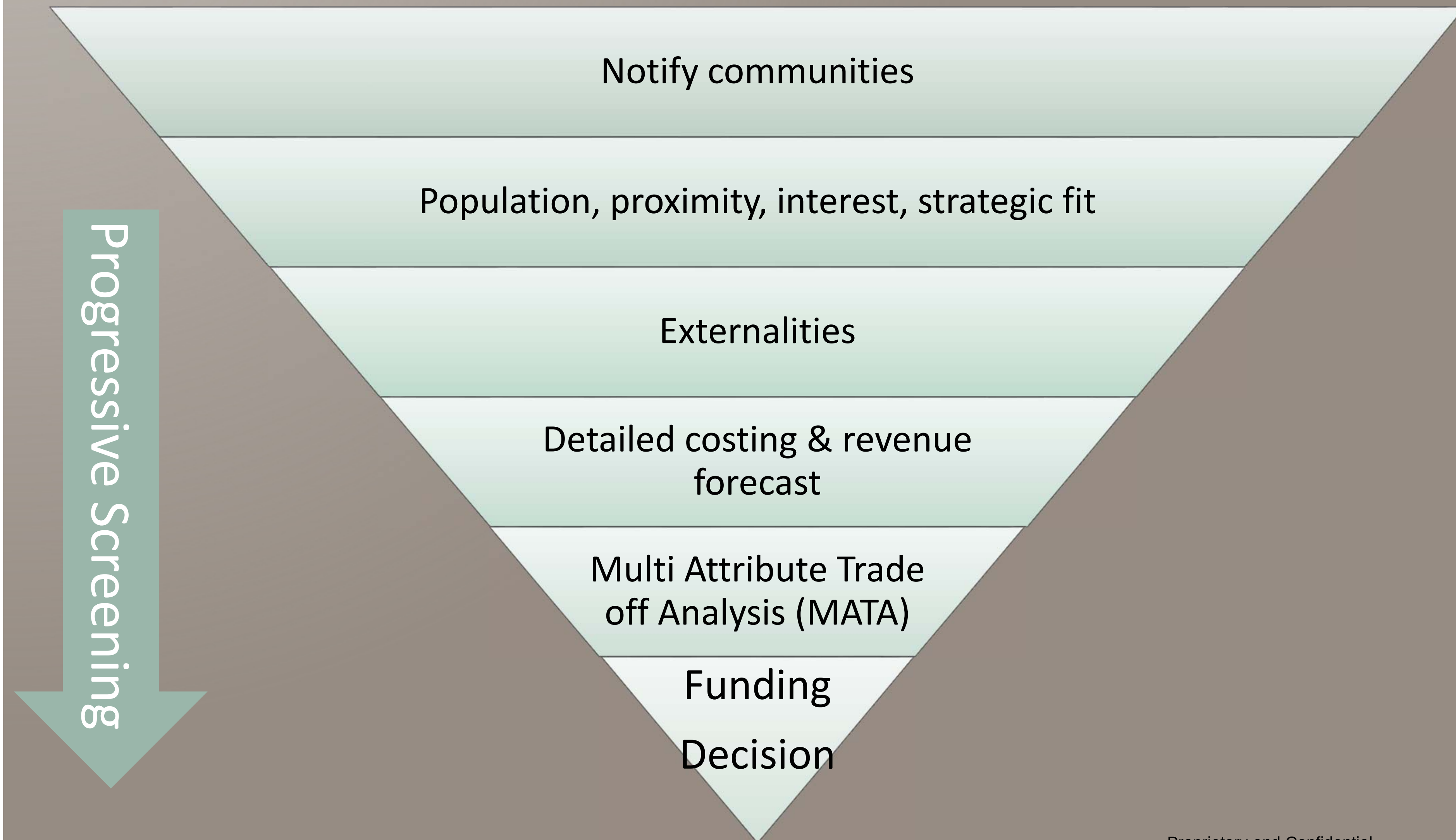
- The Program will allocate funds based on pre-defined process in a fair, equitable and transparent manner

Off System Community Program
Preliminary Funding

- Rate impact analysis indicated $15-$23 M per year could be allocated to the Program

- $15 M could allow for a couple/few communities per year

Off System Community Program
Preliminary Funding Allocation Assessment Model



Step 1 – Initial Screening

- Notify communities of process
- Initial screening = distance from infrastructure, population, interest in gas service
- Strategic fit = gateway community, CNG/LNG transportation corridor

Community Ranking	Measure
High	Closest to infrastructure, largest population, interested in service and good "strategic fit"
Medium	Medium rating
Low	Lowest rating

Step 2 – Externalities Screening

Externalities Consideration	
GHG Reduction - Environmental Impacts	Overall net reduction in GHG's (survey) or other environmental impacts.
First Nations	Presence of First Nations population within a community
Local Economic Growth	Commercial and/or industrial customers that would benefit from natural gas service
Operating Cost Savings	Operating cost savings for those customers who switch energy sources.
Infrastructure savings	Avoided provincial energy infrastructure cost savings
Health Impacts	Potential health impacts of brining natural gas into a community

Step 3-Detailed Costing, Revenue, MATA & Funding Decision

- The top rated communities would progress to Step 3:
  - Detailed costing , revenue forecasts and MATA

- Final funding decision process TBD

Reporting Construct

Reporting Structure

MX Report

- Current: 175+ Tables

- **Update: Rate Impact Report**

Rate Impact Analysis	Main Costs
	Service Costs
	Total Customer Additions by Rate Class
	Consumption of New Customers
	Rate Impacts including Off-System Communities
System Extension Test Update	Potential and completed off-system community connections
	Uneconomic fund activity
Off System Communities & Uneconomic Fund	Parameter Update
	REUS Consumption Update
	Rate Changes

Reporting Timeline

- Discontinue current practice effective immediately
- Revised reporting will be filed with System Extension Policy Application by March 31, 2015
- Further reporting at the time of application to the Commission

Summary & Next Steps

Policy Changes Summary: Stakeholder Feedback

Category	Proposed Changes	Support	Do Not Support	Comments
System Extension Test & SLCA	40 year Test Life			
	Overhead on first $50,000 of Capital Costs			
	Attachment Window of 10 Years			
	Service Line Cost Allowance Updated to $2,766			
CIAC Financing	Equal Payment Plan over 24 Months			
Uneconomic Fund	$1.5 Million Allocated based on Future Potential			
Off System Communities	The purpose of the Program is to facilitate access to natural gas to communities throughout all British Columbia			
	$15 Million in funding to help overcome the financial barrier of getting natural gas service to off system communities			
All	Rate Impact Reporting			

- **Form included in packages**
- **Comments and questions welcome**
- **Response requested by December 15, 2014**

Next Steps

- Stakeholder Feedback by December 15, 2014
- FortisBC Notification to Commission by December 31, 2014
- System Extension Policy Application
- Workshop #5 (Optional) – prescreen application, early March
- Application submission end of Q1 2015
- Off-System Community Program - TBD

System Extension Policy Review Timeline

Date	Event	Topic	Goal	Status
Q4 2013	Individual Stakeholder Consultation	Initial Consultation	Garner Stakeholder support to begin review process.	**Complete**
February 18, 2014	FortisBC System Extension Stakeholder Workshop #1	Policy Issues	Introduction to current issues and agreement to proceed with exploration of policy alternatives.	**Complete**
June 18, 2014	FortisBC System Extension Stakeholder Workshop #2	Term of Reference & Guiding Principles	Stakeholder feedback on principles and objectives which to be used to form the foundation of policy options.	**Complete**
October 8, 2014	FortisBC System Extension Stakeholder Workshop #3	Options Discussion	Review system extension options as developed by Fortis and Stakeholders and opportunity for questions and changes.	**Complete**
December 8, 2014	FortisBC System Extension Stakeholder Workshop #4	Options Discussion	Integrate Stakeholder feedback and confirm proposed changes	**Complete**
December 15, 2014	Stakeholder Feedback		Stakeholder feedback included in application	TBD
Q1 2015	FortisBC System Extension Stakeholder Workshop #5	Prescreen Application	<u>Optional workshop:</u> Review of application	TBD
Q1 2015	Potential Application	Application	Submission of application to Commission	**March 31, 2015**

Mike Metza
Energy Products and Services Manager, FortisBC
16705 Fraser Highway
Surrey BC, V4N 0E8
604-592-7852
mike.metza@fortisbc.com

To: System Extension Policy Workshop Stakeholders **Date : December 8, 2014**

Re: Feedback On System Extension Policy Proposals

In late 2013 FortisBC began a consultation process with stakeholders to review its current system extension policies. As a part of this process, we are asking you to please fill in the table below and submit it to FortisBC no later than December 15, 2014.

The overall objective of the system extension review stakeholder workshop process has been to review system extension constructs in order to identify changes that could make it easier for various customer types to access natural gas service. The guiding principles developed with stakeholders are as follows:

- Protect existing ratepayers
- Represent First Nations and off-system community interests
- Maintain consistency with government objectives
- Provide an energy choice
- Ensure policies are easy to understand

After individual meetings with stakeholders and four workshops which took place throughout 2014, the Company is requesting that stakeholders indicate their support and provide comments on the proposals developed during the workshop process by December 15, 2014. The Company will be using this feedback to determine its next steps in considering a potential application to the Commission. By December 31, 2014, the Company must indicate to the Commission whether or not it will be submitting a system extension application.

If you have any questions or wish to discuss any of the items included in the table below, please contact Mike Metza at 604-592-7852, or mike.metza@fortisbc.com.

Thank you

FortisBC System Extension Stakeholder Feedback Form

Name:

Organization:

Date:

Signature:

Category	Proposed Changes	Support	Do Not Support	Comments
System Extension Test & SLCA	40 year Test Life	○	○	
	Overhead on first $50,000 of Capital Costs	○	○	
	Attachment Window of 10 Years	○	○	
	Service Line Cost Allowance Updated to $2,766	○	○	
CIAC Financing	Equal Payment Plan over 24 Months	○	○	
Uneconomic Fund	$1.5 Million Allocated based on Future Potential	○	○	
Off System Communities	The purpose of the Program is to facilitate access to natural gas to communities throughout all British Columbia	○	○	
	$15 Million in funding to help overcome the financial barrier of getting natural gas service to off system communities	○	○	
All	Rate Impact Reporting	○	○	

Appendix C

COMMISSION LETTERS AND RESPONSES

ERICA HAMILTON
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

LETTER L-34-14

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TELEPHONE: (604) 660-4700
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VIA EMAIL
gas.regulatory.affairs@fortisbc.com

June 19, 2014

Ms. Diane Roy
Director, Regulatory Affairs - Gas
FortisBC Energy Inc.
Surrey, BC V4N 0E8

Dear Ms. Roy:

Re: FortisBC Energy Inc. and FortisBC Energy Vancouver Island Inc.
2013 Main Extension (MX) and Vertical Sub-division Reports

The British Columbia Utilities Commission (Commission) acknowledges receipt of the 2013 Main Extension (MX) and Vertical Sub-division Reports (Report) submitted by FortisBC Energy Inc. (FEI) and FortisBC Energy Vancouver Island Inc. (FEVI) (collectively, the Companies). Considering the 2013 MX Report results, including the five year results for the 2008 mains extension year, which appear to show a significant under-recovery of those mains extension costs, and the Commission's observations on the Companies' forecasting methods and security and ratepayer protection policies, the Commission seeks comment on the Companies' main extension performance and policies before deciding how to proceed.

Specifically, the Commission requests the Companies and interested parties to provide comments to the Commission, on or before July 15, 2014, on the items outlined on page 5 of this Letter.

Background

On July 31, 2007, pursuant to the *Utilities Commission Act*, Terasen Gas Inc. (TGI) and Terasen Gas (Vancouver Island) Inc. (TGVI), predecessors to FEI and FEVI, jointly filed an application to amend the Terms and Conditions of each utility's Tariff with respect to charges for system extensions and customer attachment and connections (Application).

On December 6, 2007, by Order G-152-07, the Commission issued its Decision on the Application. In its Decision, the Commission Panel directed TGI and TGVI to file with the Commission on an annual basis, within 90 days of calendar year end, a main extension report containing certain information.

On March 27, 2014, FEI and FEVI jointly submitted to the Commission their 2013 MX Report, which includes results based on 5 years of data for 2008 main extensions.

The Commission acknowledges that the Companies are currently engaged in a stakeholder review of their main extension policies. However, it appears that the Companies' process includes neither a review of the Companies' performance, nor a review of the specific concerns that the Commission notes below. The Commission also believes a more timely review process is appropriate.

Overview of Issues

On August 18, 2010, TGI and TGVI filed a revised 2009 MX Report in which they affirmed "...the results of the main extensions at the end of the five-year time period is the appropriate time to determine the appropriateness of the forecasts developed at the time of the main installation request..." (Revised TGI and TGVI 2009 MX Report, p. 15). As the 2013 MX Report includes results for 2008 main extensions at the end of the five-year time period, the Commission considers it time to determine the appropriateness of the Companies' main extension forecasts.

> "The Profitability Index [PI] 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. While there are many components factored into the calculation of this ratio, the following formula provides a summary of the major components:

$$\text{P.I.} = \frac{\underset{\text{(Delivery Margin + Connection Fees – O\&M - System Improvement Charge – Property Tax – Income Tax)}}{\textbf{Net Present Value of Net Cash Inflows}}}{\overset{\text{(Mains, Services, Meter Costs)}}{\textbf{Net Present Value of Capital Costs}}}$$

> Accompanying the MX Test formula are the following FEI and FEVI MX Test threshold criteria that have been approved by the Commission under Order No. G-152-07:
>
> - 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 is required to bring the PI up to the 0.8 threshold, before the system extension can be built.
> - An aggregate threshold PI of 1.1 is to be used for the portfolio of main extensions completed on an annual basis." (2012 MX Report, p. 10)

A PI of less than 1.0 indicates that the net present value of the net cash inflows (actual net cash inflows in the reporting period plus the forecast net cash inflows) over twenty years is less than the discounted present value of the actual capital costs of attaching customers in the first five years.

For the 2008 main extension year, the Companies report actual individual PIs and actual aggregate PIs below the minimum required thresholds of 0.8 and 1.1, respectively.

The Commission is concerned that the 2008 aggregate PI results over the five year period were below 1.0, indicating that existing ratepayers might be exposed to an undue cost burden as a result of the expansion of the distribution system to attach these new customers.

For ease of reference, the five year results for the 2008 main extension year provided in the Report are repeated below:

2008 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.60	0.54	-66%
Years 1-5 Total	1.60	0.54	-66%

(2013 MX Report, p. 113)

2008 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Trans-Canada Hwy	1.00	0.07	-93%
Juniper Road	1.70	0.00	-100%
Crystal Creek Drive	1.00	0.08	-92%
61A Avenue	1.38	0.59	-57%
Rio Drive	1.00	0.09	-91%
Years 1-5 Average	1.22	0.17	-86%

(2013 MX Report, p. 121)

2008 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.30	0.61	-53%
Years 1-5 Total	1.30	0.61	-53%

(2013 MX Report, p. 115)

2008 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Players Drive	1.55	0.24	-84%
French Road	1.22	0.16	-87%
Hutchinson Road	1.40	0.46	-67%
Sewell Road	1.03	0.48	-54%
Phillips Road	0.88	0.00	-100%
Years 1-5 Average	**1.22**	**0.27**	**-78%**

(2013 MX Report, p. 126)

The Commission has identified two areas of concern it believes are contributing to the gap between forecast PIs and actual PIs over this period. These are:

1) forecasting accuracy, and
2) security and existing ratepayer protection in the event that costs, attachments and/or consumption do not materialize according to forecast estimates.

1. Forecasting Accuracy

Forecasting accuracy refers to the accuracy of the inputs used in the forecast PI calculations. Inputs include, but are not limited to, main extension costs, number of attachments, timing of attachments, use per customer, and application of efficiency credits. Forecasting lower costs, a greater number of attachments, earlier attachments, and/or a higher use per customer than actual may result in a main extension meeting the main extension test with less (or no) contribution from the customer(s) than what the customer(s) should have contributed.

There have been main extensions where actual costs have been higher than the Companies' forecasts and this has contributed to actual individual PIs being lower than the required minimum threshold of 0.8, for example, Shawinigan Lake (2013 MX Report, Table 137, p. 105 and Table 147, line 1, p. 111) and Crystal Creek (2013 MX Report, Table 158, p. 118, Table 164, line 3).

There have also been main extensions where actual attachments have been fewer and later than the Companies' forecasts and this too has contributed to actual individual PIs being lower than the required minimum threshold of 0.8, for example, Juniper Road (2013 MX Report, Table 157, p. 117) and Rio Drive (2013 MX Report, Table 163, p. 120). The Companies have stated that the 2008 main extension year was impacted by the economic downturn and is why attachments did not materialize as forecasted (Revised TGI and TGVI 2009 MX Report, p. 1).

For almost every main extension, actual consumption (use) per customer has been significantly less than forecast (2013 MX Report, pp. 41-126). In the Executive Summary of the Report, the Companies state that actual consumption levels are consistent with new customers (2013 MX Report, pp. 1-2).

The Companies explain:

> "Consumption is calculated by determining the annual usage estimates by appliance type derived from operational experience and the Companies' own Residential End Use Study ("REUS") for **existing** customers." (Emphasis added) (2013 MX Report, p. 11)
>
> "However, it is important to note that new customers' (**actual**) consumption patterns **differ from existing customers** due the adoption of current efficiency technology in housing and that the forecast levels used in MX Test represent the consumption levels of all existing customers on the Companies' distribution system who connected to the system..." (Emphasis added) (2013 MX Report, p. 1)

From the data provided in previous reports, the primary difference between new customers and existing customers is that new customers' consumption is less than existing customers' consumption (2011 MX Report, pp. 21-22). Forecasting new customer consumption based on existing customer usage estimates will result in inaccurate PI forecasts because new customers are expected to use less gas than existing customers.

It also appears that when the Companies forecast individual PIs, they are applying 10 percent and 15 percent efficiency credits to existing customer consumption levels (2013 MX Report, p. 12). If this is correct, it would act to further inflate consumption forecasts for new customers.

> "Customers who install both high efficiency gas fired space and water heating receive a credit of 10 percent of the volume otherwise used for both appliances." (2013 MX Report, p. 12)
>
> "Customers who install both high efficiency gas fired space and water heating appliances and attain a minimum of LEED^{TM} (Leadership in Energy and Environmental Design) General Certification receive a credit of 15 percent of the volume otherwise used for both." (2013 MX Report, p. 12)

Using existing customers' consumption estimates would tend to cause forecasts for new customers' net revenue and therefore forecasts for new customers' individual PIs to be overstated. Similarly, adding efficiency credits to existing customers' consumption estimates would tend to cause forecasts for new customers' net revenue and therefore forecasts for new customers' individual PIs to be further overstated. Overstating forecasts for new customers' individual PIs would tend to lead to overstating forecasts for new customers' aggregate PIs.

Therefore, to achieve actual individual PIs of at least 0.8 and actual aggregate PIs of at least 1.1, the forecast individual target PIs must be higher than 0.8 and the forecast target aggregate PIs must be higher than 1.1.

2. Security and Existing Ratepayer Protection

Section 12.6 of the Companies' General Terms and Conditions reads:

> "Contributions in Aid of Construction - If the economic test results indicate a Profitability Index of less than 0.8, the Main Extension may proceed provided that the shortfall in revenue is eliminated by contributions in aid of construction..." (2013 MX Report, Appendix B, Section 12.6, p. 12-2).

Section 12.10 of the Companies' General Terms and Conditions reads:

> "Security - In those situations where the financial viability of a Main Extension is uncertain, FortisBC Energy may require a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy." (2013 MX Report, Appendix B, Section 12.10, p. 12-3)

It is possible, had the Companies obtained sufficient contributions in aid of construction or other securities for main extensions where the actual costs were higher, attachments were fewer or later, and/or customer consumption was lower than forecasted, the potential exposure to existing ratepayers of an undue cost burden as a result of the expansion of the distribution system to attach new customers would have been mitigated.

Submissions Sought

Considering the 2013 MX Report results, including the five year results for the 2008 mains extension year, which appear to show a significant under-recovery of those mains extension costs, and the Commission's observations on the Companies' forecasting methods and security and ratepayer protection policies, the Commission seeks comment on the Companies' main extension performance and policies before deciding how to proceed. Specifically, the Commission requests the Companies and interested parties to provide comments to the Commission, on or before July 15, 2014, on the following:

1. What should be the scope and process for a more detailed review of the Companies' main extension performance and policies?
2. Comment on the Companies' security and ratepayer protection policies. What changes to these policies should be made, if any?
3. Comment on the Companies' forecasting performance. What changes to the Companies' forecasting methods should be made, if any?
4. Comment on the urgency of a review and what should the Companies and the Commission should do in the interim?

Yours truly,

Erica Hamilton

CG/cms

cc: Registered Interveners
FBC-PBR-2014-18-RI; FEI-PBR-2014-18-RI; TGVI-TGI-SyX&CPR-RI

Dennis Swanson
Director, Regulatory Affairs

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Email: electricity.regulatory.affairs@fortisbc.com

July 9, 2014

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI) and FortisBC Energy (Vancouver Island) Inc. (FEVI) (collectively the FEU or the Companies) 2013 Year End Report for:

- **FEI-FEVI Main Extension (MX) Report – British Columbia Utilities Commission (the Commission) Order G-152-07 Compliance Filing; and**
- **FEI Vertical Subdivision Report – Commission Order No. G-6-08 Compliance Filing**

The Companies' Response to Commission Letter L-34-14

The Companies have reviewed the Commission's Letter L-34-14 and provide the following response.

While the Companies do not agree with the observations of the Commission with respect to forecast accuracy and the Companies' security and ratepayer protection policies, the Companies recognize that there are concerns with the system extension and customer connection policies (the Policies) in place and that they need to be reviewed and alternatives considered. To address these concerns, the Companies have begun a consultative process by engaging with a wider group of stakeholders, including Commission staff, who are interested in the Policies. Following this stakeholder engagement and consultative process on the Policies (the Consultation Process), the Companies intend to file with the Commission the results of the Consultation Process and a proposal for changes to the Policies intended to resolve the concerns. The Consultation Process will allow the FEU to bring forward a proposal that is informed by a broad array of stakeholders and considers issues raised that are more broadly impacted by the Policies, both directly and indirectly. Continuation of the Consultation Process will allow the FEU to put forward a proposal with the necessary evidence to enable the Commission to assess the proposal for changes to the Policies and potential alternatives. In the FEU's submission, any alternative or additional process introduced at this time by the Commission would not be practical because it would be duplicative, would result in additional time and costs for participants, and would likely cause confusion with the existing Consultation Process that is already underway. Further, the FEU believe that given the regulatory calendar of proceedings currently before the Commission, continuing with the Consultation Process already underway presents the most efficient, effective, timely, thorough, and informed review of the Policies.

In this letter, the FEU provide the Commission with some details on the FEU's Consultation Process that is underway and then respond to the Commission's four questions as set out in Letter L-34-14.

Background on Existing Stakeholder System Extension Review Process

After the submission of the 2011 Main Extension Report, the Companies engaged EES Consulting, Inc. (EES Consulting) to examine the system extension and customer connection policies, tests and practices in other jurisdictions. The purpose was to determine if the current FEU Policies should be reviewed more substantially. Upon receipt of the report from EES Consulting (the EES Report) the FEU determined that a review of the Policies was required. The Companies submitted the EES Report as part of the 2012 Main Extension Report[1]. Following submission of the 2012 Main Extension Report, the Companies began meeting with various individual stakeholders to seek their input on proceeding with a review of the Policies to address gaps and concerns in the current Policies as they relate to the different types of system extension customers. On February 18, 2014, the Companies held the first stakeholder workshop on the Policies, which was attended by Commission Staff. The workshop was designed to educate and inform stakeholders on the specific issues arising from the Polices, such as:

- the inability of the system extension test to recognize the full benefits associated with connecting a new customer;
- the inadequacy of the current Policies to enable off system communities to access natural gas in a reasonable and cost effective manner; and
- the overall difficulty all customers face in interpreting and understanding the costs associated with a natural gas connection as a consequence of the current Policies.

As a result of the workshop, participants agreed to proceed further with the review of the Policies. A subsequent workshop was then held on June 18, 2014, where stakeholders, including Commission Staff, provided input on a Terms of Reference (the Stakeholder Terms of Reference) for the development of new Policies. The Stakeholder Terms of Reference are attached as Appendix B.

The Companies are currently using the Stakeholder Terms of Reference as a framework for the development of several options related to the Policies which will be reviewed in detail at a third workshop scheduled for October 8, 2014. A fourth and final workshop will be held during the fourth quarter of 2014. The schedule of the Consultation Process is proceeding as quickly as reasonably possible given the availability of the participants.

The goal of the workshops and the Consultation Process is to arrive at a new set of Policies and a system extension test designed to address the concerns of all stakeholders related to

[1] FEI-FEVI Main Extension Report for 2012 Year End – submitted March 28, 2013.

the current Policies. The planned outcome of the Consultation Process is the filing of an application with the Commission in the first quarter of 2015, for approval of new Policies which have the support of stakeholders.

The Companies note that Letter L-34-14 was provided only to Registered Interveners involved in past Commission proceedings and that the distribution list did not include some of the stakeholders participating in the Consultation Process already underway. As these stakeholders have already invested their time, resources and attention to the current Consultation Process for review of the Policies, the FEU have forwarded a copy of Letter L-34-14 and this response by the FEU to the list of stakeholders involved in the Consultation Process, which is provided in Appendix A.

The FEU believe that the Consultation Process already underway with stakeholders to review the Policies should proceed as planned, which will allow the FEU to engage and work with a broad range of stakeholders collaboratively, and then bring forward a proposal to the Commission for changes to the existing Policies, including the system extension test and reporting requirements. As such, the FEU's general response to the Letter L-34-14 is that no additional or further process is needed at this time, but rather the FEU should continue with the Consultation Process that is already underway.

Response to Commission Questions

The FEU have provided responses to the particular questions posed by the Commission below. For reference, the four questions posed by the Commission in L-34-14 are as follows:

1. *What should be the scope and process for a more detailed review of the Companies' main extension performance and policies?*
2. *Comment on the Companies security and ratepayer protection policies. What changes should be made if any?*
3. *Comment on the Companies' forecasting performance. What changes to the Companies' forecasting methods should be made, if any?*
4. *Comment on the urgency of a review and what should the Companies and Commission do in the interim?*

The FEU provide their responses below.

1. What should be the scope and process for a more detailed review of the Companies' main extension performance and policies?

The FEU believe the appropriate scope and process for a review is already set out in the Stakeholder Terms of Reference included as Appendix B. The Stakeholder Terms of Reference reflects the recommended scope and process agreed to by stakeholders involved in the FEU's Consultation Process on the Policies, and includes the issues raised by Commission Staff on reporting and performance.

Stakeholders have indicated that the purpose of the Consultation Process should be to examine broad policy issues and the impacts on various customer types. During the workshop, Commission Staff have raised the issue of the differences between the system extension test and the subsequent system extension reporting. The Companies' intention, as stated during the workshop, is that once stakeholders arrived at a supported set of Policies, the appropriate level of reporting and associated methodologies should be examined at that time. As seen in the Stakeholder Terms of Reference in Appendix B, performance and reporting are included as a part of the scope of the Consultation Process.

Given the interest of many stakeholders in the Policies, the FEU believe that the Consultation Process that the FEU have commenced is an appropriate process to undertake, prior to any Commission review of the Policies. The FEU's Consultation Process will lead to an Application by the FEU that will have the benefit of stakeholder consultation and will facilitate a complete review by the Commission.

2. Comment on the Companies security and ratepayer protection policies. What changes should be made if any?

The FEU have consistently followed the parameters established by the Commission for the system extension test, Contributions In Aid of Construction (CIACs) and security. However, the existing system extension reporting provides misleading results that should not be used to determine the required degree of rate payer protection. In addition, the protection of existing ratepayers must be balanced with the requirements to serve new customers and the expectations of new customers that they will not be unduly burdened when connecting to the system.

Based on the quote below, it appears that the Commission has determined that ratepayer protection policies need to be assessed based on the results of the system extension report, a specific selection of which was included in Letter L-34-14. Letter L-34-14 states:

> *"It is possible, had the Companies obtained sufficient contributions in aid of construction or other securities for main extensions where the actual costs were higher, attachments were fewer or later, and/or customer consumption was lower than forecasted, the potential exposure to existing ratepayers of an undue cost burden as a result of the expansion of the distribution system to attach new customers would have been mitigated."*[2]

The Companies respectfully disagree with the suggestion that there is "…potential exposure to existing ratepayers of an undue cost burden…" The system extension report results should not be used to determine whether ratepayers are exposed to an undue cost burden. The system extension test cannot measure the final economic impact of a system extension on ratepayers and, as discussed in response to question Number 3 below, the current associated system extension reporting construct is flawed in that it is simply a re-forecast of the original forecast test. Instead, any decision to change the current Policies should be based on the outcome of the Consultation Process that is currently underway and the FEU's subsequent application to the Commission.

The Companies believe that before the levels of ratepayer protection can be examined, a more representative measure of the financial impacts of a system extension on ratepayers must be devised through the Consultation Process. Furthermore, rate payer protection policies should then be defined within the context of a new set of Policies generally. General

[2] L-34-14, page 5.

ratepayer protection policies will be defined and examined in conjunction with the system extension test options that will be discussed in the third workshop (see Appendix B for detail).

For clarity, further explanation is provided of ratepayer protection policies, the system extension test, CIACs and security:

i. Rate Payer Protection Policies & the System Extension Test:

The current system extension test can be classified as a "ratepayer protection policy" in that the customer must pass the test before being connected to the system. When a customer calls to connect, the Companies use information known at the time and apply that information to the system extension test as approved by the Commission. This ultimately determines if the customer must contribute to the cost of the extension. In the event of a required contribution, the customer must provide a CIAC in order to proceed with their connection (CIACs are discussed below). The current system extension test creates a layer of protection for existing ratepayers by providing a forecast figure that is intended to generally reflect the costs and benefits of connecting a new customer during the first five years of the extension. The test adds a layer of rate payer protection and helps the Companies assess whether a customer should pay a portion of the connection cost based on a set of conservative assumptions. A table describing the inputs and assumptions used in the system extension test and approved by the Commission can be found in Appendix C.

ii. CIAC (Contribution In Aid of Construction):

A CIAC occurs when the system extension test determines that a customer must pay a portion of the cost to reduce the amount of capital the Companies put into an extension and is based upon the rules in the Tariff. A CIAC may also be refunded in whole or in part as additional customers attach to the system.

The Companies must run the approved system extension test in the same manner for all customers based on input parameters such as the total cost, number of attachments and types of appliances that are forecast to occur during the first five years of the system extension. The approved system extension test input parameters and methodologies follow the BCUC Utility System Extension Test Guidelines[3] and are most recently approved by Commission Order G-152-07.

iii. Security:

The FEU believe the security provisions within the Tariff, and implemented by the Companies, are appropriate and that to strengthen these mechanisms at this time would punish and impose costs on developers further restricting the ability to add customers.

The Companies have the option to request security if they are uncertain of a customer's commitment to install the specific appliances, in the time frame expected, used in the forecast test. Security can provide a further level of ratepayer protection in the event a builder or developer did not deliver on their commitments. The Companies have the ability under Section 12.10 of the General Terms and Conditions of the FEI and FEVI

[3] BCUC Utility System Extension Test Guidelines, issued September 5, 1996.

tariffs to ask for security. However, it should be noted that security is seen by some developers and customers as a punitive measure. Developers do have control over what appliances are in the house/unit but do not control the end use customer's usage or the exact time frame that the customer connects to the gas system.

As can be seen from the above, the Companies security and ratepayer protection policies are inherently connected to the system extension test which itself is a ratepayer protection policy. As such, changes, if any, to these Policies should be made with the benefit of input from the Consultation Process currently underway and the resulting application that the FEU will file with the Commission.

3. Comment on the Companies' forecasting performance. What changes to the Companies' forecasting methods should be made, if any?

The FEU believe that the forecasting performance is appropriate, follows approved mechanisms, and that no immediate change is required. However there are inherent flaws in the way in which performance is measured in the current system extension test annual reporting requirements. Making changes to one aspect of the test without consideration of the entire test could lead to unintended consequences and issues of intergenerational inequity. The FEU therefore believe that any changes to the Companies' forecasting methods should be made with the benefit of and informed by the Consultation Process underway and the resulting application to be made to the Commission by the FEU.

The current system extension test, as approved by the Commission, uses a variety of agreed upon forecasted inputs to serve as a proxy for the expected actual economic performance of a system extension over a certain period of time. (Further details on the test inputs, their assumptions, and their impact on the system extension results are discussed in Appendix C). The system extension test is meant as a mechanism to try to ensure that existing rate payers are not unduly harmed by the addition of new customers and that the barrier to attach for new customers is not too high. The test is a forecast only and therefore does not truly depict the actual economic impact on the system over the life of the asset. As noted above and further reviewed below, the annual reporting mechanism uses different inputs than the original forecast to create a "re-forecast" and therefore cannot, in its current format, be used for reliable comparison. Actual performance of a main can only be determined at the end of the useful life of the asset.

The Companies believe that both the existing system extension test and reporting underestimate the benefit and overestimate the cost impact of Main Extensions on the FEU's existing customers. With respect to the Companies' forecasting performance, there are three issues that need to be taken into consideration:

(1) customer attachments have not always aligned with forecasts;

(2) the current average use per appliance has been lower than the historic use; and

(3) there are attachments that occur beyond the first five years which are not taken into account nor examined through the current system extension test reporting.

Note that these are all aspects of the system extension test that will be reviewed in the Consultation Process currently underway.

A more detailed discussion of the specific aspects of forecasting performance reflected in the annual reports to the Commission is provided below.

i. Actualized Use per Customer

The Companies' consumption forecasts used in the system extension test are based on the best available information and data at the time of formulation. The current methods draw forecasts directly from the actual consumption of all existing customers and are separated based on geographic region and appliance type. At the time of forecast, the expected annual consumption values derived by the Companies is accurate in that they are reflective of the existing customer base.

When the Companies apply the system extension test for a new customer they use the average consumption by appliance type based on the average of all existing customers based on the results of the Residential End Use Study (REUS) as approved by BCUC Order G-152-07. The average consumption provides a proxy for the revenue portion of the system extension test which directly impacts the test result and ultimately how much a customer will have to pay to connect to the system.

A new customer, however, may consume less gas than the existing average because new customers generally connect with highly energy efficient appliances and buildings (as opposed to existing customers who may have a mix of new efficient appliances and buildings as well as inefficient housing and appliance stock). Furthermore, whether new or existing, the Companies cannot control how much gas a particular customer will use in each appliance. A customer may have a furnace installed but could use the appliance differently depending upon personal habits.

The FEU met with Commission staff and agreed to use actual consumption when re-calculating and re-forecasting the test for reporting purposes. Given that this consumption value is different than what the Commission approved for the original test, the re-forecast test result will typically be lower than the original test result. This does not necessarily indicate a fault in the system extension test or other aspects of the Policies but rather indicates a potential misalignment with the system extension test and the system extension reporting, which is one of the reasons why the system extension test and any reporting that may be required are being re-examined through the ongoing Consultation Process.

While Letter L-34-14 indicates that forecasting consumption may be a negative issue, the Companies believe that a lower consumption value for new customers is a positive outcome as it is indicative of and reflects the success of recent energy efficiency initiatives promoted by the provincial government and the Companies through its Energy Efficiency and Conservation programs. As indicated in Appendix B, stakeholders have indicated that promoting energy efficiency is a key priority for the system extension review.

It is also important to note that the test does not consider customers who connect to the system beyond the first five years and, therefore, no consideration is given to the additional benefits these further customer connections and their resulting gas consumption have to the system and to all FEU customers.

ii. Number of Attachments

Customer attachments to the Companies' distribution system and the BC housing market are closely related and both are highly cyclical in nature. In general, the Companies work closely with a wide range of potential customers from homeowners to large developers to develop good-faith estimates of the appliances and expected time of attachments on new system extension projects. However, similar to other utilities such as water and electricity, the Companies' forecasts are affected by economic conditions and a multitude of other variables which can result in a variance between forecast and actual attachments. In most cases, unrealized attachments are simply delayed, and when considered beyond their respective forecast year, the majority of forecasted attachments will materialize.

The current reporting uses a methodology of re-forecasting attachments that presents the worst case scenario for attachments. As a result, the forecasting performance of attachments is not reflective of actual performance over the life of the assets.

In particular, based on the current reporting the Companies are required to ignore all future potential on a system extension. For example if a builder of a subdivision expects to have 10 homes completed by the end of the first year, and was only able to complete 5 then the re-forecasted attachments assume that only 5 homes will ever attach to the system. This significantly understates the system extension test results thereby providing re-forecasted results that cannot be compared with the original forecast and are not representative of the actual performance of the extension over its useful life. In reality, the missing 5 attachments in the example will likely appear in the future, as will additional, un-forecasted attachments.

As demonstrated, the FEU believe that the forecasting performance is appropriate, follows approved mechanisms, and that no immediate change is required. The FEU therefore believe that any changes to the Companies' forecasting methods should be made with the benefit of, and informed by, the Consultation Process underway and the resulting application to be made to the Commission by the FEU. This has been captured in the Stakeholder Terms of Reference as indicated in Appendix B.

4. Comment on the urgency of a review and what should the Companies and Commission do in the interim?

The Companies believe that a review of the Policies is warranted as evidenced by the process it has already begun with stakeholders, and that the Policies should remain unchanged in the interim. The urgency of the review is driven in part by those customers and communities who do not already have access to natural gas but want the option to use natural gas in their homes and businesses.

The Consultation Process currently underway is intended to define a new set of Policies that will address the needs of the different types of customers and stakeholders, including the concerns noted by the Commission.

The Companies submit that the current Policies should remain unchanged until the completion of the Consultation Process, the subsequent filing of an application by the FEU, and final disposition of the FEU's application by the Commission. Any short-term changes put in place, either interim or permanent, would be a reactionary measure which could have unintended and unforeseen consequences, would result in confusion, and could potentially cause an undue burden on both new and existing customers.

Conclusion

The FEU believe that initiating an additional process at this time would confuse the existing Consultation Process already underway and would be inconsistent with what has been agreed upon by stakeholders involved in the current Consultation Process. For the reasons discussed above:

1. The existing Consultation Process should continue.
2. The current rate payer protection policies are appropriate and are best left in place until such time as the Consultation Process has been completed, and changes, if any, can be presented with the benefit of evidence and input from the Consultation Process.
3. The Companies forecasting performance is reasonable at this time and meets Commission's direction. However, as part of the existing Consultation Process, forecasting matters will be reviewed and addressed as may be required.
4. To the extent that there is any urgent need to review the Policies, the existing Consultation Process should continue as it is the most efficient, effective and timely process in which to address all issues.

Yours very truly,

FORTISBC ENERGY INC.
FORTISBC ENERGY (VANCOUVER ISLAND) INC.

Original signed:

Dennis Swanson

Attachments

cc (email only): Stakeholders participating in the Consultation Process
Registered Parties to the:

- FEI 2014-2018 PBR Proceeding
- FBC 2014-2018 PBR Proceeding
- FEU 2007 System Extension Proceeding

Appendix A

ADDITIONAL LETTER RECIPIENTS

Stakeholder	Attendee	Title
BC Chamber of Commerce	**Susan Payne**	Executive Director, Ucluelet Chamber of Commerce
Commercial Energy Consumers Association of British Columbia	**David Craig**	Executive Director
Chawathil First Nation	**Norman Florence**	Council Member
EES Consulting	**Gail Tabone**	Senior Consultant, EES Consulting
Fraser Valley Regional District	**Lloyd Foreman**	Director, Electoral Area A
Fraser Valley Regional District	**Dennis Adamson**	Director, Electoral Area B
MJT - Ministry of Jobs, Tourism and Skills Training	**Robert Wood**	Acting Director, Major Investments Office
MLA Boundary - Similkameen	**Colleen Misner**	Constituency Assistant to Linda Larson, MLA
Okanagan - Similkameen Regional District	**George Bush**	Board Member
PNG – Pacific Northern Gas	**Janet Kennedy**	Vice President, Regulatory Affairs and Gas Supply
PNG – Pacific Northern Gas	**Peter Schriber**	Manager, Financial Planning & Business Development
PRRD - Peace River Regional District	**Karen Goodings**	Board Director
Seabird Island Band	**Brian Titus**	Consultant
Seabird Island Band	**Chief Clem Seymour**	Chief
Yale First Nation	**Steven Patterson**	Natural Resource Manager
First Nations Energy and Mining Council	**Katie Terhune**	Consultant

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Appendix B

STAKEHOLDER TERMS OF REFERENCE

1. STAKEHOLDER PACKAGE FOLLOWING JUNE 18, 2014 WORKSHOP

This letter provides a summary of the discussions to date regarding the stakeholder based review of FortisBC's system extension policies (the "Project"). It is organized into the following sections:

- Part 1: Request of Stakeholders outlines the request for comments from stakeholders
- Part 2: Background provides a brief history of the Project
- Part 3: Terms of Reference outlines the Project purpose, process, roles and responsibilities, scope and timeline
- Part 4: Guiding Principles outlines the relevant regulatory history along with a summary of the stakeholder feedback in this area
- Appendix contains a list of participants attending the two workshops

PART 1: REQUEST OF STAKEHOLDERS

On June 18, 2014, FortisBC held its second system extension review workshop with stakeholders. As agreed in the workshop, FortisBC has summarized the feedback from stakeholders and is requesting comments before finalizing the terms of reference and guiding principles. This document will then be used to determine the nature of the analysis to be completed in advance of our third stakeholder workshop, tentatively scheduled for October 2014.

Please provide any comments on the document, especially the terms of reference and guiding principles, to mike.metza@fortisbc.com by July 4, 2014.

PART 2: BACKGROUND

In the fourth quarter of 2013, FortisBC met individually with prospective stakeholders. Preliminary support was established for conducting a review of FortisBC's system extension policies in a consultative manner. Stakeholders identified their time constraints and requests were made to schedule the review starting February 2014.

On February 18, 2014 FortisBC held an initial system extension stakeholder workshop. The primary focus of the workshop was to provide stakeholders with a general understanding of current system extension policies and their role in connecting new customers to FortisBC's natural gas distribution system. Throughout the workshop, participants heard from several Stakeholders who spoke to a range of issues such as the different types of new gas customers and their unique and sometimes contrasting needs when it comes to making an efficient energy choice, the challenges faced by off-system communities in meeting their specific energy needs, and a comparison and discussion of the system extension policies of other utilities in Canada and the Pacific Northwest.

A key finding from the workshop was a general consensus among stakeholders that there are gaps in FortisBC's system extension policies in terms of addressing the needs of the different types of customers. Another key finding was the support of a consultative, efficient process for the review of a potential, future application. FortisBC and other stakeholders, including CEC and PIAC, reported how the process followed in 2011 for FortisBC's Gas Supply Incentive and Mitigation Program ("GSMIP") was effective and could serve as a model for engaging stakeholders and pursuing an application with the British Columbia Utility Commission (Commission). In light of these findings, participants agreed to continue with a consultative review of the Company's system extension policies resembling the GSMIP process.

On June 18, 2014, FortisBC held a second system extension stakeholder workshop. Prior to this meeting, FortisBC sent a stakeholder package for comments to help guide the discussion. The purpose of this meeting was to summarize the first workshop, review the terms of reference, and discuss the guiding principles for system extension policies and the deliverables following the workshop.

A list of workshop attendees is found in Appendix A.

Throughout the second workshop, FortisBC summarized feedback it received from stakeholders in advance of the workshop and facilitated the expression of a wide variety of interests. The document that follows captures the views expressed in the second workshop.

PART 3: PROJECT TERMS OF REFERENCE

The following section outlines the terms of reference for the Project, specifically, the purpose, process, roles and responsibilities, scope and timelines.

Purpose

This Project is a stakeholder driven initiative designed to address gaps with FortisBC's current natural gas system extension policies.

Process

The Project workshops will provide a venue to educate stakeholders and solicit their feedback on FortisBC's system extension policies. Recommendations from the Project will form the foundation for a potential application from FortisBC to the Commission. By employing a stakeholder focused approach, the varied interests of stakeholders will be best represented and the Project is expected to be more efficient as a result.

As discussed above, FortisBC is trying to replicate the process used to develop the GSMIP.

Roles and Responsibilities

In the Project, there are four Project roles for participants: facilitator, consultant, stakeholder and Commission Staff.

Facilitator

This role will be fulfilled by FortisBC. In summary, the function of the facilitator is twofold: a) to oversee the manner in which the Project process is carried out; and b) to ensure that the full range of issues is effectively addressed. In conducting the Project, the facilitator will:

- Help to foster an environment of cooperation and trust among participants
- Ensure that all participants have an opportunity to express their views on each issue
- Facilitate the preparation of a proposed Project application which contains all the required components
- Guide the list of issues

The facilitator will attempt to perform the following functions:

- clarifying and summarizing a party's position;
- making explicit any differences in the positions taken by the respective parties;
- recognizing the possible concerns of unrepresented parties;
- encouraging a party to evaluate its own position in relation to other parties by introducing objective standards; and
- identifying options or approaches that have not yet been considered

In the event that FortisBC proceeds with an application to the Commission, FortisBC will be seeking letters of comment and/or support from stakeholders who attended the workshops.

Consultant

This role will be fulfilled by EES Consulting who will provide expertise in the area of system extension policies and related analysis.

Stakeholder

This role will be fulfilled by all parties other than FortisBC, EES Consulting and Commission Staff. Stakeholders have a right to participate in the Project. The responsibilities of this role are as follows:

- Attend workshops and participate in all aspects of policy exploration and formulation
- Represent the views of their constituents
- Review and comment on data analysis and results as needed

Commission Staff

The responsibility of Staff is to ensure that the interests of all affected parties are taken into account. The responsibilities of Staff involved in the Project include the following:

- Supplying factual information that may otherwise not have been brought to the attention of the stakeholders
- Describing possible implications of Project proposals for unrepresented parties; and
- Advising the participants of any precedents recognized by the Commission;

Scope

Included in the Project scope generally is the Companies' current system extension policies and the development of a suitable construct (s) to attach customers, including but not limited to the following:

Customer Types	Description of Customer Type	Current Regulatory Construct	Scope of System Extension Review*
Infill	Customers located within the Companies distribution service territory that requires a service connection to existing natural gas infrastructure already at their location.	Service line cost allowance ("SLCA")	• Identifying a construct to attach infill customers
Main extension ("MX")	Customers who are within a local proximity to the Company's current distribution system and require a main extension to their location before a service connection can be provided.	MX test	• Identifying a construct to attach main extension customers
Off system communities, including First Nations	Customers who require, but do not currently have any natural gas distribution infrastructure within their community.	Certificate of Public Convenience and Necessity ("CPCN")	• Identifying a construct to attach off-system

* Commonalities in the scope of the review across different customer types are as follows:

Time horizon

- Time horizon of any economic test developed
- Forecasting period for new customer attachments

Rate Class

- Treatment of individual customer classes based on rates

Uneconomic Customers

- Contribution in aid of construction ("CIAC") financing
- Contributory thresholds
- Security

Reporting

- Best practices of other peer utilities
- Review of FortisBC's current reporting practices & performance results
- After the attachment model is agreed upon, recommend reporting construct if required.

Timeline

The Project timeline is summarized in the table below:

Date	Event	Topic	Goal	Status
Q4 2013	Individual Stakeholder Consultation	Initial Consultation	Garner Stakeholder support to begin review process.	Complete
February 18, 2014	FortisBC System Extension Stakeholder Workshop #1	Policy Issues	Introduction to current issues and agreement to proceed with exploration of policy alternatives.	Complete
June 18, 2014	FortisBC System Extension Stakeholder Workshop #2	Review of Workshop 1, Terms of Reference & Guiding Principles	Stakeholder feedback on guiding principles will be used to form the foundation of policy options.	Complete
October 2014	FortisBC System Extension Stakeholder Workshop #3	Options Discussion	Review system extension options as developed by Fortis and Stakeholders and opportunity for questions and changes.	TBD
November 2014	FortisBC System Extension Stakeholder Workshop #4	Options Discussion	Continuation of Workshop 3 (as needed)	TBD
Q1 2015	Potential Application	Potential Application	Consideration of potential application to Commission	TBD

PART 4: GUIDING PRINCIPLES

This section is intended to form the initial policy foundation for any future system extension policy enhancements to be considered in the Project. It is organized into three sections covering the following:

- The background on relevant guiding principles from historical Commission proceedings
- The change in market conditions since the most recent Commission proceedings
- Summary of stakeholder feedback on guiding principles

Background

1996 Utility System Extension Test Guidelines

This following list briefly summarizes some of the voluntary guidelines[1] that were developed and issued by the Commission under order G-80-96[2] following a hearing and reconsideration decision on Utility System Extension Tests during the late 1990's.

- Evaluation of system extension should include all benefits and costs over a time period long enough to consider the full impact of the extension.
- System extensions should be evaluated from a social perspective and a utility perspective.
- System extension costs should include pre-construction estimates of the construction costs, system improvement costs, O&M costs, revenues and a reasonable consideration of externalities (for the social perspective evaluation.)
- Utilities should come forward with options for connection fees that send an appropriate signal about the net social costs of less efficient energy use.

2007 Terasen Utilities System Extension and Customer Connection Policies Review Application[3]

The items below highlight some of the key considerations Terasen (now FortisBC) put forward as the basis for the modifications requested in the application. The Companies stated that system extension policies should:

- Signal better value for customers wishing to attach to the system.
- Measure the right factors, be simple to understand and administer with results that send the appropriate economic signal to the customer.

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1 1996 Utility System Extension Test Guidelines – September 5, 1996.
2 British Columbia Utilities Commission Order G-80-96 – August 9, 1996.
3 Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. System Extension and Customer Connection Policies Review Application - July 31, 2007.

- Encourage energy conservation through the test and attachment policies
- Encourage the "right fuel" choice. The Companies believe that natural gas is the appropriate fuel for space and water heating applications and that the connection policies and tests should send the appropriate signal to customers for these energy choices.

The Companies' proposed modifications to its system extension policies were approved under Commission Order G-152-07[4].

Bonbright Principles

The following list of principles has been developed by FortisBC by incorporating system extension issues in the context of the Principles of Public Utility Rates, developed by James C. Bonbright. (Bonbright Principles). Bonbright Principles have been referred to in various applications by the Companies and other utilities. As such, they help by providing a framework for discussing future system extension policy considerations.

• Customer Impact	Considers customer rate impacts of system extensions.
• Fairness:	Ensure fairness between customers in terms of both cost causation and similar treatment over time, recognizing the changes in housing environment, technology and natural gas usage patterns of new and existing customers. Also recognizes the need for fair access for "off-system" communities who require natural gas service.
• Economic Efficiency	Recognizes energy efficiency and conservation at the time of construction for new connections and in the trade-off between main extension policies and rate impacts.
• Stability:	Reflects long-term objectives that will not lead to frequent changes so that customers know what to expect over time.
• Ease of Understandability:	Allows customers to understand the policies and therefore be able to make appropriate choices, as well as making policies easy to administer.

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[4] British Columbia Utilities Commission Order G-152-07 – December 6, 2007

- Competitiveness: Allows for competitiveness of the utility to attract new customers relative to competing gas utilities as well as competing alternative fuels.
- Recovering the Cost of Service: Allows for recovery of utility costs.

Changing Market Conditions

The marketplace has undergone several significant changes since the mid-1990s when system guidelines were developed. These changes and the resulting policy considerations follow.

Natural Gas Supply

Since the time of the development of the original utility system extension guidelines by the Commission in 1996, and a review of system extension policies in 2007, the BC natural gas industry as a whole has undergone substantial change. Supply outlooks reversed from an imminent dwindling of supplies and a scramble to find and import LNG, to today, where BC has now become a leading exporter of natural gas to Canada, the US and global markets with supplies forecast beyond the next 100 years[5]. Prices have gone from a high and volatile to a low and relatively stable environment.

Provincial Government Objectives

During the second workshop, two provincial government objectives were identified:

1. *Environmental considerations related to the Greenhouse Gas Reduction Target Act and the Clean Energy Act*
2. *Economic considerations related to the province's natural gas strategy*

Stakeholders identified challenges in accommodating both objectives in the context of a review of FortisBC's system extension policies. Promoting the most efficient use of natural gas was brought forward as a potential common ground for the two government objectives.

Amalgamation & Rate Design

Stakeholders identified the importance of acknowledging FortisBC moving to a "postage stamp" rate in 2015 and a potential rate design proceeding in 2016. FortisBC indicated that it hoped to proceed with a potential application related to the Project before rate design proceeding occurs.

1.1.1 Guiding Principles

In the second workshop, stakeholders discussed the need for tradeoffs when considering guiding principles as some principles are complimentary while others are contradictory. The

[5] Spectra Energy presentation at PNUCC Power and Natural Gas Planning Taskforce meeting April 11, 2014

following section summarizes the feedback received during the workshop into several main categories.

Protecting Ratepayers

- Relevant benefits, costs and rate impacts of system extension policies should be considered as they relate to new and existing customers

Provide an Energy Choice

- System extension policies need to consider the need for BC residents to fairly and equitably access a variety of energy options.

Consistency with Government Objectives

- System extension policies relating to the domestic use of natural gas need to be consistent with the provincial government's natural gas strategy
- The provincial government's environmental and economic objectives also need to be considered

Recognize First Nations

- The needs of First Nations communities should be recognized

Easy to Understand

The system extension policies need to be easily understood, easy to administer by FortisBC and stable over time for customers

Appendix

Below is a list of FortisBC employees, stakeholders and Staff who participated in the first and second workshops.

Stakeholder	Attendee	Title	Attended Workshop 1	Attended Workshop 2
BC Hydro	**Justin Miedema**	Senior Regulatory Advisor, Rates and Regulatory	**Yes**	**Yes**
BC Hydro	**Kevin Lim-Kong**	Policy Specialist, Customer Interconnections & Policy	**Yes**	**n/a**
BC Hydro	**Frank Lin**	Director, Interconnections and Shared Assets	**Yes**	**n/a**
BC Hydro	**Rena Messerschmidt**	Policy Manager, Customers Interconnections & Policy	**Yes**	**n/a**

Stakeholder	Attendee	Title	Attended Workshop 1	Attended Workshop 2
BC Chamber of Commerce	**Susan Payne**	Executive Director, Ucluelet Chamber of Commerce	**n/a**	**Yes**
BCUC - British Columbia Utilities Commission	**Kristine Bienert**	Acting Director, Policy, Planning and Customer Relations	**No**	**No**
BCUC - British Columbia Utilities Commission	**J Todd Smith**	Acting Director, Infrastructure	**No**	**No**
BCUC - British Columbia Utilities Commission	**Suzanne Sue**	Senior Regulatory Specialist	**Yes**	**Yes**
BCUC - British Columbia Utilities Commission	**Chris Garand**	Engineer, Infrastructure	**Yes**	**Yes**
Chawathil First Nation	**Norman Florence**	Council Member	**n/a**	**Yes**
CEC - Commercial Energy Consumers	**David Craig**	President, Consolidated Management Consultants	**Yes**	**Yes**
EES	**Gail Tabone**	Senior Consultant, EES Consulting	**Yes**	**Yes**
Fortis BC	**Mike Metza**	Energy Products & Services Manager	**Yes**	**Yes**
Fortis BC	**Brent Graham**	Manager, Energy Products & Services	**Yes**	**Yes**
Fortis BC	**Jason Wolfe**	Director, Market Development	**Yes**	**Yes**
Fortis BC	**Dennis Swanson**	Director, Regulatory Affairs	**Yes**	**Yes**
Fortis BC	**Vanessa Connolly**	Government Relations and Public Affairs Manager	**n/a**	**Yes**
Fortis BC	**John Turner**	Director, Energy Solutions	**Yes**	**n/a**

Stakeholder	Attendee	Title	Attended Workshop 1	Attended Workshop 2
Fraser Valley Regional District	**Lloyd Foreman**	Director, Electoral Area A	**n/a**	**Yes**
Fraser Valley Regional District	**Dennis Adamson**	Director, Electoral Area B	**n/a**	**Yes**
MEM - Ministry of Energy and Mines	**Katherine Muncaster**	Acting Director, Energy Efficiency Branch	**Yes**	**Yes**
MJT - Ministry of Jobs, Tourism and Skills Training	**Robert Wood**	Acting Director, Major Investments Office	**n/a**	**Yes**
MLA Boundary - Similkameen	**Colleen Misner**	Constituency Assistant to Linda Larson, MLA	**Yes**	**No (illness)**
Okanagan - Similkameen Regional District	**George Bush**	Board Member	**Yes**	**Yes**
PRRD - Peace River Regional District	**Karen Goodings**	Board Director	**Yes**	**Yes**
PIAC - Public Interest Advocacy Centre	**Tannis Braithwaite**	Executive Director	**Yes**	**Yes**
PNG - Pacific Northern Gas	**Janet Kennedy**	Vice President, Regulatory Affairs and Gas Supply	**Yes**	**Yes**
PNG - Pacific Northern Gas	**Peter Schriber**	Manager, Financial Planning & Business Development	**Yes**	**Yes**
Seabird Island Band	**Brian Titus**	Consultant	**n/a**	**Yes**
Seabird Island Band	**Chief Clem Seymour**	Chief	**n/a**	**Yes**
Yale First Nation	**Steven Patterson**	Natural Resource Manager	**n/a**	**Yes**

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Appendix C

SYSTEM EXTENSION TEST INPUTS TABLE

Forecasted Test Input	Information Source	Explanation	Current System Extension Test Rules	System Extension Test Result	Ratepayer Protection	Real-World Comparison
Number of Attachments	External The builder or developer associated with the project.	Build out plans, civil drawings and registered lot drawings form the basis for the number of attachments. In general, the Company does not "create" the attachment forecast. These drawings are the same ones that would be sent to other utilities and local municipalities. Similar to all other utilities such as hydro and water, it is very difficult for the Company to go into a development after the fact and connect individual homes with natural gas. Therefore the Company must rely on information provided by the builder or developer to install before construction, similar to all other utilities.	Only attachments that occur within the first 5 years can be considered in the test	Understates Benefits	Increased protection for Rate Payer	Attachments can continue to occur on system extensions well beyond the first 5 years and in many cases the system extension test does not capture full scope of a project.
Timing of Attachments	External A function of the economy, predicted by the builder	As stated above, the Company and other utilities rely on information from the customer to define the scope of the project and number of connections. This includes plans as to when an attachment will occur. Any forecast in this regard is difficult to predict given that neither the builder, nor the Company can say they know exactly when a home will be planned, constructed, sold, a customer moved in and finally when that customer choses to call Fortis to activate their meter. All of the unknowns above are also impacted by the housing market and economy which in turn impacts the timing of attachments.	Based on a forecast and project plan provided by the builder, developer or customer.	Neutral	Neutral	Since the test only considers attachments within the first five years and only considers the revenue from those attachments for less than half of their economic life, a discrepancy in the timing of that attachment has no material impact in the real world.
Costs	Internal Known as "geo pricing"	The Company runs annual statistical analysis of regional costs for system extensions and includes dollar per meter values for specific regions. In addition, if a planning and design expert feels that there is a potential for costs to be understated, they have the ability to change the values to more accurately reflect costs.	All costs are included in the test including the main, service meter and regulator	Neutral	Neutral	In some cases a system extension may have higher actual costs and in other cases the costs may be lower. This is a result of the fact that the Company cannot predict exactly what will be found underground or what complication will occur during construction. Overall the aggregate cost variances in the system extension report are around 10%.
Economic Life Span	Policy Fixed as part of the Test	The current system extension test considers revenue and costs over the first 20 years of a new extension.	The economic life-span is fixed for all customers	Understates Benefits	Increased protection for Rate Payer	A system extension has an economic life of 50 years. As such, the current system extension tests considers less than half of the benefits a new customer would bring to the system.

Forecasted Test Input	Information Source	Explanation	Current System Extension Test Rules	System Extension Test Result	Ratepayer Protection	Real-World Comparison
Rates	Internal Fixed	Rate inputs are updated annually. However they remain static within the 20 years the test considers.	Rates are fixed for each of the 20 years included in the test	Understates Benefits	Increased protection for Rate Payer	Rates generally increase over time. The current test assumes all rates remain static for 20 years and therefore the revenue from a new customer is understated. Furthermore, the test does not consider the positive impacts an additional ratepayer brings by expanding rate base and spreading costs over a larger portion of ratepayers.
Use per Customer	Policy Fixed (residential)	For residential customers the use per customer is a function of the appliances they install. The use per customer is calculated based on an average for each appliance. These values have remained static since 2008 and are based on an average of all existing customers.	Fixed for residential based on appliance installations	Neutral	Neutral	Since new appliances are much more energy efficient, by nature they consume less gas. As a result, the Company's forecasts which are based on an average of all customers will always be different than the actual consumption of new customers who have much more efficient homes and appliances.
	Variable (Commercial and Industrial)	Commercial and Industrial customers are sized according to their specific needs. The proper consumption information is usually provided by their mechanical engineer or gas fitter who must ensure that the pressure, meter size and service diameter are designed to specifications.	Variable for Commercial and Industrial based on specific needs.	Neutral	Neutral	The FEU have always used the most up to date information possible to determine the average consumption for existing customers via the Residential End Use Study, as approved by Commission Staff.

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Our File: 23841/0019

July 15, 2014

VIA ELECTRONIC MAIL

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

Attention: Ms. Erica Hamilton, Commission Secretary

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. (FEI) and FortisBC Energy Vancouver Island Inc. (FEVI) 2013 Main Extension and Vertical Sub-Division Reports

We are counsel to the Commercial Energy Consumers Association of British Columbia (CEC). As requested in the Commission's Letter L-34-14 dated June 19, 2014, attached please find the CEC's response with respect to the above-noted matter.

A copy of this letter and attached response have also been forwarded to FEI, FEVI and registered interveners by e-mail.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jlb
Encl.
cc: CEC
cc: FEI
cc: FEVI
cc: Registered Interveners

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)

CEC's Response to BCUC Letter L-34-14

FortisBC Energy Inc. and FortisBC Energy Vancouver Island Inc. 2013 Main Extension and Vertical Sub-Division Reports

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The CEC offers the following response to the questions outlined in British Columbia Utilities Commission (BCUC) Letter L-34-14.

The CEC understands that Fortis has a consultation process ongoing with respect to main extension and service line policies in preparation for a future application to the Commission. The CEC is participating in that process. Fortis has designed this process as a series of workshops. Customer intervener groups are at a distinct disadvantage in this process in that PACA funding is not applicable and the ability to access consultant time and conduct due diligence is absent. The CEC has discussed this issue with Fortis and is awaiting Fortis clarification of verbal assurances that they plan to deal with this issue. The CEC understands that Commission staff and the government representative have been invited to the workshop process and the CEC further understands that the composition of the group invited to the workshops has been determined and designed by Fortis. The CEC has concerns with the pace and nature of the Fortis consultative process. The CEC is prepared to work with the utility to resolve its concerns as stated above.

There are potentially two important phases to the discussion and development of MX policy proposals. These are: (1) a review of the broad principles and alternatives; and (2) the details behind an application for suitable changes to the MX policies. The CEC submits that the Commission may want to determine internally whether or not its own involvement in the process should develop in two stages, being a process to review principles followed by a process to deal with the details or whether or not the Commission is satisfied with the utilities' raising the issues in a single process. The CEC would be comfortable with either a two-step or one-step process. If the Commission chooses alternative means of engaging with the MX process, other than the attendance of staff at the workshops, the CEC would expect to be fully engaged .in whatever processes the Commission may initiate.

1. *What should be the scope and process f or a more detailed review of the Companies' main extension performance and policies?*

The CEC recommends the following scope.

Principles Review:

The CEC recommends that the scope should include:

- Legal framework for expansion of the system
- Utility obligation to serve and its limitations

- Prudence with respect to expansion of the system
- Objectives of the main extension policies
- Appropriate concepts and/o r metrics for evaluation of the success of MX tests
- Assessment of objectives and success criteria
- Applicability of Bonbright principles
- Identify the principles in the existing MX test as a base reference
- Enumerate the relevant principles to be included in the discussion
- Alternatives generated by considering each principle
- Jurisdictional review of the principles and alternatives adopted elsewhere
- Assessment of the advantages and disadvantages for each alternative
- Selection of the principles and alternatives to be evaluated in detail

Detail Review:

The CEC recommends that the scope of a detail review should include:

- Definition of existing and new customers
- Detailed analysis of different customer interests
- Quantitative analysis of existing and new customers including end-use, variability of requirements, rate class issues etc.
- Assessment of the current MX test failures and opportunities
- Responsibilities of developers, initial customers, later customers
- Appropriate incorporation of government policies and plans (municipal, provincial)
- Assessment of each of the alternatives defined in the principles phase:
    - Determination of the threshold and amounts for contribution from new customers
    - Determination of appropriate amounts for utility contribution and justification
    - Appropriate financing from Fortis related to new developments
    - Potential for customers to provide security for the utility financing
    - Measurement and accountability
    - Tariff details
    - Compliance Requirements
    - Costs and benefits
    - Risks
- Selection of appropriate MX policies and detailed methodologies
- Implementation plans
- Communication
- Reporting

With respect to process, the CEC is willing to work cooperatively in either a Fortis or Commission-led process.

2. *Comment on the Companies' security and ratepayer protect ion policies. What changes to these policies should be made, if any?*

The CEC is concerned with ratepayer protection and security policies with regard to extension of the natural gas system.

The CEC submits that changes to these policies should be assessed and determined in the context of appropriate MX principles and detailed analysis. Accordingly, the CEC defers comment until such time as a full process examining MX principles and a review of alternatives has been undertaken.

3. *Comment on the Companies' forecasting performance. What changes to the Companies' forecasting methods should be made, if any?*

The CEC is obviously concerned with the Companies' forecasting performance, and not just in regard to this issue. Prior to assessing changes needed to the Companies' forecasting it will be necessary to determine whether or not forecasting is necessary as part of future MX methodology to be adopted. If forecasting is to be part of an MX test method, the CEC will have more input to this issue at that time.

4. *Comment on the urgency of a review and what the Companies and the Commission should do in the interim?*

The CEC would understand urgency for a review process being defined into two key components: (1) The importance of the review; and (2) the immediacy need for review.

The CEC submits that the MX policies and processes for the Companies are of significant importance. The CEC submits that this importance is to some extent contained by the growth rate for new customers in proportion to the existing customer base. In this context, the CEC submits that the MX issues are one among a number of important issues related to Fortis. The CEC submits that the MX application from Fortis may be scheduled for consideration by the Commission as a matter of convenient planning.

As indicated in the 2013 MX Report and in the Commission discussion, the issues have been extant for a number of years. The CEC is aware of Fortis' proposed timing for its proposed workshop and application process, that being for a Ql, 2015 application. The CEC is not uncomfortable with this sort of timeline. It is difficult to see how any greater sense of immediacy would result in a quicker or more efficient process for resolution of the MX issues.

July 15, 2014 Via Email

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. and FortisBC Energy Vancouver Island Inc.
2013 Main Extension (MX) and Vertical Sub-division Reports

On June 19, 2014, the Commission issued Letter L-34-14, inviting interested parties to provide comments on the following:

1. What should be the scope and process for a more detailed review of the Companies' main extension performance and policies?
2. Comment on the Companies' security and ratepayer protection policies. What changes to these policies should be made, if any?
3. Comment on the Companies' forecasting performance. What changes to the Companies' forecasting methods should be made, if any?
4. Comment on the urgency of a review and what should the Companies and the Commission should do in the interim?

In this response, the Ministry of Energy and Mines (Ministry) will only address questions 1 and 4, that is, it will only speak to the process and not the content of the system extension issue.

The concerns raised by the Commission in L-34-14 are important and require some resolution. However, it is the Ministry's view that the best venue for this is the existing Stakeholder Process on system extension policies which FortisBC has initiated, and the subsequent application process planned by that utility. Page 4-5 of that process' Terms of Reference lists forecasting, security and reporting (including a review of current

…/2

Ministry of Energy and Mines
Electricity and Alternative Energy Division
Mailing Address:
PO Box 9314, Stn Prov Govt
Victoria, BC V8W 9N1
Location:
4th Floor
1810 Blanshard Street
Victoria

reporting practices and performance), all as topics for discussion. The Ministry suggests that the Commission use its representatives in that process to ensure that these topics are addressed to the level of detail that it is satisfied with. L-34-14 outlines the Commission's concerns and can act as a starting point for discussions. If the Commission believes additional sessions or new meeting formats are required, the Commission, or Commission staff, could propose changes to the process. Launching a separate proceeding, in our view, would be duplicative and ultimately cause delay. Although the issues raised in L-34-14 were prompted by forecasting and reporting issues, there is a clear link with system extension policies and any decision in one area would be meaningless without a decision in the other. The Stakeholder Process is slated to conclude by the first quarter of 2015 and aims to achieve stakeholder endorsement, which may ultimately expedite the subsequent application process. In the Ministry's view, the issue is not so urgent that it cannot wait for a considered and inclusive stakeholder process to take place to help inform a Commission decision.

As a participant in the Stakeholder Process, the Ministry is also concerned that having a parallel proceeding will undermine the process. Participants must not feel that the 'real decisions' are being made in a separate forum. It is laudable that FortisBC has chosen to engage stakeholders in a collaborative manner and the Ministry feels that this route should be supported as much as possible.

In sum, the Ministry believes that the most inclusive and streamlined course of action would be to address the issues raised in L-34-14 through the Stakeholder Process currently being facilitated by FortisBC.

Sincerely,

Paul Wieringa
Executive Director, Energy Policy and Regulation
Electricity and Alternative Energy Division

Linda Larson, MLA

Boundary Similkameen

July 15, 2014

<u>Via Email</u>
Commission.Secretary@bcuc.com

Ms. Erica M. Hamilton, Commission Secretary
British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton,

<u>Re: FortisBC Main Extension (MX) L-34-14 Registered Intervener Reply</u>

As MLA for the Boundary-Similkameen I take my job seriously and do everything I can to be a voice for my constituents from all walks of life regardless of income, location or political beliefs. I have staff that are well-versed in dealing with the day to day operations of a Constituency Office and also take their jobs seriously.

Last fall, during a meeting with my Senior Constituency Assistant, Colleen Misner and FortisBC, it became very apparent that the need for natural gas in our communities is critical. We had asked for a meeting because our riding is quite large and a portion of it does not have access to affordable alternate energy.

People are literally having to choose between “eating or heating” due to the 2-tired (conservation) rate structure for electricity recently implemented by FortisBC and approved by the BCUC. Over the winter months, our office was deluged by calls, emails and letters from people who live in older mobile homes, seniors fixed incomes, and people living in homes that they simply cannot afford to upgrade. Many of them have no choice but to use electricity for heat and it is breaking them.

Our comments and the letters shared to both FortisBC and the BCUC are a true testimony of what is happening in the “real world”. This discussion led to our being asked to participate as interveners for the System Extension Workshops (MX) being held by FortisBC. We were thrilled to be asked because we feel that it is an important issue that needs to be addressed, assessed and “fixed” as soon as possible to ensure that all British Columbians living in areas without access to alternative sources of power get that access.

After two sessions, while we are still trying to understand all of the technicalities, we feel that some headway is being made and are eager to continue to participate.

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Province of
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Constituency Office
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Linda Larson, MLA

Boundary Similkameen

In your recent letter (L-31-14) you ask four specific questions. Questions that we may not have all of the answers (or the ability) to give you qualified responses to. You also imply you are considering a parallel process of your own while there is already one in place. Would we also be asked to participate? In fact, we feel that by being deliberately left off the list of interveners who received your letter, that you are trying to cut us out completely from participating in this series of workshops and that if you were to hold your own, there would be no voice left in the room to speak on behalf of our taxpayers- the taxpayers who pay your salaries.

What we do know this: There is already a process in place by way of these workshops that seems to be working. Why on earth would anyone, including the BCUC <u>not</u> want to continue in their effort towards making this project a success? A lot of time, money and effort has been spent by all who are participating, and we feel that the remaining part of this initiative should be completed.

It means a great deal for us to be a part of this process, so please allow us to continue to participate in it. Meanwhile, we'll leave it to the experts to answer your more technical questions, and urge you to consider moving forward with this. We will be very disappointed if the BCUC decides not to go forward to help resolve this issue. We respectfully ask that we be copied on any further correspondence so we are not "left in the dark".

Sincerely,

Linda Larson

Linda Larson, MLA
Boundary-Similkameen

Cc: Brent Graham, Manager, Energy Products and Services, FortisBC

Legislative Office
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Barristers & Solicitors

July 15, 2014

VIA E-MAIL

Erica Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor - 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

**Re: FortisBC Energy Inc. and FortisBC Energy Vancouver Island Inc.
2013 Main Extension (MX) and Vertical Sub-division Reports**

We are counsel for the BC Old Age Pensioners Organization, BC Coalition of People with Disabilities, Tenants Resource and Advisory Centre, Council of Senior Citizens Organizations, and Active Support Against Poverty (collectively, "BCOAPO") in BC Utility Commission Proceedings involving the Fortis Gas Utilities. We make the following comments in response to the four questions posed in Commission Letter L-34-14 dated June 19, 2014.

1. **What should be the scope and process for a more detailed review of the Companies' (FEI and FEVI) main extension performance and policies?**

BCOAPO agrees that the Companies' main extension test requires a detailed review. To this end, BCOAPO is participating in a consultative process initiated by the FortisBC Energy Utilities. The terms of reference for this process are attached as Appendix B to the FortisBC Energy response letter dated July 9, 2014. Although discussion at the two stakeholder meetings held to date has been quite high level, several significant issues have been raised, including:

- the design of the current test;
- calculation of extension costs;
- the number and timing of attachments;
- use of the existing average UPC for new customers;
- the time periods used for calculation of the profitability index;
- the further extendibility of new mains;
- provincial GhG reduction policy;
- contributions in aid of construction;
- developer costs and security.

We also note that Commission staff are participating in the stakeholder consultation, along with representatives of the Province, ratepayer groups, First Nations and non-connected communities. This gives the Commission the opportunity to raise issues in the consultation process that it believes are significant, and to ensure these issues are addressed as fulsomely as is feasible in a consultative setting.

It is not yet clear whether the consultation process as designed will enable the parties to come to grips with the detailed, technical aspects of the main extension test. In addition, the stakeholders assembled clearly represent diverse interests (e.g., existing ratepayers versus non-connected communities) which may make it impossible to reach a consensus decision on changes to the test. To a very large extent, the MX test must be designed to meet objectives. Without agreement on objectives, we are unlikely to reach agreement on the test itself. That said, BCOAPO supports continuing with the existing process (as proposed or as modified by Commission direction), with Fortis filing an application of proposed changes to the MX test in early 2015.

2. **Comment on the Companies' security and ratepayer protection policies. What changes to these policies should be made, if any?**

3. **Comment on the Companies forecasting performance. What changes to the Companies forecasting methods should be made, if any?**

Commission questions 2 and 3 are interconnected. BCOAPO does not object to s.12.6 of the Companies General Terms and Conditions, which provides for Contributions in Aid of Construction when the profitability index falls below specified levels. However, in our view, the use of existing average UPC as a proxy for the future average UPC of new customers is inaccurate and inappropriate. Adding efficiency credits for the installation of high efficiency appliances exacerbates this inaccuracy. This creates inaccurate profitability ratings for new connections and means Contributions in Aid of Construction are likely not being made in all cases where prudence requires. BCOAPO is also of the view that whether to charge a security deposit where the financial viability of the extension is uncertain should not be within the Companies' sole discretion. Rather, some Commission approved criteria should be put in place to determine when a security deposit will be required.

It is worth noting, however, that several aspects of the main extension test other than security/ratepayer protections and forecasting accuracy also need to be revisited in this process. Accordingly, BCOAPO prefers to see a more fulsome review with input from stakeholders on a variety of issues including, for example, the time lines used for calculating the value of new attachments and infrastructure lifespans.

4. **Comment on the urgency of a review and what should the Companies and the Commission do in the interim?**

BCOAPO notes that the existing main extension test has been in place for a number of years. The financial crisis of 2008-2009 created highly unusual circumstances which are only now the subject of MX reports. In our view, it is the circumstances of 2008-2009 and the extreme mismatches that resulted between forecasts and actuals in those and immediately subsequent years which have created the current sense of urgency. We are not likely to see a repeat of those circumstances prior to 2015, when the current consultative process has run its course. Consequently, we do not view the current situation as urgent.

However, BCOAPO does welcome a higher level of Commission participation in the consultative process, including potentially a requirement that the process address a list of specified issues that the Commission views as significant. BCOAPO's other concern with the existing process, as noted above, is its potential inability to address the detailed technical aspects of the test or to reach a consensus on the test's objectives given the diverse interests involved.

Please do not hesitate to contact me should you have any further questions.

Yours truly,
BC PUBLIC INTEREST ADVOCACY CENTRE

Tannis Braithwaite
Executive Director
Barrister & Solicitor

c: FEI
FEVI
Registered Interveners

William J. Andrews

Barrister & Solicitor

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July 15, 2014

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC, V6Z 2N3
Attn: Erica Hamilton, Secretary
By email: Commission.Secretary@bcuc.com

Dear Madam:

Re: FortisBC Energy Inc. (FEI) and FortisBC Energy Vancouver Island Inc. (FEVI) 2013 Main Extension (MX) and Vertical Sub-division Reports, Letter L-34-14

This is on behalf of the B.C. Sustainable Energy Association and the Sierra Club British Columbia in response to the Commission's Letter L-34-14 inviting comments on the scope and process for a review of the Companies' main extension performance and policies.

BCSEA-SCBC have had the opportunity to review FortisBC's July 9, 2014 letter proposing, in summary, that the Companies' existing consultation process should continue to completion prior to any Commission review of MX performance and policies.

At a high level, BCSEA-SCBC are wary that what the FEU describe as "the inability of the system extension test to recognize the full benefits associated with connecting a new customer" [p.2] not become a basis for artificially reducing main extension contributions in order to promote load building on the natural gas system. However, BCSEA-SCBC are not sufficiently informed to be able to provide detailed comments to the Commission concerning the content of the FEU MX performance and policies at this time.

In general, BCSEA-SCBC support the concept of utilities conducting stakeholder consultation prior to Commission proceedings. To confirm, BCSEA-SCBC have not been participants in FEU's ongoing MX consultation process. However, BCSEA-SCBC would participate in the Companies' MX consultation process if it continues. BCSEA-SCBC do not oppose the Commission allowing a reasonably short period of time for the FEU to complete the MX consultation, prior to the Commission reviewing this important topic. An application by the Companies may be the most productive format for the Commission's proceeding.

Yours truly,

William J. Andrews

Barrister & Solicitor

cc. Distribution List by email

-----Original Message-----
From: Lloyd Forman
Sent: July 14, 2014 14:44
To: commission.secretary@bcuc.com
Subject: reference L-34-14

Congratulations to the P.U.C. and to Fortis for working to-gether to meet the objective of the best possible service that can be offered to the public.
As I laboured through the mountain of information there is a couple of thoughts that dominate and I would like to share them.

--Rules must have a reasonable marriage to reality--or they are doomed.

--Forecasting is what the weather man does and if we focus on a short time span they are probably correct 50% of the time.
Over the long term the mean average is fairly predictable by just being fractionally different.
Business has to look at the bigger picture and the protectors of the public must also look at that level to best serve the public;

In conclusion I congratulate the P.U.C. but also am strongly in favour of the Fortis application.

I have had decades of business experience also decades of local government experience which I believe gives me a reasonable marriage towards my approach on business realities and regulatory practices

Respectfully,

Lloyd Forman

PEACE RIVER REGIONAL DISTRICT

Office of: Electoral Area 'B' Director

via email: Commission.Secretary@bcuc.com

July 22, 2014

Ms. Erica M. Hamilton
Commission Secretary
BC Utilities Commission
6th Floor – 900 Howe Street,
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC main extension 1-34-14

Please accept by apology for missing your deadline of July 15, 2014 and please accept this email even though it is late. I am submitting this as the Director for Electoral Area 'B' of the Peace River Regional District. I have held this position continuously for the past 26 years and my intent has always been to work toward improving the infrastructure that supports the rural and remote people working and living in the north. Of all infrastructure needs, access to natural gas is at the top of our list.

I have attended the first two Stakeholder Engagement sessions, sponsored by FortisBC and have appreciated hearing the comments made by everyone at the table. I look forward to any future discussions that may be scheduled. It is my sincere hope that the process initiated by FortisBC is allowed, in fact, encouraged to continue and that all the interested parties, including the BCUC, will be available and in attendance. I look forward to receiving any future correspondence from all the participants on this important initiative.

The ability to utilize the natural gas resource, which is our resource, is of paramount importance. Access to this resource has a huge economic spinoff for the residents, the region and the Province. It can mean the difference in the viability of any new business. Much of what creates the energy for this region and the province is in more remote areas where there may not be the number of customers needed to qualify under the present main extension tests.

…/1

PLEASE REPLY TO:
■ BOX 810, DAWSON CREEK, BC VIG 4H8 TELEPHONE: 250) 784-3200 OR (800) 670-7773 FAX: (250) 784-3201
EMAIL: prrd.dc@prrd.bc.ca
☐ 9505 – 100th Street, Fort St. John, BC V1J 4N4 Telephone: (250) 785-8084 Fax: (250) 785-1125
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In order to have a quality of life, improve the economic development of the local residents and industry including agricultural endeavours, it is of utmost importance to have our regulatory body work with the companies and the people to determine a formula that recognizes the pipe in the ground in this area has a lifespan of 25 – 50 years before it needs to be replaced and that any formula that is derived needs to measure whether access to the natural gas resource is one that will pay its way in a timely measure so as not to be a burden on the balance of customers in the system.

We must measure the value over an extended period of time and recognize that with the clean energy criteria, natural gas is much preferable to the use of propane, diesel, wood or coal to our air quality.

I believe that the main extension formula must be broad enough to meet the demands of every region of the province, especially those area such as the Peace, where the natural gas is produced.

I leave the answer to your technical questions to those who are much more qualified than I. On behalf of rural communities across the region and the province all we really ask is GIVE US A CHOICE. Develop a regulatory extension test that has an extended time frame to pay back the costs and then let US make the decision as to whether it is affordable.

Sincerely,

Karen Goodings

Karen Goodings
Director, Electoral Area 'B'
Peace River Regional District

c.c. – Brent Graham, Manager, Energy Products and Services, FortisBC
brent.graham@fortisbc.com

From: Wood, Robert B JTST:EX [mailto:Robert.Wood@gov.bc.ca]
Sent: July 14, 2014 2:22 PM
To: Commission Secretary BCUC:EX
Cc: Graham, Brent
Subject: Letter L-34-14

Ms. Erica M. Hamilton, Commission Secretary ,

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

I would like to take the time here to express my appreciation of the FortisBC System Extension Stakeholder engagement process. This process seems to be working well to provide better information upon which Fortis can build an improved Main Extension Test. I have reviewed your letter to Fortis dated June 19, 2014 and concur that it is important to ensure main extensions are financially viable or subsidized by the companies. I feel that Fortis should be granted the opportunity to propose improvements based on their existing data and the work of this stakeholder group.

In our role supporting major investors looking to establish projects in BC, natural gas availability and affordability is vital, and we often call upon Fortis and other BC utilities for information and support.

I thank you for your attention.

Regards,

Rob Wood
A/Director, Major Investments Office
Ministry of Jobs, Tourism & Skills Training
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Janet P. Kennedy
Vice President, Regulatory Affairs & Gas Supply

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Via E-Mail

July 15, 2014

B.C. Utilities Commission
6th Floor - 900 Howe Street
Vancouver, B.C.
V6Z 2N3

File No.: 4.2 (2014)

Attention: Erica Hamilton
Commission Secretary

Dear Ms. Hamilton:

Re: <u>FortisBC Stakeholder System Extensions Review Process</u>

The purpose of this letter is to advise the Commission that PNG has received a copy of the letter dated July 9th, 2014 filed by Fortis BC Energy group of companies in response to the Commission Letter L-34-14. PNG would like to note that it has been attending the stakeholder engagement and consultative process workshops on the review of the System Extensions Policies being led by FortisBC and plans to continue to participate in this process. PNG supports FortisBC's efforts to engage stakeholders through open consultation in reviewing its system extension policies to achieve a positive outcome in an effective and efficient manner.

Please direct any questions regarding this letter to my attention.

Yours truly,

Janet P Kennedy

J.P. Kennedy

ERICA HAMILTON
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
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BRITISH COLUMBIA UTILITIES COMMISSION

LETTER L-44-14

SIXTH FLOOR, 900 HOWE STREET, BOX 250
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TELEPHONE: (604) 660-4700
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VIA EMAIL
gas.regulatory.affairs@fortisbc.com

August 22, 2014

Ms. Diane Roy
Director, Regulatory Affairs - Gas
FortisBC Energy Inc.
Surrey, BC V4N 0E8

Dear Ms. Roy:

Re: FortisBC Energy Inc. and FortisBC Energy Vancouver Island Inc. (Companies)
Comments Received on the Companies'
2013 Main Extension (MX) and Vertical Sub-division Reports

The British Columbia Utilities Commission (Commission) writes in response to comments received on Letter L-34-14.

The Commission has reviewed the comments and is supportive of the Companies' efforts to consult stakeholders prior to submitting an application. The Commission encourages the Companies to continue with and complete their current consultation process in a timely manner. The Commission expects the Companies to continue working with stakeholders and Commission staff to develop and review a detailed terms of reference, address the concerns raised by the Commission in Letter L-34-14, and file an application for revised main extension policies in the first quarter of 2015. The concerns raised by the Commission in Letter L-34-14 include but are not limited to: 1) the forecasting accuracy of main extension costs, number of attachments, timing of attachments and use per customer, and 2) the application of efficiency credits, contributions in aid of construction, and security deposits.

To support a timely process, the Commission requests the Companies to confirm by December 31, 2014 that they will be filing an application on their main extension policies by March 31, 2015, or the Companies must provide an explanation and justification why they are not, also by December 31, 2014. If the Companies do not commit to filing an application that addresses the Commission's concerns by March 31, 2015, the Commission will establish a process to address the Commission's concerns with the current main extension policies.

The Commission confirms that Commission staff will be assigned to participate in the stakeholder process to develop and review the detailed terms of reference and ensure the Commission's concerns are fully considered. Active participation by Commission staff does not constitute the Commission's support of a future main extension application, nor does it limit the Commission's ability to fully investigate a future application.

Yours truly,

Erica Hamilton

CG/cms
cc: Registered Interveners and participants in the FEU MX workshops:
FBC-PBR-2014-18-RI; FEI-PBR-2014-18-RI; TGVI-TGI-SyX&CPR-RI

Diane Roy
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December 19, 2014

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI) and FortisBC Energy Vancouver Island Inc. (FEVI) (collectively the Companies) System Extension and Customer Connection Policies Application (the Application)

Response to Letter L-44-14

On August 22, 2014, the British Columbia Utilities Commission (the Commission) issued Letter L-44-14 in support of the Companies' efforts to consult stakeholders prior to submitting an Application, and encouraged the Companies to continue with and complete the consultation in a timely manner. In Letter L-44-14, the Commission also requested confirmation that a System Extension and Customer Connection Policies application will be filed by March 31, 2015. If such confirmation is not provided, the Companies are required to provide justification, by December 31, 2014, as to why not.

The Companies are committed to a timely, consultative process for submitting the Application related to the system extension policies, as many stakeholders have been anticipating an expedient update of the Companies' policies to make it easier to access natural gas. To date, the Companies have met individually with stakeholders and have led four system extension review workshops to solicit input from a wide cross section of stakeholders with varying knowledge and interests. Further, the Companies respectfully submit that they have met the expectations of the Commission set forth in Letter L-34-14 by successfully developing detailed terms of reference and addressing with stakeholders the concerns brought forward by the Commission in Letter L-34-14. Both of these items will be included in the Application. The majority of the feedback received following the most recent workshop indicates support from stakeholders for the recommendations put forward by the Companies. There was also considerable discussion on matters of provincial policy with respect to attaching new customers and in particular new communities. Additional discussions with key stakeholders will be required prior to filing the Application to clarify the role of government as it relates to natural gas system extension policy.

Pursuant to Order G-152-07 (FEI-FEVI Main Extension (MX) Report) and Order G-6-08 (FEI Vertical Subdivision Report) the Companies are required to file Annual MX reports at the end of the first quarter of each year. Commission Staff at the most recent workshop also noted that these reports are required to be filled annually irrespective of any System Extension Application. These reports involve and consume significant resources to collect and compile the required data. For the 2014 MX report, there are also further reporting requirements resulting from correspondence with Commission staff related to previous year reports. These reports utilize the same staffing resources of the Companies that would be used to compile and file the Application.

As a result of these resource constraints and challenges, the Companies will be unable to complete both the 2014 MX report and file the Application by March 31, 2015. The Companies will submit the 2014 MX report by March 31, 2015, as required under Orders G-152-07 and G-6-08. At this time, the Companies anticipate being in a position to submit the Application in the second quarter of 2015. The Companies will notify the Commission should circumstances arise affecting this anticipated timing.

If further information is required, please contact Mike Metza at 604-592-7852.

Sincerely,

FORTISBC ENERGY INC.

Original signed by: Ilva Bevacqua

For: Diane Roy

cc (email only): Workshop Participants

ERICA HAMILTON
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

LETTER L-6-15

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VIA EMAIL
gas.regulatory.affairs@fortisbc.com

February 20, 2015

Ms. Diane Roy
Director, Regulatory Services
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Ms. Roy:

Re: FortisBC Energy Inc. and FortisBC Energy Vancouver Island Inc. (Companies or FEI)
System Extension Application Timing - Response to Letter L-44-14

On August 22, 2014, the British Columbia Utilities Commission (Commission) issued Letter L-44-14 requesting the Companies confirm by December 31, 2014 that they will be filing an application on their main extension policies by March 31, 2015, or the Companies must provide an explanation and justification why they are not, also by December 31, 2014. The Commission explained that if the Companies do not commit to filing an application by March 31, 2015 that addresses the Commission's concerns, it will establish a process to address the Commission's concerns with the current main extension policies.

On December 19, 2014, the Companies filed a letter informing the Commission that the Companies will be unable to complete both the 2014 Main Extension (MX) report and file the application by March 31, 2015. The Companies explained that the 2014 MX report utilizes the same staffing resources that would be used for the application. The Companies submit they will file the 2014 MX report by March 31, 2015, and anticipate being in a position to file the application in the second quarter of 2015. The Companies submit they will notify the Commission should circumstances arise affecting this anticipated timing.

The Commission is satisfied with the explanation provided and extends the deadline for filing the application to June 30, 2015. If FEI does not file an application that addresses the Commission's concerns by June 30, 2015, the Commission will establish a process to address the Commission's concerns with the current main extension policies.

Yours truly,

EHamilton

Erica Hamilton

CG/cms

cc: Registered Interveners and participants in the FEU MX workshops:
FBC-PBR-2014-18-RI; FEI-PBR-2014-18-RI; TGVI-TGI-SyX&CPR-RI

Appendix D

2014 MAIN EXTENSION REPORT AND SLCA ANALYSIS

Diane Roy
Director, Regulatory Services

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March 30, 2015

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI) and FortisBC Energy (Vancouver Island) Inc. (FEVI) (collectively the Companies) 2014 Year End Report for:

- **FEI-FEVI Main Extension (MX) Report – British Columbia Utilities Commission (the Commission) Order No. G-152-07 Compliance Filing; and**
- **FEI Vertical Subdivision Report – Commission Order No. G-6-08 Compliance Filing**

The Companies respectfully submit the attached 2014 MX Report. In addition to reflecting the format and methodologies utilized in the previously approved MX Reports, the Companies believe the 2014 MX Report continues to comply with Orders G-152-07 and G-6-08.

As stated in the attached 2014 Report, the Companies believe that the main extension reporting methodology has significant limitations. To address these limitations, the Companies will include a proposal for a new reporting methodology for evaluating the success of a main extension as part of a System Extension Policy Review Application. In accordance with Letter L-6-15, the Companies intend to file the application by June 30, 2015.

If further information is required, please contact Mike Metza at 604-592-7852.

Sincerely,

FORTISBC ENERGY INC. and
FORTISBC ENERGY (VANCOUVER ISLAND) INC.

Original signed by: Dennis Swanson

For: Diane Roy

Attachment

FortisBC Energy Inc.

Main Extension Report for 2014 Year End

Compliance Filing in Accordance with Commission Orders G-152-07 and G-6-08

March 30, 2015

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EXECUTIVE SUMMARY

The Main Extension (MX) Report for 2014 from FortisBC Energy Inc. (FEI or the Companies when referencing to both FEI and FortisBC Energy (Vancouver Island) Inc.)[1] and the FEI Vertical Subdivision (VSD) Report for 2014 Year End (collectively referred to as the 2014 MX Report or the Report) are filed in accordance with British Columbia Utilities Commission (BCUC or Commission) Orders G-152-07 and G-6-08.

The primary findings in the 2014 MX Report are summarized below:

1. The Companies are in compliance with the Commission's reporting directives

The 2014 MX Report complies with and contains the requisite information in accordance with the reporting requirements as set out in Orders G-152-07 and G-6-08. In addition, the Report provides further information requested in Letters L-67-11, L-19-12 and L-60-12. The 2014 MX Report follows the format and methodologies requested by the Commission and employed in previous MX reports.

2. The Profitability Index (PI) thresholds should remain unchanged until the completion of the MX test policy review process

The Companies believe that the existing PI threshold of 1.1 for the aggregate main extensions and the minimum PI threshold of 0.8 for individual main extensions should remain unchanged until the completion of the MX policy review process, which is contemplated to begin later in the year. By Letter L-6-15, the Companies are to file an application regarding MX policies (MX Application) by June 30, 2015.

3. The MX test results as reported are not appropriate mechanisms to evaluate the final economic impact of a main extension on ratepayers

The Companies have included one additional section in the Report on the use of the MX Report to evaluate whether a main extension is economic. In the opinion of the Companies, the MX Report should not and cannot be used to determine the past economic performance of a main. The use of the MX test as a reporting tool, as well as the information requested by Commission staff for the MX report, has limitations, as the MX test was designed to evaluate whether or not a main extension was economic (or meeting certain profitability index threshold) at the time a main extension was planned based on a set of forecast parameters. The MX Report, which reports on such MX test results, cannot be used as a tool to evaluate the past performance of main extensions. The MX Report can be used to view actual construction costs, actual consumption and actual attachments. Any further use of, or conclusions drawn from, the MX Report, would not be appropriate.

[1] On December 31, 2014, FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. were amalgamated. The amalgamated entity carries on the business under the name of FortisBC Energy Inc. However, this Reports results in Main Extension results in 2014, the results for FEI and FEVI are separately reported as in the previous years.

1. MX REPORT OVERVIEW

The 2014 MX Report is organized in the following manner:

- Section 2 discusses the limitation of using the MX test and MX reporting in determining the final impact of a main extension on ratepayers.
- Section 3 provides a brief review of the Companies' System Extension Stakeholder Workshops which took place throughout 2014.
- Section 4 provides a description of the MX test and parameters.
- Section 5 provides an outline of the MX forecasting methodologies.
- Sections 6-10 provide the results.

1.1 *REPORTING HISTORY*

All tables and methodologies contained in the 2014 MX Report are reproductions of previously agreed upon templates initially provided by Commission staff, subsequent to and in addition to requirements set out in Commission Orders G-152-07 and G-6-08. A detailed discussion on the recent MX reporting requests from Commission staff, which forms the structure of this Report, as well as a full review of the regulatory history, can be found in Section 2 of the 2012 FEI and FEVI Main Extension Report. A full listing of correspondence related to the structure and requirements for the MX Report can be found in Appendix D.

Table 1-1 below provides reference to the reporting requirements from the pertinent Commission orders contained within the 2014 MX Report.

Table 1-1: Compliance Reporting Requirements Met by the Companies

Order Number	Compliance Reporting Requirement	Report Page Reference #
G-152-07	Provide schedules comparing the existing and updated geo-codes and MX Test input parameters.	p. 26-28
G-152-07	Update FEVI MX test to reflect FEVI use per appliance.	p.27
G-152-07	Reflect in the Companies' MX tests their experience of the consumption ramp-up in the early months of service.	p.29-134
G-152-07	Comparison of forecast and actual costs, consumption and PI for the first five years of main extensions in the sample.	p.29-134
G-152-07	A concise explanation of the random sampling method used.	p.24
G-6-08	Confirm that it reflects, in the MX test inputs, the fact that larger developments may require several years before all units are occupied an normal consumption patterns are established.	p.29-134
G-6-08	The results of FEI's main extension tests to Vertical Subdivisions.	p.29-134

1.2 *MX REPORTING IN COMPLIANCE*

As demonstrated in Table 1-1, the Companies are in full compliance with the reporting directives from Commission Orders G-152-07 and G-6-08. In this Report, the Companies also went beyond the requirements from Commission orders, by

- Including additional information as requested in Letters L-67-11, L-19-12 and L-60-12; and
- Following the reporting approach and populating information in data tables designed by Commission staff.

2. LIMITATION OF MX TEST AND MX REPORT AS AN EVALUATION TOOL OF MAIN EXTENSION PROFITBILITY

This section outlines the limitations of the current MX reporting approach as a means to evaluate the profitability of a main. In Order G-152-07, the Companies are required to report on "PI for the first five years of main extensions…." In Letter L-34-14, the Commission focused on the 2008 FEI and FEVI aggregate main extension PI results from the 2013 MX Report to highlight its concerns that ratepayers may be exposed to an undue cost burden resulting from uneconomic customer connections[2]:

> *"The Commission is concerned that the 2008 aggregate PI results over the five year period were below 1.0, indicating that existing ratepayers might be exposed to an undue cost burden…"*

While the reported 2008 aggregate PI results were below 1.0, the Companies do not believe that the unfavourable PI results as reported in the MX Report are a reliable indication that the customer connections are in fact uneconomic. The Companies respectfully submit that the MX Report of past PI results does not provide information from which the Commission can determine whether the main extensions that have been installed during the five year period are economic or have exposed existing ratepayers to an undue cost burden. In brief, the PI results from the MX test do not reflect the past economic performance of a main, because the MX test is designed to evaluate the potential economic performance of a main extension at the time of installation based on a set of forecast parameters. The MX test reflects a point in time value. A report of the MX test results that essentially preforms a re-forecasting of PI results from the MX test does not provide a reliable means to assess the past economic performance of a main or its impact on ratepayers.

These will be further explained below.

2.1 *MX Report*

The MX Report reports on the actual costs to install a main, the actual customer attachments and the actual consumption volume. This information is useful in understanding if costs incurred were in line with forecast, the number and timing of customer attachments and if consumption of new customers is similar or different from existing customers.

However, re-running the MX test to create a new forecast PI does not provide meaningful information, as will be further explained below.

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2 BCUC Letter L-34-14 issued June 19, 2014, p.2.

2.2 *INTENDED USE OF THE MAIN EXTENSION TEST*

The MX test is a tool that was developed to determine if the Companies can connect a customer economically. It is a *planning tool* to assess whether a main extension is economic; that is, existing customers should not be exposed to an undue cost burden as a result of the expansion of the distribution system to attach new customers as planned and new customers should not be exposed to an undue cost burden or unduly subsidize existing customers when connecting. The test considers the relationship between revenues and costs (otherwise known as a Profitability Index or PI). The PI results are used to determine how much the Companies can invest given the revenue expected from the customer. The value of the asset that the Companies will invest in may be considered a "credit" to the customers that is put toward the utility investing in assets. If the revenue is less than the costs (or if the credit is not large enough to cover costs), the customer must contribute financially to the system.

The test was arrived at through a number of regulatory proceedings. Through those proceedings, the parameters of the test were agreed upon and/or directed. In other words, the parameters of the test that determine the investment value by the Companies are a result of a "give and take" or "back and forth" between parties through the regulatory process. The parameters that the test uses are a set of forecasted factors/figures, such as the customer's natural gas rate, depreciation period, discount rate, and overhead, as well as forecasted customer attachments and costs. These data/parameters are information forecast at the time of the MX test is run, usually when the Companies considers or evaluates a planned main extension.

The test, based on forecasts as discussed above, generates a PI that accordingly reflects a value at a point in time. As mentioned above, it determines what credit the customer will receive. If this credit does not cover the costs, then the customer is requested to make a contribution towards the installation of the main extension. The intent of the MX test is thus met.

2.3 *LIMITATIONS OF MX TEST*

Because the MX test produces a PI that reflects a result/value at a point in time, it has limitations.

- The MX test is not designed to determine the eventual profitability of a main or the financial impact of a main on ratepayers. As mentioned above, the data/parameters used in the MX test are forecast information at a *point in time*. This information is used to determine what credit the customer will receive to attach to the system. The information gathered at the time the test is run can and does change over time. For example, the consumption used in the test to determine the "credit" can end up being greater or less than what was originally forecast. Other parameters, such as actual natural gas rates, overheads and taxes over the life of the asset, actual consumption, and actual attachments are not known at the time the test is run. These parameters can only be truly known at the end of the useful life of the asset (main).

- The MX test is based on a forecast, which is an educated and best effort estimate of certain events that may happen in the future. Because it is a forecast, it is inherent that there will be differences between the forecast and what actually occurs.

2.4 *MX REPORT NOT A TOOL FOR EVALUATING PAST PERFORMANCE OF MAIN EXTENSIONS*

In the decision accompanying Order G-152-07, the Commission requested annual reporting on the "PI for the first five years of main extensions." Based on the Companies' past few years' experience of reporting and the discussions the Companies had with Commission staff, the MX reporting has become an exercise of re-forecasting of PI results from the past five years. Given the intended use of the MX test as discussed above, the Companies submit that reforecasting of an original point in time forecast, which also occurs at a point in time, does not give results that are reliable in evaluating whether ratepayers that existed at the time of the original test might be exposed to an undue cost burden. This section provides a brief summary of the specific limitations of MX reports that use the PI results from the MX test and the Modified MX Test (explained below).

2.4.1 Reporting a Form of Reforecasting

Order G-152-07 required that the Company report annually on its main extensions. This was the first time a utility in BC was required to report annually on its extension activities, and as such there was no generally accepted form of main extension reporting in BC. Based upon the wording in Order G-152-07, and in subsequent discussions with Commission staff, the form of reporting has become an exercise of re-forecasting the original main extension forecast.

In more recent MX reports, the Companies were requested by the Commission to change parameters within the MX test and then re-forecast the results of the original MX Test forecast (the Company has termed this the "Modified MX Test"). All reports and tables following this section use the "Modified MX Test" using the Commission staff provided information and parameters.

As discussed in section 2.1 of this Report, the MX reports have provided some useful information. However, the reports that essentially perform a re-forecasting of PI results as mentioned above do not fulfill the purpose of determining the past economic performance of a main extension or indicate that ratepayers might be exposed to an undue cost burden. In other words, comparing one MX Test forecast results to another MX Test forecast results, which is the essence of the Modified MX Test, does not accurately demonstrate whether the Companies are attaching customers economically. Unfortunately, the MX reporting has been used in this manner for the past number of years.

2.4.2 Further Shortfalls of the MX Reporting Requirements

In the decision accompanying Order G-152-07, the Companies were required to compare "forecast and actual cost, consumptions, and PI for the first five years of main extensions." While the reporting of costs, attachments and consumption is appropriate for informative purposes, the discussion below details some of the specific challenges of a MX report that uses the MX test as an evaluation tool rather than its intended purpose as a planning tool. Primarily, this section demonstrates how an exercise of forecasting and reforecasting cannot provide a reliable tool to evaluate whether a main extension will expose ratepayers to undue financial hardship during the life of the main.

2.4.2.1 MX Report Reporting Window

The forecasted MX Test does not account for any activity which may occur after the first five years when determining the "credit" to the customer at the time of the attachment. Many attachments that occur on a main can occur after the five year reporting window. As a result, the actual attachments outside of the five year window would not be included the re-running of either the MX Test or Modified MX Test in the MX Report.

2.4.2.2 MX Test Asset Life

The MX test uses a discounted cash flow calculation over a 20 year asset life. The twenty year period represents less than one half of the expected useful life of a main[3] and therefore the results of the test are not representative of the useful life of the asset.

2.4.2.3 MX Test Rates

The MX test assumes that the rate a customer pays for gas remains constant for the life of the test. For example, to calculate the projected revenues for a main extension today, the MX test would assume that the rate for a customer who is connected today in 2015 would be the same rate the customer will pay each year for 20 years until 2035 (the MX test uses a modification of the discounting of future cash flows to accomplish this effect). This assumption produces test results that are not representative of reality as rates do not increase uniformly. As an example, all things equal, a drop in system-wide usage of gas will result in upward rate pressure that can be above and beyond inflationary rate pressures.

2.4.2.4 Modified MX Report

The MX Reports for 2008-2011 include a re-running of the MX Test using actuals and reforecasting unknown variables into the future. From 2012 forward, Commission staff requested a variation in the parameters in the MX test. The Companies therefore term this the "Modified MX Test" as this test no longer uses the same parameters as the original test.

[3] The FortisBC Energy Utilities 2012-2013 Revenue Requirements Application – Appendix E-3: Asset Loss Report p.9.

2.4.2.4.1 ATTACHMENTS AND RE-FORECASTING

The reporting requirements, as requested by Commission staff in the Modified MX Test, assume that if an attachment does not occur in its respective forecasted attachment year, then that attachment will never materialize. As such the Companies were requested to remove any attachments that did not occur in the year in which they were originally forecast, even though the Companies' experience shows that the vast majority of these attachments do occur over time. This methodology results in a re-forecasted forecast PI that is less representative of the true potential PI of a main extension, since many main extensions can face delays in construction thereby excluding the attachment because it did not occur in the specific year it was forecasted to occur.

2.4.2.4.2 MX TEST VERSUS MX REPORT CONSUMPTION CREDITS

The revenue portion of the original main extension test is calculated based on consumption credits using the average consumption of existing customers. The consumption credits are derived from the Residential End Use Study (REUS) which is updated approximately every four years with new average consumption values per appliance. In this manner, each new customer is treated equally compared to existing customers by ensuring that all customers receive equal credit when connecting to the system based on the appliances they are connecting. This is an important consideration in the development of the MX test and ensures that new customers are not penalized for having differing consumption patterns, such as more efficient homes and appliances, compared to existing customers who connected to the system when appliances and homes were less efficient. The Commission has approved this methodology and the Companies have been using this approach for over a decade.

Under the Modified MX Test, the re-forecast uses actual consumption. New residential customers use less gas for heating and hot water applications than do existing customers. Therefore, using actual consumption in the Modified MX Test instead of approved consumption (as derived from existing customers) will inherently produce a lower PI. This creates a misalignment when evaluating performance, as the Modified MX Test is using parameters that are different than that approved for the original test.

2.5 *RE-EVALUATING MX PERFORMANCE*

The following section provides a demonstration of the effect of changing some of the variables noted above and shows the impact this has on the historical profitability of the original MX Test. The results show that by simply manipulating or modifying parameters in the original MX Test and re-running the test, results in the profitability of the mains being volatile.

Table 2-1 is an excerpt from Letter L-34-14 that indicates the actual FEI and FEVI PI are 0.54 and 0.61 respectively using the MX Reporting methodology put forward by Commission staff.

Table 2-1: 2008 FEI and FEVI P.I. Tables from 2013 Main Extension Report

2008 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.60	0.54	-66%
Years 1-5 Total	**1.60**	**0.54**	**-66%**

2008 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.30	0.61	-53%
Years 1-5 Total	**1.30**	**0.61**	**-53%**

Table 2-2 demonstrates that the actual PI results from Table 1-2 increase considerably by simply altering/modifying a few key variables. The scenarios contained in the tables are based on the items discussed in Section 2.4 above. The scenarios in the table are also cumulative in that the assumptions from scenario 3 would also include the assumptions from scenario 1 and 2, and so on.

Table 2-2: 2008 FEI and FEVI Updated PI Scenarios

Scenario	Description of Table Methodology Versus Commission Methodology	FEI Change	FEVI Change	Re-Forecasted 2008 FEI P.I.	Re-Forecasted 2008 FEVI P.I.
1. MX Report Reporting Window	This re-forecasted P.I. includes all attachments up to the current reporting year regardless of the MX Report structure which only considers attachments in the first five years.	+50 attachments	+14 attachments	**.56**	**.62**
2. MX Test Asset Life	This re-forecasted P.I. considers all current attachments and associated revenue over the full life of the asset as opposed to the 20 year asset life used in the MX Test and MX Report.	40 Years	40 Years	**.85**	**.90**
3. MX Test Rates[4]	This re-forecasted P.I. includes actual 2014 rates and all current attachments and associated revenue over the full life of the asset. Whereas, the MX Test assumes rates are held constant.	2014 FEI Rates	2014 FEVI Rates	**1.00**	**1.11**
4. MX Report Re-Forecasting[5]	This re-forecasted P.I. considers all of the above as well as 10% growth in years 6 to 10 at average consumption for the sample. In contrast, the MX Test does not consider any growth on a main beyond the first five years of a main.	+45 attachments @ 52 GJ's	+27 attachments @ 29 GJ's	**1.03**	**1.18**
5. Consumption Credits[5]	Includes all of the above as well as uses the forecast average consumption values used in the initial MX Test at the time of connection. In comparison, the MX Report requires the re-forecasted MX Test include the actual consumption values for the main at the time of the Report.	Forecast Sample Consumption 96 GJ's	Forecast Sample Consumption 50 GJ's	**1.64**	**1.80**

[4] For these cases, the discount rate used in the re-forecasted main extension test has been adjusted for inflation since 2014 rates were used in place of the 2008 rates as part of the scenario. In other words, inflation was removed from the MX Test for those years where updated rates were used to reforecast the P.I.

The Companies believe that the MX Reporting methodology has significant limitations. As demonstrated above, re-forecasting an original forecast with different parameters gives different results. The extent to which these results vary suggests that the MX Test is not an appropriate evaluative tool as it does not result in reliable and valid results. In the MX Test Policy Review, directed to be filed later this year, the Companies will propose a reporting methodology they believe is a better tool to evaluate the success of a main extension.

3. MX WORKSHOPS AND POLICY REVIEW

The Companies have been proactively seeking to address the limitations in MX Reporting resulting from the limitations of the MX test as discussed in the previous section and, in addition, the Companies have led an initiative to examine the broader policy related system extension issues with their stakeholders.

3.1 *2012 EES REPORT AND RECOMMENDATIONS*

In 2012, the Companies retained EES Consulting[5] to perform research and benchmarking analysis for the Companies' Main Extension Policies against other utilities in Canada and the Pacific Northwest. EES Consulting was also requested to provide preliminary recommendations on alternative policy options.

A copy of the EES Report can be found in Appendix C of the 2012 Main Extension Report.

The Companies will be updating the 2012 EES Report in order to capture any changes or developments that have occurred at other utilities in the past few years with regards to their system extension policies. An updated version of the 2012 EES report will be submitted with the MX Test Policy Review application.

3.2 *2013-2014 STAKEHOLDER CONSULTATION*

Following the submission of the 2012 Main Extension Report and 2012 EES Report, the Companies met with individual stakeholders in late 2013 to seek their input on proceeding with a Main Extension Policy review. After meeting with individual stakeholders, the Companies conducted a series of four System Extension Stakeholder Workshops which took place throughout 2014. The workshops provided stakeholders with an opportunity to speak to the specific challenges faced by their constituents in attempting to access natural gas.

Throughout the workshop process, all relevant materials were provided to the stakeholders and to Commission staff, who attended the workshops under the role of a facilitator by supplying factual information, describing implications and advising participants of any precedents or regulatory issues pertaining to the discussions. A list of stakeholders the Companies met with throughout 2013 and 2014 is provided below.

- BC Ministry of Energy and Mines
- BC Ministry of Jobs, Tourism and Skills Training
- BC Public Interest Advocacy Centre

[5] EES Consulting – EES Consulting Ltd. is a multidisciplinary management consulting firm with particular expertise in Rate Design methodology and Cost of Service Allocation modelling, previously retained by the BCUC, FortisBC Inc., FEI (Terasen Gas Inc. at the time) for the validation of rate design methodologies and models.

- BC Sustainable Energy Association
- British Columbia Hydro and Power Authority
- Chawathil First Nation
- Commercial Energy Consumers of BC
- Fraser Valley Regional District
- MLA – Boundary-Similkameen
- MLA – Kootenay West
- Okanagan-Similkameen Regional District
- Pacific Northern Gas
- Peace River Regional District
- Seabird Island Band
- Sierra Club B.C.
- Yale First Nation

Table 3-1 below provides a summary of the pertinent issues discussed during the workshops.

Table 3-1: System Extension Stakeholder Workshop Summary

Date	Event Name	Framework	Topics Discussed
Q4 2013	Individual Consultation	Stakeholder Education & Support	• Policy Issues • Determine interest and support to initiate a policy review
February 18, 2014	Workshop #1	Policy Environment & Issues	• Different customer types and pricing impacts • Feedback from customers across BC • Comparison of other utilities by EES Consulting
June 18, 2014	Workshop #2	Stakeholder Input & Terms of Reference	• Regulatory precedent and changing market conditions • Determine scope and guiding principles for a review of connection policies for different customer types
October 8, 2014	Workshop #3	Solutions & Rate Impact Study	• Positive impacts of capital growth • Reporting and performance • Challenges faced by off-system communities
December 7, 2014	Workshop #4	Stakeholder Feedback and Application	• Incorporate Stakeholder feedback • Proposed changes to System Extension Policies through application to BCUC • Considerations in connecting Off-System Communities
Date	Event Name	Framework	• Topics Discussed

Date	Event Name	Framework	Topics Discussed
Q4 2013	Individual Consultation	Stakeholder Education & Support	• Policy Issues • Determine interest and support to initiate a policy review

In workshops 3 and 4, the Companies reviewed with stakeholders a preliminary analysis by EES Consulting showing the positive impacts on existing rate payers of capital growth. The conclusion by EES Consulting contrasted with the suggestion by the Commission in Letter L-34-14 that existing rate payers might be exposed to an undue cost burden. The Companies will be including the EES Consulting analysis in the MX Policy Review Application that will be filed later in the year as noted in Letter L-6-15.

4. MAIN EXTENSION TEST METHODOLOGY

Despite the belief of the Companies that using the MX Test to evaluate performance as part of the MX report is not valid or reliable, the Companies have fulfilled all the requests from the Commission and provide the report contained herein.

The MX test methodology is the same methodology used since 1998, and was most recently approved by the Commission in Order G-152-07. The Companies have provided in Appendix A and Appendix B the applicable Definitions and FEI General Terms & Conditions (GT&Cs), Section 12 Main Extension. The relevant terms found in these appendices apply throughout the 2013 MX Report.

4.1 *MX TEST FORMULA*

The tariff pages found in Appendix B set out the rules and process for customers wishing to attach to the Companies' natural gas distribution system. Where a main extension is required, an MX Test (as approved by the Commission) is applied. The test is the ratio of the net present value of revenues over the net present value of costs:

- If an individual PI is 0.8 or greater, the main extension can proceed without the need for a customer contribution.
- If an individual PI is less than 0.8, a customer contribution is required to bring the PI up to the 0.8 threshold, before the main extension can be built.
- An aggregate threshold PI of 1.1 is to be used for the portfolio of main extensions completed on an annual basis.

4.2 *MAIN EXTENSION DATA*

The 2014 MX Report contains main extension projects that have been organized using the following methodology:

- **2014 Mains** – Contain main extensions for the 2014 gas year (Nov-Oct) including forecasted attachments and consumption data and a comparison of the forecasted and actual main costs only. The first year of actual attachments and consumption data for this set of mains will be presented in the 2015 MX Report. This group of mains will be updated in each of the subsequent annual MX reports as required.
- **2013 Mains –** Contain main extensions for the 2013 gas year (Nov-Oct) and includes a comparison of forecasted and actual attachments, consumption and main costs from November 1, 2012 to October 31, 2013. The results in this Report reflect Year 1 of actualized data for this group of mains. 2018 will be the final year of reporting for this set of mains.

- **2012 Mains** – Contain main extensions for the 2012 gas year (Nov-Oct) and includes a comparison of forecasted and actual attachments, consumption and main costs from November 1, 2011 to October 31, 2013. The results in this Report reflect Year 2 of actualized data for this group of mains. 2017 will be the final year of reporting for this set of mains.
- **2011 Mains** – Contain main extensions for the 2011 gas year (Nov-Oct) and includes a comparison of forecasted and actual attachments, consumption and main costs from November 1, 2010 to October 31, 2013. The results in this report reflect Year 3 of actualized data for this group of mains. 2016 will be the final year of reporting for this set of mains.
- **2010 Mains** – Contain main extensions for the 2010 gas year (Nov-Oct) and includes a comparison of forecasted and actual attachments, consumption and main costs from November 1, 2009 to October 31, 2013. The results in this report reflect Year 4 of actualized data for this group of mains. 2015 will be the final year of reporting for this set of mains.
- **2009 Mains** – Contain main extensions for the 2009 gas year (Nov-Oct) and includes a comparison of forecasted and actual attachments, consumption and main costs from November 1, 2008 to October 31, 2012. The results in this report reflect Year 5 of actualized data for this group of mains.

The 2009-2014 main extension sample data sets were determined based on the following criteria:

1. All main segments in a particular data set must be installed after November 1st.
2. All main segments within a main extension project must be fully installed or "technically complete" (TECO'd) prior to October 31st.

The Companies are using a random sampling methodology for all data included in the 2014 MX Report, pursuant to Order G-152-07. The random samples were determined by calculating a statistical sample size which meets the criteria described in Order G-152-07 and then extracting that sample from the populations for each annual data set that met the conditions discussed above.

As a result, the 2014 FEI and FEVI populations consist of 198 and 93 completed mains respectively, with a random sample size of 50 and 39 respectively. The Companies note that the random sampling methodology is consistent with the previous reports, in which the data sets for the 2008-2013 gas are also based on the random sample method.

4.3 MAIN EXTENSION TEST PARAMETERS

The parameters used in the 2014 Main Extension Test are outlined below. For additional information on historical values, please see the 2012 Main Extension Report.

Net Cash Inflows

As discussed above, net revenue (cash inflows) are composed of the delivery margin plus connection fees, less O&M, a system improvement charge, property tax, and income tax. Each of these components is outlined in the following section.

The projected gross delivery margin for an entire main extension project used in the economic test is determined as follows:

a) estimating the number of customers to be served by the main extension[6];

b) establishing consumption estimates for each customer;

c) projecting when the customer will be connected to the main extension; and

d) applying the applicable delivery margin and rate for each customer.

The basic and delivery charges, the in lieu rate and new service fee data for 2014 are as follows:

6 Only those customers expected to connect to the main extension within 5 years of the completion are considered.

Table 4-1: Basic & Delivery Charges, In Lieu Rate & New Service Fee

		2014			
Rate Class	Rate Class	Basic Charge ($/yr)	Delivery Charge ($/GJ)	In Lieu Rate (%)	New Service Fee ($)
FEI	**FEI**				
Rate 1	Rate 1	$142.08	$3.62	1.84%	$25.00
Rate 2	Rate 2	$298.08	$2.94	2.15%	$25.00
Rate 3/23	Rate 3/23	$1,590.23	$2.47	1.92%	$25.00
Rate 4	Rate 4	$5,268.00	$1.78	3.03%	$25.00
Rate 5/25	Rate 5/25	$7,044.00	$17.85	1.27%	$25.00
Rate 6	Rate 6	$732.00	$3.99	1.81%	$25.00
Rate 7/27	Rate 7/27	$10,560.00	$1.20	1.04%	$25.00
FEVI	**FEVI**				
RGS	RGS	$126.00	$8.10	1.57%	$25.00
SCS-1	SCS-1	$113.40	$10.72	1.53%	$25.00
SCS-2	SCS-2	$402.36	$10.23	1.80%	$25.00
LCS-1	LCS-1	$732.00	$7.13	1.80%	$25.00
LSC-2	LSC-2	$1,173.84	$6.09	1.96%	$25.00
LCS-3	LCS-3	$2,418.12	$5.79	2.04%	$25.00
AGS	AGS	$480.00	$6.42	1.95%	$25.00

Additional inputs into the net cash inflows calculation are shown below:

Table 4-2: Net Cash Inflows Economic Parameters7

Economic Parameter FEI	2014	Economic Parameter FEVI	2014
O&M per Customer		**O&M per Customer**	
Residential	$79.00	***Residential***	$58.00
Commerical	$82.00	***Commerical***	$82.00
System Improvement (SI)	$0.24	**System Improvement (SI)**	$0.40
Property Tax Rate	1.91%	**Property Tax Rate**	1.88%
Income Tax Rate	26.00%	**Income Tax Rate**	26.00%

7 For this table, FEI Commercial is defined as Rate Schedule 2 and FEVI Commercial applies to all sales customers excluding Residential (RGS)

Notes:

- 2014 O&M per customer figures for FEI are from the 2014-2019 PBR Application.[8]
- 2014 O&M per customer figures for FEVI are from the 2014 FEVI RRA[9]
- Property tax rates are based on actual property tax payments. The income tax rates reflect the enacted income tax rates for 2014.

4.3.1 Consumption Credits

Consumption is calculated by determining the annual usage estimates by appliance type derived from operational experience and the Companies' Residential End Use Study (REUS) for existing customers. The consumption figures for 2014 are based on the 2008 REUS and the consumption figures for 2015 will be based on the 2014 REUS. The 2014 data is provided below.

Table 4-3: Appliance Use Credits for MX Test

Appliance	2011-2014 (GJ/yr) Lower Mainland	Interior	Vancouver Island
Barbeque	3.1	3.1	3.1
Boiler	62.0	51.6	43.0
Clothes Dryer	4.2	3.6	3.4
Fireplace - Décor	18.3	15.9	16.1
Fireplace - Heating	21.4	19.8	19.7
Furnace (primary)	62.0	51.6	43.0
Furnace (secondary)	18.1	39.3	19.9
Hot Tub	19.5	19.5	19.5
Hot Water Tank	20.4	18.8	18.8
Pool	38.5	38.5	38.5
Range/Cooktop	5.6	5.1	4.7
Wall Heater	7.1	7.1	7.1

Notes:

- Customers who install both high efficiency gas fired space and water heating receive a credit of 10 percent of the volume otherwise used for both appliances.
- Customers who install both high efficiency gas fired space and water heating appliances and attain a minimum of LEED™ (Leadership in Energy and Environmental Design) General Certification receive a credit of 15 percent of the volume otherwise used for both.
- Note that new customer consumption as reported may be significantly different than forecast consumption due to differences in end use customer usage.

8 The FortisBC Energy Inc. 2014-2018 PBR Application.
9 FEVI 2014 Revenue Requirements and Rates Application.

4.3.2 Attachments

The forecast of attachments of customers in the first five years of a main extension, is provided by sales based on discussions with the developer or the customer directly and is the *best estimate at that time*. As it is a forecast only, it is expected that there will be variances between forecast and actual.

4.3.2.1 Geographic (GEO) Codes and Manual Estimates

The Companies used either manual cost forecasting or postage stamp Geo based cost forecasting to determine main extension costs. This is explained in further detail in the 2012 Main Extension Report.

Additional economic parameters for 2014 are shown below:

Table 4-4: Geo Code & Manual Estimate Parameters

	Geo Code & Manual Pricing ($/metre)						
		PE Pipe ($/m)			Steel Pipe ($/m)		
	Zone	Up to 60 mm	88 - 114 mm	168 mm	Up to 60 mm	88 - 114 mm	168 mm
2014	Vancouver & Richmond	$56	Manual Estimates Only				
	North Shore & Squamish	$61					
	North of Fraser River	$53					
	South of Fraser River	$44					
	Interior North	$34					
	Interior South	$34					
	Vancouver Island	$50					

Table 4-5: Capital Cost Economic Parameters

Economic Parameters FEI	2014	Economic Parameters FEVI	2014
Overhead Rate	26.30%	Overhead Rate	26.30%
CCA Class 1	6.00%	CCA Class 1	6.00%
Discount Rate	4.50%	Discount Rate	4.40%
Working Capital Rate	0.50%	Working Capital Rate	0.50%

The following section outlines the methodologies associated with the three main components of a MX Test: consumption, attachments and costs. A more detailed discussion can be found in the 2012 Main Extension Report.

5. 2014 MAIN EXTENSIONS

The following section summarizes the aggregate and top 5 results for the 2014 main extensions including vertical subdivisions.

- The forecasted results contained in this section are based on projects for the 2014 gas year (November 01, 2013 to October 31, 2014).
- The first year of actual results for this section will appear in the 2015 Main Extension Report.
- The tables included in this section contain a comparison of forecasted and actual mains costs only.
- For the projects included in the Top 5 section, the Companies have provided explanations where unique circumstances exist. For those projects that do not include explanations, variances are a result of labour or material cost differences or the challenges in accurately forecasting attachments and consumption.
- The grey shading in the tables below is used to indicate a forecast year.

5.1 *2014 FEI SAMPLE RESULTS*

The tables below summarize the sample aggregate 2014 main extension results for FEI.

1 **Table 5-1: 2014 FEI Aggregate Main Extensions Costs**

2014 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 465,830	$ 414,725	-11%
	Service lines and meters	$ 292,415	$ -	-100%
	Year 1 Total	$ 758,245	$ 414,725	-45%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 66,381	$ -	-100%
	Year 2 Total	$ 66,381	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 47,896	$ -	-100%
	Year 3 Total	$ 47,896	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 35,291	$ -	-100%
	Year 4 Total	$ 35,291	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 26,889	$ -	-100%
	Year 5 Total	$ 26,889	$ -	-100%
Years 1-5 Total		**$934,702**	**$414,725**	**-56%**

2

Table 5-2: 2014 FEI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2014 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
FEI	Attachments			Consumption (GJ)			Use per Customer		
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	**348**	**348**	**0%**	**73,161**	**73,161**	**0%**	**210**	**210**	**0%**
Rate 1	*298*	*298*	*0%*	*13,295*	*13,295*	*0%*	*45*	*45*	*0%*
Rate 2	*47*	*47*	*0%*	*15,756*	*15,756*	*0%*	*335*	*335*	*0%*
Rate 3	*3*	*3*	*0%*	*44,110*	*44,110*	*0%*	*14,703*	*14,703*	*0%*
Year 2	**427**	**427**	**0%**	**78,399**	**78,399**	**0%**	**184**	**184**	**0%**
Rate 1	*376*	*376*	*0%*	*18,298*	*18,298*	*0%*	*49*	*49*	*0%*
Rate 2	*48*	*48*	*0%*	*15,991*	*15,991*	*0%*	*333*	*333*	*0%*
Rate 3	*3*	*3*	*0%*	*44,110*	*44,110*	*0%*	*14,703*	*14,703*	*0%*
Year 3	**484**	**484**	**0%**	**82,307**	**82,307**	**0%**	**170**	**170**	**0%**
Rate 1	*433*	*433*	*0%*	*22,206*	*22,206*	*0%*	*51*	*51*	*0%*
Rate 2	*48*	*48*	*0%*	*15,991*	*15,991*	*0%*	*333*	*333*	*0%*
Rate 3	*3*	*3*	*0%*	*44,110*	*44,110*	*0%*	*14,703*	*14,703*	*0%*
Year 4	**526**	**526**	**0%**	**85,630**	**85,630**	**0%**	**163**	**163**	**0%**
Rate 1	*475*	*475*	*0%*	*25,529*	*25,529*	*0%*	*54*	*54*	*0%*
Rate 2	*48*	*48*	*0%*	*15,991*	*15,991*	*0%*	*333*	*333*	*0%*
Rate 3	*3*	*3*	*0%*	*44,110*	*44,110*	*0%*	*14,703*	*14,703*	*0%*
Year 5	**558**	**558**	**0%**	**88,071**	**88,071**	**0%**	**158**	**158**	**0%**
Rate 1	*507*	*507*	*0%*	*27,970*	*27,970*	*0%*	*55*	*55*	*0%*
Rate 2	*48*	*48*	*0%*	*15,991*	*15,991*	*0%*	*333*	*333*	*0%*
Rate 3	*3*	*3*	*0%*	*44,110*	*44,110*	*0%*	*14,703*	*14,703*	*0%*
Years 1-5 Total	**558**	**558**	**0%**	**407,568**	**407,568**	**0%**	**158**	**158**	**0%**

Table 5-3: 2014 FEI Aggregate Main Extensions Profitability Index

2014 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	2.04	2.05	0%
Years 1-5 Total	**2.04**	**2.05**	**0%**

Notes:

- The actual main extension costs compared to forecast costs are $50,000 lower for FEI representing an 11 percent cost variance. This variance is reasonable in that it is as accurate as possible without adding substantively to the administrative workload associated with estimating main extension costs.
- 8 FEI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

5.2 2014 FEVI SAMPLE RESULTS

The tables below summarize the sample aggregate 2014 main extension results for FEVI.

Table 5-4: 2014 FEVI Aggregate Main Extensions Costs

2014 SAMPLE MAIN EXTENSIONS - COSTS				
FEVI	Cost of Installation ($)			
		Original Forecast	Actual	Variance %
Year 1	Mains	$ 1,356,549	$ 909,936	-33%
	Service lines and meters	$ 197,031	$ -	-100%
	Year 1 Total	$ 1,553,580	$ 909,936	-41%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 67,241	$ -	-100%
	Year 2 Total	$ 67,241	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 67,241	$ -	-100%
	Year 3 Total	$ 67,241	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 48,476	$ -	-100%
	Year 4 Total	$ 48,476	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$1,736,537**	**$909,936**	**-48%**

Table 5-5: 2014 FEVI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2014 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
FEVI	Attachments			Consumption (GJ)			Use per Customer		
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	**126**	**126**	**0%**	**43,446**	**43,446**	**0%**	**345**	**345**	**0%**
Rate 1	*117*	*117*	*0%*	*5,477*	*5,477*	*0%*	*47*	*47*	*0%*
Rate 2	*7*	*7*	*0%*	*3,516*	*3,516*	*0%*	*502*	*502*	*0%*
Rate 3	*2*	*2*	*0%*	*34,453*	*34,453*	*0%*	*17,227*	*17,227*	*0%*
Year 2	**169**	**169**	**0%**	**45,729**	**45,729**	**0%**	**271**	**271**	**0%**
Rate 1	*159*	*159*	*0%*	*7,700*	*7,700*	*0%*	*48*	*48*	*0%*
Rate 2	*8*	*8*	*0%*	*3,576*	*3,576*	*0%*	*447*	*447*	*0%*
Rate 3	*2*	*2*	*0%*	*34,453*	*34,453*	*0%*	*17,227*	*17,227*	*0%*
Year 3	**212**	**212**	**0%**	**48,209**	**48,209**	**0%**	**227**	**227**	**0%**
Rate 1	*202*	*202*	*0%*	*10,180*	*10,180*	*0%*	*50*	*50*	*0%*
Rate 2	*8*	*8*	*0%*	*3,576*	*3,576*	*0%*	*447*	*447*	*0%*
Rate 3	*2*	*2*	*0%*	*34,453*	*34,453*	*0%*	*17,227*	*17,227*	*0%*
Year 4	**243**	**243**	**0%**	**50,237**	**50,237**	**0%**	**207**	**207**	**0%**
Rate 1	*233*	*233*	*0%*	*12,208*	*12,208*	*0%*	*52*	*52*	*0%*
Rate 2	*8*	*8*	*0%*	*3,576*	*3,576*	*0%*	*447*	*447*	*0%*
Rate 3	*2*	*2*	*0%*	*34,453*	*34,453*	*0%*	*17,227*	*17,227*	*0%*
Year 5	**243**	**243**	**0%**	**50,237**	**50,237**	**0%**	**207**	**207**	**0%**
Rate 1	*233*	*233*	*0%*	*12,208*	*12,208*	*0%*	*52*	*52*	*0%*
Rate 2	*8*	*8*	*0%*	*3,576*	*3,576*	*0%*	*447*	*447*	*0%*
Rate 3	*2*	*2*	*0%*	*34,453*	*34,453*	*0%*	*17,227*	*17,227*	*0%*
Years 1-5 Total	**243**	**243**	**0%**	**237,858**	**237,858**	**0%**	**207**	**207**	**0%**

Table 5-6: 2014 FEVI Aggregate Main Extensions Profitability Index

2014 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.59	2.13	34%
Years 1-5 Total	**1.59**	**2.13**	**34%**

Notes:

- The actual main extension costs compared to forecast costs are $450,000 lower for FEVI representing a 34 percent cost variance. There are several main extensions in the sample where costs have not been finalized as they were completed near year end.
- 7 FEVI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

5.3 2014 FEI TOP 5 RESULTS

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 5-7 & 5-8	Table 5-9 & 5-10	Table 5-11 & 5-12	Table 5-13 & 5-14	Table 5-15 & 5-16	Table 5-17
Maclure Road	244 Avenue	Predator Ridge Drive	Highland Drive	Plateau Drive	Top 5 P.I. Results

Table 5-7: 2014 FEI Top 5 – Maclure Road Costs

2014 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550003872	Maclure Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 15,120	$ 51,771	242%
	Service lines and meters	$ 9,243	$ -	-100%
	Year 1 Total	$ 24,363	$ 51,771	112%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 8,403	$ -	-100%
	Year 2 Total	$ 8,403	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 5,882	$ -	-100%
	Year 3 Total	$ 5,882	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$38,648**	**$51,771**	**34%**

Table 5-8: 2014 FEI Top 5 – Maclure Road Attachments, Consumption and Use per Customer

2014 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550003872 Maclure Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	80%
Year 1	**11**	**11**	**0%**	**1,377**	**1,377**	**0%**	**125**	**125**	**0%**	
Rate 1	*11*	*11*	*0%*	*1,377*	*1,377*	*0%*	*125*	*125*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**21**	**21**	**0%**	**2,629**	**2,629**	**0%**	**125**	**125**	**0%**	
Rate 1	*21*	*21*	*0%*	*2,629*	*2,629*	*0%*	*125*	*125*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**28**	**28**	**0%**	**3,505**	**3,505**	**0%**	**125**	**125**	**0%**	
Rate 1	*28*	*28*	*0%*	*3,505*	*3,505*	*0%*	*125*	*125*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**28**	**28**	**0%**	**3,505**	**3,505**	**0%**	**125**	**125**	**0%**	
Rate 1	*28*	*28*	*0%*	*3,505*	*3,505*	*0%*	*125*	*125*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**28**	**28**	**0%**	**3,505**	**3,505**	**0%**	**125**	**125**	**0%**	
Rate 1	*28*	*28*	*0%*	*3,505*	*3,505*	*0%*	*125*	*125*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**28**	**28**	**0%**	**14,521**	**14,521**	**0%**	**125**	**125**	**0%**	

Notes:

- Additional costs were incurred for 2 unanticipated road crossings due to a re-design of the subdivision.
- Further costs were incurred as a result of a planner decision to run additional main down both sides of the street to reduce future remediation costs when the services are installed. This decision was made after the project had already begun construction.

Table 5-9: 2014 FEI Top 5 – 244 Avenue Costs

2014 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550006721	244 Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 39,859	$ 59,726	50%
	Service lines and meters	$ 17,646	$ -	-100%
	Year 1 Total	$ 57,505	$ 59,726	4%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 6,722	$ -	-100%
	Year 2 Total	$ 6,722	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$64,227**	**$59,726**	**-7%**

Table 5-10: 2014 FEI Top 5 – 244 Avenue Attachments, Consumption and Use per Customer

2014 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550006721 244 Avenue	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	80%
Year 1	**21**	**21**	**0%**	**2,180**	**2,180**	**0%**	**104**	**104**	**0%**	
Rate 1	*21*	*21*	*0%*	*2,180*	*2,180*	*0%*	*104*	*104*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**29**	**29**	**0%**	**3,010**	**3,010**	**0%**	**104**	**104**	**0%**	
Rate 1	*29*	*29*	*0%*	*3,010*	*3,010*	*0%*	*104*	*104*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**29**	**29**	**0%**	**3,010**	**3,010**	**0%**	**104**	**104**	**0%**	
Rate 1	*29*	*29*	*0%*	*3,010*	*3,010*	*0%*	*104*	*104*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**29**	**29**	**0%**	**3,010**	**3,010**	**0%**	**104**	**104**	**0%**	
Rate 1	*29*	*29*	*0%*	*3,010*	*3,010*	*0%*	*104*	*104*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**29**	**29**	**0%**	**3,010**	**3,010**	**0%**	**104**	**104**	**0%**	
Rate 1	*29*	*29*	*0%*	*3,010*	*3,010*	*0%*	*104*	*104*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**29**	**29**	**0%**	**14,220**	**14,220**	**0%**	**104**	**104**	**0%**	

Notes:

- Additional costs related to the purchase and delivery of aggregate were incurred for this project as a result of re-grading to ensure the main was installed at a safe depth.

1 **Table 5-11: 2014 FEI Top 5 – Predator Ridge Drive Costs**

2014 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550007707	Predator Ridge Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 96,710	$ 109,470	13%
	Service lines and meters	$ 5,042	$ -	-100%
	Year 1 Total	$ 101,752	$ 109,470	8%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 8,403	$ -	-100%
	Year 2 Total	$ 8,403	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 5,042	$ -	-100%
	Year 3 Total	$ 5,042	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 5,042	$ -	-100%
	Year 4 Total	$ 5,042	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 5,042	$ -	-100%
	Year 5 Total	$ 5,042	$ -	-100%
Years 1-5 Total		**$125,279**	**$109,470**	**-13%**

2

Table 5-12: 2014 FEI Top 5 – Predator Ridge Drive Attachments, Consumption and Use per Customer

2014 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550007707 redator Ridge Driv	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	80%
Year 1	**6**	**6**	**0%**	**652**	**652**	**0%**	**109**	**109**	**0%**	
Rate 1	*6*	*6*	*0%*	*652*	*652*	*0%*	*109*	*109*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**16**	**16**	**0%**	**1,726**	**1,726**	**0%**	**108**	**108**	**0%**	
Rate 1	*16*	*16*	*0%*	*1,726*	*1,726*	*0%*	*108*	*108*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**22**	**22**	**0%**	**2,378**	**2,378**	**0%**	**108**	**108**	**0%**	
Rate 1	*22*	*22*	*0%*	*2,378*	*2,378*	*0%*	*108*	*108*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**28**	**28**	**0%**	**3,030**	**3,030**	**0%**	**108**	**108**	**0%**	
Rate 1	*28*	*28*	*0%*	*3,030*	*3,030*	*0%*	*108*	*108*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**34**	**34**	**0%**	**3,682**	**3,682**	**0%**	**108**	**108**	**0%**	
Rate 1	*34*	*34*	*0%*	*3,682*	*3,682*	*0%*	*108*	*108*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**34**	**34**	**0%**	**11,468**	**11,468**	**0%**	**108**	**108**	**0%**	

Table 5-13: 2014 FEI Top 5 – Highland Drive Costs

2014 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550008051	Highland Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 22,000	$ 98,934	350%
	Service lines and meters	$ 12,604	$ -	-100%
	Year 1 Total	$ 34,604	$ 98,934	186%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 12,604	$ -	-100%
	Year 2 Total	$ 12,604	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 11,764	$ -	-100%
	Year 3 Total	$ 11,764	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 12,604	$ -	-100%
	Year 4 Total	$ 12,604	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 14,285	$ -	-100%
	Year 5 Total	$ 14,285	$ -	-100%
Years 1-5 Total		**$85,861**	**$98,934**	**15%**

Table 5-14: 2014 FEI Top 5 – Highland Drive Attachments, Consumption and Use per Customer

2014 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550008051 Highland Drive	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	80%
Year 1	**15**	**15**	**0%**	**1,409**	**1,409**	**0%**	**94**	**94**	**0%**	
Rate 1	*15*	*15*	*0%*	*1,409*	*1,409*	*0%*	*94*	*94*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**30**	**30**	**0%**	**2,818**	**2,818**	**0%**	**94**	**94**	**0%**	
Rate 1	*30*	*30*	*0%*	*2,818*	*2,818*	*0%*	*94*	*94*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**44**	**44**	**0%**	**4,126**	**4,126**	**0%**	**94**	**94**	**0%**	
Rate 1	*44*	*44*	*0%*	*4,126*	*4,126*	*0%*	*94*	*94*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**59**	**59**	**0%**	**5,535**	**5,535**	**0%**	**94**	**94**	**0%**	
Rate 1	*59*	*59*	*0%*	*5,535*	*5,535*	*0%*	*94*	*94*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**76**	**76**	**0%**	**7,145**	**7,145**	**0%**	**94**	**94**	**0%**	
Rate 1	*76*	*76*	*0%*	*7,145*	*7,145*	*0%*	*94*	*94*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**76**	**76**	**0%**	**21,033**	**21,033**	**0%**	**94**	**94**	**0%**	

Notes:

- There were planning and time delays for this project due to steep terrain associated with this project.

1 **Table 5-15: 2014 FEI Top 5 – Plateau Drive Costs**

2014 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550008847	Plateau Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 60,754	$ 80,741	33%
	Service lines and meters	$ 7,562	$ -	-100%
	Year 1 Total	$ 68,317	$ 80,741	18%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 8,403	$ -	-100%
	Year 2 Total	$ 8,403	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 8,403	$ -	-100%
	Year 3 Total	$ 8,403	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 8,403	$ -	-100%
	Year 4 Total	$ 8,403	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 4,201	$ -	-100%
	Year 5 Total	$ 4,201	$ -	-100%
Years 1-5 Total		**$97,726**	**$80,741**	**-17%**

2

Table 5-16: 2014 FEI Top 5 – Plateau Drive Attachments, Consumption and Use per Customer

2014 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI 5550008847 Plateau Drive	Attachments			Consumption (GJ)			Use per Customer			
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	80%
Year 1	**9**	**9**	**0%**	**818**	**818**	**0%**	**91**	**91**	**0%**	
Rate 1	*9*	*9*	*0%*	*818*	*818*	*0%*	*91*	*91*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**19**	**19**	**0%**	**1,735**	**1,735**	**0%**	**91**	**91**	**0%**	
Rate 1	*19*	*19*	*0%*	*1,735*	*1,735*	*0%*	*91*	*91*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**29**	**29**	**0%**	**2,652**	**2,652**	**0%**	**91**	**91**	**0%**	
Rate 1	*29*	*29*	*0%*	*2,652*	*2,652*	*0%*	*91*	*91*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**39**	**39**	**0%**	**3,561**	**3,561**	**0%**	**91**	**91**	**0%**	
Rate 1	*39*	*39*	*0%*	*3,561*	*3,561*	*0%*	*91*	*91*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**44**	**44**	**0%**	**4,015**	**4,015**	**0%**	**91**	**91**	**0%**	
Rate 1	*44*	*44*	*0%*	*4,015*	*4,015*	*0%*	*91*	*91*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**44**	**44**	**0%**	**12,781**	**12,781**	**0%**	**91**	**91**	**0%**	

Notes:

- An issue with a retaining wall and rock removal added to the additional costs. There were also conflicts with an existing BC Hydro line being too close in proximity to the gas line.

Table 5-17: 2014 FEI Top 5 Main Extensions Profitability Index

2013 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Maclure Road	1.98	1.11	-44%
244 Avenue	1.00	0.81	-19%
Predator Ridge	0.80	0.71	-12%
Highland Drive	1.07	0.91	-14%
Plateau Drive	0.84	0.71	-16%
Years 1-5 Total	**1.14**	**0.85**	**-25%**

5.4 *2014 FEVI TOP 5 RESULTS*

The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 5-18 & 5-19	Table 5-20 & 5-21	Table 5-22 & 5-23	Table 5-24 & 5-25	Table 5-26 & 5-27	Table 5-28
Stamp Way	Westwood Road	East Saanich Road	Road A	Howard Avenue	Top 5 P.I. Results

Table 5-18: 2014 FEVI Top 5 – Stamp Way Costs

2014 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550007879	Stamp Way	Original Forecast	Actual	Variance %
Year 1	Mains	$ 12,500	$ 48,079	285%
	Service lines and meters	$ 4,691	$ -	-100%
	Year 1 Total	$ 17,191	$ 48,079	180%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 3,127	$ -	-100%
	Year 3 Total	$ 3,127	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$20,319**	**$48,079**	**137%**

Table 5-19: 2014 FEVI Top 5 – Stamp Way Attachments, Consumption and Use per Customer

2014 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550007879 Stamp Way	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	80%
Year 1	**3**	**3**	**0%**	**182**	**182**	**0%**	**61**	**61**	**0%**	
Rate 1	*3*	*3*	*0%*	*182*	*182*	*0%*	*61*	*61*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**3**	**3**	**0%**	**182**	**182**	**0%**	**61**	**61**	**0%**	
Rate 1	*3*	*3*	*0%*	*182*	*182*	*0%*	*61*	*61*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**5**	**5**	**0%**	**278**	**278**	**0%**	**56**	**56**	**0%**	
Rate 1	*5*	*5*	*0%*	*278*	*278*	*0%*	*56*	*56*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**5**	**5**	**0%**	**278**	**278**	**0%**	**56**	**56**	**0%**	
Rate 1	*5*	*5*	*0%*	*278*	*278*	*0%*	*56*	*56*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**5**	**5**	**0%**	**278**	**278**	**0%**	**56**	**56**	**0%**	
Rate 1	*5*	*5*	*0%*	*278*	*278*	*0%*	*56*	*56*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**5**	**5**	**0%**	**1,198**	**1,198**	**0%**	**56**	**56**	**0%**	

Notes:

- A large amount of rock was encountered during construction resulting in removal, dumping and aggregate fees associate with restoration.

1 **Table 5-20: 2014 FEVI Top 5 – Westwood Road Costs**

2014 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550008861	Westwood Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 35,715	$ 56,927	59%
	Service lines and meters	$ 7,819	$ -	-100%
	Year 1 Total	$ 43,533	$ 56,927	31%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 9,382	$ -	-100%
	Year 2 Total	$ 9,382	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 18,765	$ -	-100%
	Year 3 Total	$ 18,765	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 4,691	$ -	-100%
	Year 4 Total	$ 4,691	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$76,372**	**$56,927**	**-25%**

2

Table 5-21: 2014 FEVI Top 5 – Westwood Road Attachments, Consumption and Use per Customer

2014 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550008861 Westwood Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	80%
Year 1	**5**	**5**	**0%**	**193**	**193**	**0%**	**39**	**39**	**0%**	
Rate 1	*5*	*5*	*0%*	*193*	*193*	*0%*	*39*	*39*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**11**	**11**	**0%**	**402**	**402**	**0%**	**37**	**37**	**0%**	
Rate 1	*11*	*11*	*0%*	*402*	*402*	*0%*	*37*	*37*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**23**	**23**	**0%**	**821**	**821**	**0%**	**36**	**36**	**0%**	
Rate 1	*23*	*23*	*0%*	*821*	*821*	*0%*	*36*	*36*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**26**	**26**	**0%**	**926**	**926**	**0%**	**36**	**36**	**0%**	
Rate 1	*26*	*26*	*0%*	*926*	*926*	*0%*	*36*	*36*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**26**	**26**	**0%**	**926**	**926**	**0%**	**36**	**36**	**0%**	
Rate 1	*26*	*26*	*0%*	*926*	*926*	*0%*	*36*	*36*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**26**	**26**	**0%**	**3,268**	**3,268**	**0%**	**36**	**36**	**0%**	

Notes:

- Due to an expectation to encounter a significant amount of rock, this project was manually estimated. However, costs came in greater than forecast due to the prevalence of difficult installations conditions.

1 **Table 5-22: 2014 FEVI Top 5 – East Saanich Road Costs**

2014 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550008872	East Saanich Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 21,420	$ 75,692	253%
	Service lines and meters	$ 62,549	$ -	-100%
	Year 1 Total	$ 83,969	$ 75,692	-10%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$83,969**	**$75,692**	**-10%**

2

Table 5-23: 2014 FEVI Top 5 – East Saanich Road Attachments, Consumption and Use per Customer

2014 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550008872 East Saanich Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	80%
Year 1	**40**	**40**	**0%**	**912**	**912**	**0%**	**23**	**23**	**0%**	
Rate 1	*40*	*40*	*0%*	*912*	*912*	*0%*	*23*	*23*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**40**	**40**	**0%**	**912**	**912**	**0%**	**23**	**23**	**0%**	
Rate 1	*40*	*40*	*0%*	*912*	*912*	*0%*	*23*	*23*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**40**	**40**	**0%**	**912**	**912**	**0%**	**23**	**23**	**0%**	
Rate 1	*40*	*40*	*0%*	*912*	*912*	*0%*	*23*	*23*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**40**	**40**	**0%**	**912**	**912**	**0%**	**23**	**23**	**0%**	
Rate 1	*40*	*40*	*0%*	*912*	*912*	*0%*	*23*	*23*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**40**	**40**	**0%**	**912**	**912**	**0%**	**23**	**23**	**0%**	
Rate 1	*40*	*40*	*0%*	*912*	*912*	*0%*	*23*	*23*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**40**	**40**	**0%**	**4,560**	**4,560**	**0%**	**23**	**23**	**0%**	

Notes:

- The $76,000 main installation costs for this project also include the costs of the service lines.
- The main installation was approximately $39,000 and due in additional paving and compaction costs.

1 **Table 5-24: 2014 FEVI Top 5 – Road A Costs**

2014 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550009123	Road A	Original Forecast	Actual	Variance %
Year 1	Mains	$ 27,793	$ 23,735	-15%
	Service lines and meters	$ 15,637	$ -	-100%
	Year 1 Total	$ 43,430	$ 23,735	-45%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 12,510	$ -	-100%
	Year 2 Total	$ 12,510	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 12,510	$ -	-100%
	Year 3 Total	$ 12,510	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$68,450**	**$23,735**	**-65%**

2

1 **Table 5-25: 2014 FEVI Top 5 – Road A Attachments, Consumption and Use per Customer**

2014 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550009123 Road A	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	80%
Year 1	**10**	**10**	**0%**	**275**	**275**	**0%**	**28**	**28**	**0%**	
Rate 1	*10*	*10*	*0%*	*275*	*275*	*0%*	*28*	*28*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**18**	**18**	**0%**	**495**	**495**	**0%**	**28**	**28**	**0%**	
Rate 1	*18*	*18*	*0%*	*495*	*495*	*0%*	*28*	*28*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**26**	**26**	**0%**	**715**	**715**	**0%**	**28**	**28**	**0%**	
Rate 1	*26*	*26*	*0%*	*715*	*715*	*0%*	*28*	*28*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**26**	**26**	**0%**	**715**	**715**	**0%**	**28**	**28**	**0%**	
Rate 1	*26*	*26*	*0%*	*715*	*715*	*0%*	*28*	*28*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**26**	**26**	**0%**	**715**	**715**	**0%**	**28**	**28**	**0%**	
Rate 1	*26*	*26*	*0%*	*715*	*715*	*0%*	*28*	*28*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**26**	**26**	**0%**	**2,915**	**2,915**	**0%**	**28**	**28**	**0%**	

2

Table 5-26: 2014 FEVI Top 5 – Howard Avenue Costs

2014 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550009619	Howard Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 13,100	$ 22,676	73%
	Service lines and meters	$ 6,255	$ -	-100%
	Year 1 Total	$ 19,355	$ 22,676	17%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 6,255	$ -	-100%
	Year 2 Total	$ 6,255	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 6,255	$ -	-100%
	Year 3 Total	$ 6,255	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$31,865**	**$22,676**	**-29%**

Table 5-27: 2014 FEVI Top 5 – Howard Avenue Attachments, Consumption and Use per Customer

2014 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550009619 Howard Avenue	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	80%
Year 1	**4**	**4**	**0%**	**254**	**254**	**0%**	**64**	**64**	**0%**	
Rate 1	*4*	*4*	*0%*	*254*	*254*	*0%*	*64*	*64*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**8**	**8**	**0%**	**508**	**508**	**0%**	**64**	**64**	**0%**	
Rate 1	*8*	*8*	*0%*	*508*	*508*	*0%*	*64*	*64*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**12**	**12**	**0%**	**762**	**762**	**0%**	**64**	**64**	**0%**	
Rate 1	*12*	*12*	*0%*	*762*	*762*	*0%*	*64*	*64*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**12**	**12**	**0%**	**762**	**762**	**0%**	**64**	**64**	**0%**	
Rate 1	*12*	*12*	*0%*	*762*	*762*	*0%*	*64*	*64*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**12**	**12**	**0%**	**762**	**762**	**0%**	**64**	**64**	**0%**	
Rate 1	*12*	*12*	*0%*	*762*	*762*	*0%*	*64*	*64*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**12**	**12**	**0%**	**3,048**	**3,048**	**0%**	**64**	**64**	**0%**	

Notes:

- Services were planned to be installed by machine boring under freshly poured concrete curbs, however due to a revised construction design of the curbs a significant amount of hand digging was required resulting in higher labour costs for this project.

Table 5-29: 2014 FEVI Top 5 Main Extensions Profitability Index

2013 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Stamp Way	0.80	0.22	-72%
Westwood Road	0.91	0.67	-27%
East Saanich Road	0.88	0.49	-44%
Road A	0.87	0.94	8%
Howard Avenue	1.59	1.20	-25%
Years 1-5 Total	**1.01**	**0.70**	**-31%**

6. 2013 MAIN EXTENSIONS

The following section summarizes the aggregate and top 5 results for the 2013 main extensions including vertical subdivisions.

- The forecasted results contained in this section are based on projects for the 2013 gas year (November 01, 2012 to October 31, 2013).
- The first year of actual results for this section will appear in the 2014 Main Extension Report.
- The tables included in this section contain a comparison of forecasted and actual mains costs only.
- For the projects included in the Top 5 section, the Companies have provided explanations where unique circumstances exist. For those projects that do not include explanations, variances are a result of labour or material cost differences or the challenges in accurately forecasting attachments and consumption.
- The grey shading in the tables below is used to indicate a forecast year.

The 2013 main extension data tables as well as future report tables reflect the expanded rate class breakdown as discussed in Section 1.

6.1 *2013 FEI SAMPLE RESULTS*

The tables below summarize the sample aggregate 2013 main extension results for FEI.

Table 6-1: 2013 FEI Aggregate Main Extensions Costs

2013 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 2,322	$ 3,502	51%
	Service lines and meters	$ 297,092	$ 546,463	84%
	Year 1 Total	$ 299,414	$ 549,965	84%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 135,042	$ -	-100%
	Year 2 Total	$ 135,042	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 89,619	$ -	-100%
	Year 3 Total	$ 89,619	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 62,610	$ -	-100%
	Year 4 Total	$ 62,610	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 49,106	$ -	-100%
	Year 5 Total	$ 49,106	$ -	-100%
Years 1-5 Total		**$635,791**	**$549,965**	**-13%**

Table 6-2: 2013 FEI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2013 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
FEI	Attachments			Consumption (GJ)			Use per Customer		
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	**242**	**367**	**52%**	**49,923**	**51,338**	**3%**	**206**	**140**	**-32%**
Rate 1	*194*	*317*	*63%*	*18,383*	*13,672*	*-26%*	*95*	*43*	*-54%*
Rate 2	*48*	*45*	*-6%*	*31,540*	*18,807*	*-40%*	*657*	*418*	*-36%*
Rate 3	*0*	*5*		*0*	*18,859*			*3,772*	
Year 2	**352**	**477**	**36%**	**62,716**	**64,131**	**2%**	**178**	**134**	**-25%**
Rate 1	*299*	*422*	*41%*	*28,020*	*23,309*	*-17%*	*94*	*55*	*-41%*
Rate 2	*53*	*50*	*-6%*	*34,696*	*21,963*	*-37%*	*655*	*439*	*-33%*
Rate 3	*0*	*5*		*0*	*18,859*			*3,772*	
Year 3	**425**	**550**	**29%**	**69,192**	**70,607**	**2%**	**163**	**128**	**-21%**
Rate 1	*372*	*495*	*33%*	*34,496*	*29,785*	*-14%*	*93*	*60*	*-35%*
Rate 2	*53*	*50*	*-6%*	*34,696*	*21,963*	*-37%*	*655*	*439*	*-33%*
Rate 3	*0*	*5*		*0*	*18,859*			*3,772*	
Year 4	**476**	**601**	**26%**	**73,782**	**75,197**	**2%**	**155**	**125**	**-19%**
Rate 1	*423*	*546*	*29%*	*39,086*	*34,375*	*-12%*	*92*	*63*	*-32%*
Rate 2	*53*	*50*	*-6%*	*34,696*	*21,963*	*-37%*	*655*	*439*	*-33%*
Rate 3	*0*	*5*		*0*	*18,859*			*3,772*	
Year 5	**516**	**641**	**24%**	**77,509**	**78,924**	**2%**	**150**	**123**	**-18%**
Rate 1	*463*	*586*	*27%*	*42,813*	*38,102*	*-11%*	*92*	*65*	*-30%*
Rate 2	*53*	*50*	*-6%*	*34,696*	*21,963*	*-37%*	*655*	*439*	*-33%*
Rate 3	*0*	*5*		*0*	*18,859*			*3,772*	
Years 1-5 Total	**516**	**641**	**24%**	**333,122**	**340,199**	**2%**	**150**	**123**	**-18%**

Table 6-3: 2013 FEI Aggregate Main Extensions Profitability Index

2013 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.78	1.59	-11%
Years 1-5 Total	**1.78**	**1.59**	**-11%**

Notes:

- The actual main extension costs compared to forecast costs are $76,000 higher for FEI representing a 15 percent cost variance. This variance is reasonable in that it is as accurate as possible without adding substantively to the administrative workload associated with estimating main extension costs.

- 6 FEI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

6.2 *2013 FEVI SAMPLE RESULTS*

The tables below summarize the sample aggregate 2013 main extension results for FEVI.

Table 6-4: 2013 FEVI Aggregate Main Extensions Costs

2013 SAMPLE MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
		Original Forecast	Actual	Variance %
Year 1	Mains	$ 366,502	$ 352,995	-4%
	Service lines and meters	$ 152,687	$ 217,465	42%
	Year 1 Total	$ 519,189	$ 570,460	10%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 76,877	$ -	-100%
	Year 2 Total	$ 76,877	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 18,152	$ -	-100%
	Year 3 Total	$ 18,152	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$614,218**	**$570,460**	**-7%**

Table 6-5: 2013 FEVI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2013 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
	Attachments			Consumption (GJ)			Use per Customer		
FEVI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	**143**	**155**	**8%**	**9,262**	**4,764**	**-49%**	**65**	**31**	**-53%**
Rate 1	*131*	*152*	*16%*	*6,406*	*4,015*	*-37%*	*49*	*26*	*-46%*
Rate 2	*10*	*1*	*-90%*	*1,256*	*229*	*-82%*	*126*	*229*	*83%*
Rate 3	*2*	*2*	*0%*	*1,600*	*520*	*-67%*	*800*	*260*	*-67%*
Year 2	**215**	**227**	**6%**	**12,385**	**7,887**	**-36%**	**58**	**35**	**-40%**
Rate 1	*203*	*224*	*10%*	*9,529*	*7,138*	*-25%*	*47*	*32*	*-32%*
Rate 2	*10*	*1*	*-90%*	*1,256*	*229*	*-82%*	*126*	*229*	*83%*
Rate 3	*2*	*2*	*0%*	*1,600*	*520*	*-67%*	*800*	*260*	*-67%*
Year 3	**232**	**244**	**5%**	**13,462**	**8,964**	**-33%**	**58**	**37**	**-37%**
Rate 1	*220*	*241*	*10%*	*10,606*	*8,215*	*-23%*	*48*	*34*	*-29%*
Rate 2	*10*	*1*	*-90%*	*1,256*	*229*	*-82%*	*126*	*229*	*83%*
Rate 3	*2*	*2*	*0%*	*1,600*	*520*	*-67%*	*800*	*260*	*-67%*
Year 4	**232**	**244**	**5%**	**13,462**	**8,964**	**-33%**	**58**	**37**	**-37%**
Rate 1	*220*	*241*	*10%*	*10,606*	*8,215*	*-23%*	*48*	*34*	*-29%*
Rate 2	*10*	*1*	*-90%*	*1,256*	*229*	*-82%*	*126*	*229*	*83%*
Rate 3	*2*	*2*	*0%*	*1,600*	*520*	*-67%*	*800*	*260*	*-67%*
Year 5	**232**	**244**	**5%**	**13,462**	**8,964**	**-33%**	**58**	**37**	**-37%**
Rate 1	*220*	*241*	*10%*	*10,606*	*8,215*	*-23%*	*48*	*34*	*-29%*
Rate 2	*10*	*1*	*-90%*	*1,256*	*229*	*-82%*	*126*	*229*	*83%*
Rate 3	*2*	*2*	*0%*	*1,600*	*520*	*-67%*	*800*	*260*	*-67%*
Years 1-5 Total	**232**	**244**	**5%**	**62,033**	**39,545**	**-36%**	**58**	**37**	**-37%**

Table 6-6: 2013 FEVI Aggregate Main Extensions Profitability Index

2013 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.36	0.97	-28%
Years 1-5 Total	**1.36**	**0.97**	**-28%**

Notes:

- The actual main extension costs compared to forecast costs are $34,000 lower for FEVI representing a 9 percent cost variance. This variance is reasonable in that it is as accurate as possible without adding substantively to the administrative workload associated with estimating main extension costs.
- 7 FEVI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

6.3 *2013 FEI TOP 5 RESULTS*

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 6-7 & 6-8	Table 6-9 & 6-10	Table 6-11 & 6-12	Table 6-13 & 6-14	Table 6-15 & 6-16	Table 6-17
108 Avenue	272 Street	108 Avenue	101 Avenue	Princeton Avenue	Top 5 P.I. Results

Table 6-7: 2013 FEI Top 5 – 108th Avenue Costs

2013 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550002102	108th Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 179,474	$ 152,361	-15%
	Service lines and meters	$ -	$ 14,890	
	Year 1 Total	$ 179,474	$ 167,251	-7%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 20,870	$ -	-100%
	Year 2 Total	$ 20,870	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 44,196	$ -	-100%
	Year 3 Total	$ 44,196	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 44,196	$ -	-100%
	Year 4 Total	$ 44,196	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 20,870	$ -	-100%
	Year 5 Total	$ 20,870	$ -	-100%
Years 1-5 Total		**$309,605**	**$167,251**	**-46%**

Table 6-8: 2013 FEI Top 5 – 108th Avenue Attachments, Consumption and Use per Customer

2013 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550002102 108th Avenue	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**0**	**10**		**0**	**681**			**68**		
Rate 1	*0*	*10*		*0*	*681*			*68*		
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**17**	**27**	**59%**	**1,817**	**2,498**	**38%**	**107**	**93**	**-13%**	
Rate 1	*17*	*27*	*59%*	*1,817*	*2,498*	*38%*	*107*	*93*	*-13%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**53**	**63**	**19%**	**5,665**	**6,346**	**12%**	**107**	**101**	**-6%**	
Rate 1	*53*	*63*	*19%*	*5,665*	*6,346*	*12%*	*107*	*101*	*-6%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**89**	**99**	**11%**	**9,513**	**10,194**	**7%**	**107**	**103**	**-4%**	
Rate 1	*89*	*99*	*11%*	*9,513*	*10,194*	*7%*	*107*	*103*	*-4%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**106**	**116**	**9%**	**11,330**	**12,011**	**6%**	**107**	**104**	**-3%**	
Rate 1	*106*	*116*	*9%*	*11,330*	*12,011*	*6%*	*107*	*104*	*-3%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**106**	**116**	**9%**	**28,325**	**31,732**	**12%**	**107**	**104**	**-3%**	

Table 6-9: 2013 FEI Top 5 – 272 Street Costs

2013 TOP 5 MAIN EXTENSIONS - COSTS				
FEI 5550005647	272 Street	Cost of Installation ($)		
		Original Forecast	Actual	Variance %
Year 1	Mains	$ 145,000	$ 132,797	-8%
	Service lines and meters	$ 7,366	$ 2,978	-60%
	Year 1 Total	$ 152,366	$ 135,775	-11%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 6,138	$ -	-100%
	Year 3 Total	$ 6,138	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 6,138	$ -	-100%
	Year 5 Total	$ 6,138	$ -	-100%
Years 1-5 Total		**$164,642**	**$135,775**	**-18%**

Table 6-10: 2013 FEI Top 5 – 272 Street Attachments, Consumption and Use per Customer

2013 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI 5550005647 272 Street	Attachments			Consumption (GJ)			Use per Customer			
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**6**	**2**	**-67%**	**2,400**	**246**	**-90%**	**400**	**123**	**-69%**	
Rate 1	*0*	*2*		*0*	*246*			*123*		
Rate 2	*6*	*0*	*-100%*	*2,400*	*0*	*-100%*	*400*			
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**6**	**2**	**-67%**	**2,400**	**246**	**-90%**	**400**	**123**	**-69%**	
Rate 1	*0*	*2*		*0*	*246*			*123*		
Rate 2	*6*	*0*	*-100%*	*2,400*	*0*	*-100%*	*400*			
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**11**	**7**	**-36%**	**4,875**	**2,721**	**-44%**	**443**	**389**	**-12%**	
Rate 1	*0*	*2*		*0*	*246*			*123*		
Rate 2	*11*	*5*	*-55%*	*4,875*	*2,475*	*-49%*	*443*	*495*	*12%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**11**	**7**	**-36%**	**4,875**	**2,721**	**-44%**	**443**	**389**	**-12%**	
Rate 1	*0*	*2*		*0*	*246*			*123*		
Rate 2	*11*	*5*	*-55%*	*4,875*	*2,475*	*-49%*	*443*	*495*	*12%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**16**	**12**	**-25%**	**7,758**	**5,604**	**-28%**	**485**	**467**	**-4%**	
Rate 1	*0*	*2*		*0*	*246*			*123*		
Rate 2	*16*	*10*	*-38%*	*7,758*	*5,358*	*-31%*	*485*	*536*	*11%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**16**	**12**	**-25%**	**22,308**	**11,540**	**-48%**	**485**	**467**	**-4%**	

Table 6-11: 2013 FEI Top 5 – 108th Avenue Costs

2013 TOP 5 MAIN EXTENSIONS - COSTS				
FEI 5550006486 108th Avenue		Cost of Installation ($)		
		Original Forecast	Actual	Variance %
Year 1	Mains	$ 84,008	$ 122,983	46%
	Service lines and meters	$ 1,228	$ 22,335	1719%
	Year 1 Total	$ 85,236	$ 145,318	70%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$85,236**	**$145,318**	**70%**

Notes:

- Additional costs were incurred for flagging and traffic control for this project.
- This project provided service for a green house complex. The customer's heating systems had failed in mid-winter, as a result, temporary paving charges were incurred until final paving could be undertaken in spring.

Table 6-12: 2013 FEI Top 5 – 108th Avenue Attachments, Consumption and Use per Customer

2013 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550006486 108th Avenue	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**1**	**15**	**1400%**	**11,612**	**5,796**	**-50%**	**11,612**	**386**	**-97%**	
Rate 1	*0*	*13*		*0*	*720*			*55*		
Rate 2	*1*	*1*	*0%*	*11,612*	*25*	*-100%*	*11,612*	*25*	*-100%*	
Rate 3	*0*	*1*		*0*	*5,051*			*5,051*		
Year 2	**1**	**15**	**1400%**	**11,612**	**5,796**	**-50%**	**11,612**	**386**	**-97%**	
Rate 1	*0*	*13*		*0*	*720*			*55*		
Rate 2	*1*	*1*	*0%*	*11,612*	*25*	*-100%*	*11,612*	*25*	*-100%*	
Rate 3	*0*	*1*		*0*	*5,051*			*5,051*		
Year 3	**1**	**15**	**1400%**	**11,612**	**5,796**	**-50%**	**11,612**	**386**	**-97%**	
Rate 1	*0*	*13*		*0*	*720*			*55*		
Rate 2	*1*	*1*	*0%*	*11,612*	*25*	*-100%*	*11,612*	*25*	*-100%*	
Rate 3	*0*	*1*		*0*	*5,051*			*5,051*		
Year 4	**1**	**15**	**1400%**	**11,612**	**5,796**	**-50%**	**11,612**	**386**	**-97%**	
Rate 1	*0*	*13*		*0*	*720*			*55*		
Rate 2	*1*	*1*	*0%*	*11,612*	*25*	*-100%*	*11,612*	*25*	*-100%*	
Rate 3	*0*	*1*		*0*	*5,051*			*5,051*		
Year 5	**1**	**15**	**1400%**	**11,612**	**5,796**	**-50%**	**11,612**	**386**	**-97%**	
Rate 1	*0*	*13*		*0*	*720*			*55*		
Rate 2	*1*	*1*	*0%*	*11,612*	*25*	*-100%*	*11,612*	*25*	*-100%*	
Rate 3	*0*	*1*		*0*	*5,051*			*5,051*		
Years 1-5 Total	**1**	**15**	**1400%**	**58,060**	**28,979**	**-50%**	**11,612**	**386**	**-97%**	

Table 6-13: 2013 FEI Top 5 – 101st Avenue Costs

2013 TOP 5 MAIN EXTENSIONS - COSTS		Cost of Installation ($)		
FEI 5550006806	101st Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 71,750	$ 100,109	40%
	Service lines and meters	$ 17,187	$ 74,450	333%
	Year 1 Total	$ 88,937	$ 174,559	96%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 17,187	$ -	-100%
	Year 2 Total	$ 17,187	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 17,187	$ -	-100%
	Year 3 Total	$ 17,187	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 17,187	$ -	-100%
	Year 4 Total	$ 17,187	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 18,415	$ -	-100%
	Year 5 Total	$ 18,415	$ -	-100%
Years 1-5 Total		**$158,913**	**$174,559**	**10%**

Table 6-14: 2013 FEI Top 5 – 101st Avenue Attachments, Consumption and Use per Customer

2013 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER	Attachments			Consumption (GJ)			Use per Customer			Ramp-Up Factor
FEI 5550006806 101st Avenue	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**14**	**50**	**257%**	**1,453**	**2,535**	**74%**	**104**	**51**	**-51%**	
Rate 1	*14*	*50*	*257%*	*1,453*	*2,535*	*74%*	*104*	*51*	*-51%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**28**	**64**	**129%**	**2,906**	**3,988**	**37%**	**104**	**62**	**-40%**	
Rate 1	*28*	*64*	*129%*	*2,906*	*3,988*	*37%*	*104*	*62*	*-40%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**42**	**78**	**86%**	**4,359**	**5,441**	**25%**	**104**	**70**	**-33%**	
Rate 1	*42*	*78*	*86%*	*4,359*	*5,441*	*25%*	*104*	*70*	*-33%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**56**	**92**	**64%**	**5,812**	**6,894**	**19%**	**104**	**75**	**-28%**	
Rate 1	*56*	*92*	*64%*	*5,812*	*6,894*	*19%*	*104*	*75*	*-28%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**71**	**107**	**51%**	**7,369**	**8,451**	**15%**	**104**	**79**	**-24%**	
Rate 1	*71*	*107*	*51%*	*7,369*	*8,451*	*15%*	*104*	*79*	*-24%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**71**	**107**	**51%**	**21,899**	**27,311**	**25%**	**104**	**79**	**-24%**	

Table 6-15: 2013 FEI Top 5 – Princeton Avenue Costs

2013 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550007360	Princeton Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 77,900	$ 134,003	72%
	Service lines and meters	$ 20,870	$ 58,071	178%
	Year 1 Total	$ 98,770	$ 192,074	94%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 22,098	$ -	-100%
	Year 2 Total	$ 22,098	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 22,098	$ -	-100%
	Year 3 Total	$ 22,098	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 22,098	$ -	-100%
	Year 4 Total	$ 22,098	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 20,870	$ -	-100%
	Year 5 Total	$ 20,870	$ -	-100%
Years 1-5 Total		**$185,934**	**$192,074**	**3%**

Notes:

- An additional 150m of main was added to this project by field crews due to changes in the development layout and the subsequent required changes to accommodate new water and hydro locations.

Table 6-16: 2013 FEI Top 5 – Princeton Attachments, Consumption and Use per Customer

2013 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI 5550007360 Princeton Avenue	Attachments			Consumption (GJ)			Use per Customer			
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**17**	**39**	**129%**	**1,765**	**1,156**	**-34%**	**104**	**30**	**-71%**	
Rate 1	*17*	*39*	*129%*	*1,765*	*1,156*	*-34%*	*104*	*30*	*-71%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**35**	**57**	**63%**	**3,633**	**3,024**	**-17%**	**104**	**53**	**-49%**	
Rate 1	*35*	*57*	*63%*	*3,633*	*3,024*	*-17%*	*104*	*53*	*-49%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**53**	**75**	**42%**	**5,501**	**4,892**	**-11%**	**104**	**65**	**-37%**	
Rate 1	*53*	*75*	*42%*	*5,501*	*4,892*	*-11%*	*104*	*65*	*-37%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**71**	**93**	**31%**	**7,369**	**6,760**	**-8%**	**104**	**73**	**-30%**	
Rate 1	*71*	*93*	*31%*	*7,369*	*6,760*	*-8%*	*104*	*73*	*-30%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**88**	**110**	**25%**	**9,134**	**8,525**	**-7%**	**104**	**78**	**-25%**	
Rate 1	*88*	*110*	*25%*	*9,134*	*8,525*	*-7%*	*104*	*78*	*-25%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**88**	**110**	**25%**	**27,402**	**24,357**	**-11%**	**104**	**78**	**-25%**	

Table 6-17: 2013 FEI Top 5 Main Extensions Profitability Index

2013 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
108th Avenue	0.85	0.97	15%
272 Street	0.85	0.57	-33%
108th Avenue	2.21	0.44	-80%
101st Avenue	1.12	0.94	-16%
Princeton Avenue	1.29	0.84	-35%
Years 1-5 Total	**1.26**	**0.75**	**-41%**

6.4 *2013 FEVI TOP 5 RESULTS*

The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 6-18 & 6-19	Table 6-20 & 6-21	Table 6-22 & 6-23	Table 6-24 & 6-25	Table 6-26 & 6-27	Table 6-28
McCourt Road	Extension Road	Queenswood Drive	Wishart Road	Church Street	Top 5 P.I. Results

Table 6-18: 2013 FEVI Top 5 – McCourt Road Costs

2013 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550004759	McCourt Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 9,212	$ 30,751	234%
	Service lines and meters	$ 8,542	$ 7,015	-18%
	Year 1 Total	$ 17,754	$ 37,766	113%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 5,339	$ -	-100%
	Year 2 Total	$ 5,339	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 2,135	$ -	-100%
	Year 3 Total	$ 2,135	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$25,228**	**$37,766**	**50%**

Notes:

- This project was geo-priced in error and should have been manually estimated due to significant paving requirements. This was a training issue and has since been addressed.

Table 6-19: 2013 FEVI Top 5 – McCourt Road Attachments, Consumption and Use per Customer

2013 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550004759 McCourt Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**8**	**5**	**-38%**	**240**	**77**	**-68%**	**30**	**15**	**-49%**	
Rate 1	*8*	*5*	*-38%*	*240*	*77*	*-68%*	*30*	*15*	*-49%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**13**	**10**	**-23%**	**390**	**227**	**-42%**	**30**	**23**	**-24%**	
Rate 1	*13*	*10*	*-23%*	*390*	*227*	*-42%*	*30*	*23*	*-24%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**15**	**12**	**-20%**	**450**	**287**	**-36%**	**30**	**24**	**-20%**	
Rate 1	*15*	*12*	*-20%*	*450*	*287*	*-36%*	*30*	*24*	*-20%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**15**	**12**	**-20%**	**450**	**287**	**-36%**	**30**	**24**	**-20%**	
Rate 1	*15*	*12*	*-20%*	*450*	*287*	*-36%*	*30*	*24*	*-20%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**15**	**12**	**-20%**	**450**	**287**	**-36%**	**30**	**24**	**-20%**	
Rate 1	*15*	*12*	*-20%*	*450*	*287*	*-36%*	*30*	*24*	*-20%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**15**	**12**	**-20%**	**1,980**	**1,165**	**-41%**	**30**	**24**	**-20%**	

Table 6-20: 2013 FEVI Top 5 – Extension Road Costs

2013 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550006559	Extension Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 23,987	$ 39,069	63%
	Service lines and meters	$ 3,203	$ 9,821	207%
	Year 1 Total	$ 27,191	$ 48,890	80%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 7,474	$ -	-100%
	Year 2 Total	$ 7,474	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 14,948	$ -	-100%
	Year 3 Total	$ 14,948	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 3,203	$ -	-100%
	Year 4 Total	$ 3,203	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 7,474	$ -	-100%
	Year 5 Total	$ 7,474	$ -	-100%
Years 1-5 Total		**$60,291**	**$48,890**	**-19%**

Notes:

- Cost overages resulted from an un-foreseen road crossing due to building plan changes and lot additions after the project planning was complete. There were also significant repair costs due to damage to City curbs as a result of soil compaction and settling.

Table 6-21: 2013 FEVI Top 5 – Extension Road Attachments, Consumption and Use per Customer

2013 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI 5550006559 Extension Road	Attachments			Consumption (GJ)			Use per Customer			
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**3**	**7**	**133%**	**75**	**111**	**48%**	**25**	**16**	**-37%**	
Rate 1	*3*	*7*	*133%*	*75*	*111*	*48%*	*25*	*16*	*-37%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**10**	**14**	**40%**	**250**	**286**	**14%**	**25**	**20**	**-18%**	
Rate 1	*10*	*14*	*40%*	*250*	*286*	*14%*	*25*	*20*	*-18%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**24**	**28**	**17%**	**600**	**636**	**6%**	**25**	**23**	**-9%**	
Rate 1	*24*	*28*	*17%*	*600*	*636*	*6%*	*25*	*23*	*-9%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**27**	**31**	**15%**	**675**	**711**	**5%**	**25**	**23**	**-8%**	
Rate 1	*27*	*31*	*15%*	*675*	*711*	*5%*	*25*	*23*	*-8%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**34**	**38**	**12%**	**850**	**886**	**4%**	**25**	**23**	**-7%**	
Rate 1	*34*	*38*	*12%*	*850*	*886*	*4%*	*25*	*23*	*-7%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**34**	**38**	**12%**	**2,450**	**2,630**	**7%**	**25**	**23**	**-7%**	

Table 6-22: 2013 FEVI Top 5 – Queenswood Drive

2013 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550006786	Queenswood Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 57,839	$ 6,515	-89%
	Service lines and meters	$ 3,203	$ 4,209	31%
	Year 1 Total	$ 61,042	$ 10,724	-82%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$61,042**	**$10,724**	**-82%**

Notes:

- The costs for this project were reduced by a $39,000 customer CIAC. (Contribution in Aid of Construction)

Table 6-23: 2013 FEVI Top 5 – Queenswood Drive Attachments, Consumption and Use per Customer

2013 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550006786 Queenswood Drive	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**3**	**3**	**0%**	**467**	**464**	**-1%**	**156**	**155**	**-1%**	
Rate 1	*3*	*3*	*0%*	*467*	*464*	*-1%*	*156*	*155*	*-1%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**3**	**3**	**0%**	**467**	**464**	**-1%**	**156**	**155**	**-1%**	
Rate 1	*3*	*3*	*0%*	*467*	*464*	*-1%*	*156*	*155*	*-1%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**3**	**3**	**0%**	**467**	**464**	**-1%**	**156**	**155**	**-1%**	
Rate 1	*3*	*3*	*0%*	*467*	*464*	*-1%*	*156*	*155*	*-1%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**3**	**3**	**0%**	**467**	**464**	**-1%**	**156**	**155**	**-1%**	
Rate 1	*3*	*3*	*0%*	*467*	*464*	*-1%*	*156*	*155*	*-1%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**3**	**3**	**0%**	**467**	**464**	**-1%**	**156**	**155**	**-1%**	
Rate 1	*3*	*3*	*0%*	*467*	*464*	*-1%*	*156*	*155*	*-1%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**3**	**3**	**0%**	**2,335**	**2,319**	**-1%**	**156**	**155**	**-1%**	

Table 6-24: 2013 FEVI Top 5 – Wishart Costs

2013 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550007005	Wishart Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 117,253	$ 55,541	-53%
	Service lines and meters	$ 32,032	$ 19,642	-39%
	Year 1 Total	$ 149,285	$ 75,183	-50%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 29,897	$ -	-100%
	Year 2 Total	$ 29,897	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$179,182**	**$75,183**	**-58%**

Notes:

- The initial project costs were forecasted based on a requirement for steel main. After planning was completed it was determined that the project was able to accommodate a 60 mm PE main at a lower cost. In addition, there was a slight decrease in total pipe length requirements.

Table 6-25: 2013 FEVI Top 5 – Wishart Road Attachments, Consumption and Use per Customer

2013 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550007005 Wishart Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	30	14	-53%	1,285	53	-96%	43	4	-91%	
Rate 1	*30*	*14*	*-53%*	*1,285*	*53*	*-96%*	*43*	*4*	*-91%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	58	42	-28%	2,525	1,293	-49%	44	31	-29%	
Rate 1	*58*	*42*	*-28%*	*2,525*	*1,293*	*-49%*	*44*	*31*	*-29%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	58	42	-28%	2,525	1,293	-49%	44	31	-29%	
Rate 1	*58*	*42*	*-28%*	*2,525*	*1,293*	*-49%*	*44*	*31*	*-29%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	58	42	-28%	2,525	1,293	-49%	44	31	-29%	
Rate 1	*58*	*42*	*-28%*	*2,525*	*1,293*	*-49%*	*44*	*31*	*-29%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	58	42	-28%	2,525	1,293	-49%	44	31	-29%	
Rate 1	*58*	*42*	*-28%*	*2,525*	*1,293*	*-49%*	*44*	*31*	*-29%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	58	42	-28%	11,385	5,225	-54%	44	31	-29%	

1 **Table 6-26: 2013 FEVI Top 5 – Church Street Costs**

2013 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550007581	Church Street	Original Forecast	Actual	Variance %
Year 1	Mains	$ 24,735	$ 35,492	43%
	Service lines and meters	$ 1,068	$ 2,806	163%
	Year 1 Total	$ 25,803	$ 38,298	48%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$25,803**	**$38,298**	**48%**

2

3 Notes:

4 • This project incurred extra charges for directional drilling required to undercut existing pavement,
5 driveways and sidewalks.

Table 6-27: 2013 FEVI Top 5 – Church Street Attachments, Consumption and Use per Customer

2013 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550007581 Church Street	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**1**	**2**	**100%**	**700**	**520**	**-26%**	**700**	**260**	**-63%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*2*	*100%*	*700*	*520*	*-26%*	*700*	*260*	*-63%*	
Year 2	**1**	**2**	**100%**	**700**	**520**	**-26%**	**700**	**260**	**-63%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*2*	*100%*	*700*	*520*	*-26%*	*700*	*260*	*-63%*	
Year 3	**1**	**2**	**100%**	**700**	**520**	**-26%**	**700**	**260**	**-63%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*2*	*100%*	*700*	*520*	*-26%*	*700*	*260*	*-63%*	
Year 4	**1**	**2**	**100%**	**700**	**520**	**-26%**	**700**	**260**	**-63%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*2*	*100%*	*700*	*520*	*-26%*	*700*	*260*	*-63%*	
Year 5	**1**	**2**	**100%**	**700**	**520**	**-26%**	**700**	**260**	**-63%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*2*	*100%*	*700*	*520*	*-26%*	*700*	*260*	*-63%*	
Years 1-5 Total	**1**	**2**	**100%**	**3,500**	**2,601**	**-26%**	**700**	**260**	**-63%**	

Table 6-28: 2013 FEVI Top 5 Main Extensions Profitability Index

2013 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
McCourt Road	1.08	0.37	-66%
Extension Road	0.91	0.75	-18%
Queenswood Drive	0.80	1.02	27%
Wishart Road	0.91	0.90	-1%
Church Street	1.30	0.74	-43%
Years 1-5 Total	**1.00**	**0.75**	**-25%**

7. 2012 MAIN EXTENSIONS

The following section summarizes the aggregate and top 5 results for the 2012 main extensions including vertical subdivisions.

- The forecasted results contained in this section are based on projects for the 2012 gas year (November 01, 2011 to October 31, 2012).
- The actual results in this section are from November 01, 2011 to October 31, 2012.
- The tables included in this section contain a comparison of forecasted and actual costs, attachments and consumption for Year 1.
- For the projects included in the Top 5 section, the Companies have provided explanations where unique circumstances exist. For those projects that do not include explanations, variances are a result of labour or material cost differences or the challenges in accurately forecasting attachments and consumption.
- The grey shading in the tables below is used to indicate a forecast year.
- The 2012 main extension data tables as well as future report tables reflect the expanded rate class breakdown as discussed in Section 1.

7.1 *2012 FEI SAMPLE RESULTS*

The tables below summarize the sample aggregate 2012 main extension results for FEI.

Table 7-1: 2012 FEI Aggregate Main Extensions Costs

2012 SAMPLE MAIN EXTENSIONS - COSTS				
		Cost of Installation ($)		
FEI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 585,584	$ 713,526	22%
	Service lines and meters	$ 246,400	$ 607,322	146%
	Year 1 Total	$ 831,984	$ 1,320,848	59%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 106,805	$ 362,485	239%
	Year 2 Total	$ 106,805	$ 362,485	239%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 99,310	$ -	-100%
	Year 3 Total	$ 99,310	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 76,824	$ -	-100%
	Year 4 Total	$ 76,824	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 51,529	$ -	-100%
	Year 5 Total	$ 51,529	$ -	-100%
Years 1-5 Total		**$1,166,451**	**$1,683,333**	**44%**

Table 7-2: 2012 FEI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2012 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
	Attachments			Consumption (GJ)			Use per Customer		
FEI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	**263**	**382**	**45%**	**101,576**	**52,841**	**-48%**	**386**	**138**	**-64%**
Rate 1	*173*	*290*	*68%*	*20,640*	*13,126*	*-36%*	*119*	*45*	*-62%*
Rate 2	*88*	*90*	*2%*	*41,307*	*19,742*	*-52%*	*469*	*219*	*-53%*
Rate 3	*2*	*2*	*0%*	*39,629*	*19,973*	*-50%*	*19,815*	*9,987*	*-50%*
Year 2	**377**	**610**	**62%**	**111,841**	**70,456**	**-37%**	**297**	**116**	**-61%**
Rate 1	*270*	*509*	*89%*	*29,246*	*30,363*	*4%*	*108*	*60*	*-45%*
Rate 2	*105*	*99*	*-6%*	*42,966*	*20,120*	*-53%*	*409*	*203*	*-50%*
Rate 3	*2*	*2*	*0%*	*39,629*	*19,973*	*-50%*	*19,815*	*9,987*	*-50%*
Year 3	**483**	**716**	**48%**	**122,484**	**81,099**	**-34%**	**254**	**113**	**-55%**
Rate 1	*373*	*612*	*64%*	*37,536*	*38,653*	*3%*	*101*	*63*	*-37%*
Rate 2	*108*	*102*	*-6%*	*45,319*	*22,473*	*-50%*	*420*	*220*	*-47%*
Rate 3	*2*	*2*	*0%*	*39,629*	*19,973*	*-50%*	*19,815*	*9,987*	*-50%*
Year 4	**565**	**798**	**41%**	**129,157**	**87,772**	**-32%**	**229**	**110**	**-52%**
Rate 1	*452*	*691*	*53%*	*41,856*	*42,973*	*3%*	*93*	*62*	*-33%*
Rate 2	*111*	*105*	*-5%*	*47,672*	*24,826*	*-48%*	*429*	*236*	*-45%*
Rate 3	*2*	*2*	*0%*	*39,629*	*19,973*	*-50%*	*19,815*	*9,987*	*-50%*
Year 5	**620**	**853**	**38%**	**135,819**	**94,434**	**-30%**	**219**	**111**	**-49%**
Rate 1	*496*	*735*	*48%*	*45,452*	*46,569*	*2%*	*92*	*63*	*-31%*
Rate 2	*122*	*116*	*-5%*	*50,738*	*27,892*	*-45%*	*416*	*240*	*-42%*
Rate 3	*2*	*2*	*0%*	*39,629*	*19,973*	*-50%*	*19,815*	*9,987*	*-50%*
Years 1-5 Total	**620**	**853**	**38%**	**600,877**	**386,602**	**-36%**	**219**	**111**	**-49%**

Table 7-3: 2012 FEI Aggregate Main Extensions Profitability Index

2012 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	2.41	1.46	-40%
Years 1-5 Total	**2.41**	**1.46**	**-40%**

Notes:

- The actual main extension costs compared to forecast costs are $60,000 higher for FEI representing a 10 percent cost variance. This variance is reasonable in that it is as accurate as possible without adding substantively to the administrative workload associated with estimating main extension costs.
- 11 FEI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

7.2 2012 FEVI SAMPLE RESULTS

The tables below summarize the sample aggregate 2012 main extension results for FEVI.

Table 7-4: 2012 FEVI Aggregate Main Extensions Costs

2012 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEVI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 367,763	$ 366,389	0%
	Service lines and meters	$ 111,465	$ 190,662	71%
	Year 1 Total	$ 479,228	$ 557,051	16%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 37,559	$ 1,478	-96%
	Year 2 Total	$ 37,559	$ 1,478	-96%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 27,866	$ -	-100%
	Year 3 Total	$ 27,866	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 12,116	$ -	-100%
	Year 4 Total	$ 12,116	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 12,116	$ -	-100%
	Year 5 Total	$ 12,116	$ -	-100%
Years 1-5 Total		**$568,885**	**$558,529**	**-2%**

Table 7-5: 2012 FEVI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2012 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
FEVI	Attachments			Consumption (GJ)			Use per Customer		
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	**92**	**129**	**40%**	**9,845**	**6,466**	**-34%**	**107**	**50**	**-53%**
Rate 1	*82*	*117*	*43%*	*4,330*	*2,860*	*-34%*	*53*	*24*	*-54%*
Rate 2	*5*	*8*	*60%*	*710*	*1,495*	*111%*	*142*	*187*	*32%*
Rate 3	*5*	*4*	*-20%*	*4,805*	*2,111*	*-56%*	*961*	*528*	*-45%*
Year 2	**123**	**130**	**6%**	**11,482**	**6,472**	**-44%**	**93**	**50**	**-47%**
Rate 1	*113*	*118*	*4%*	*5,967*	*2,866*	*-52%*	*53*	*24*	*-54%*
Rate 2	*5*	*8*	*60%*	*710*	*1,495*	*111%*	*142*	*187*	*32%*
Rate 3	*5*	*4*	*-20%*	*4,805*	*2,111*	*-56%*	*961*	*528*	*-45%*
Year 3	**146**	**153**	**5%**	**13,130**	**8,120**	**-38%**	**90**	**53**	**-41%**
Rate 1	*135*	*140*	*4%*	*7,415*	*4,314*	*-42%*	*55*	*31*	*-44%*
Rate 2	*6*	*9*	*50%*	*910*	*1,695*	*86%*	*152*	*188*	*24%*
Rate 3	*5*	*4*	*-20%*	*4,805*	*2,111*	*-56%*	*961*	*528*	*-45%*
Year 4	**156**	**163**	**4%**	**13,595**	**8,585**	**-37%**	**87**	**53**	**-40%**
Rate 1	*145*	*150*	*3%*	*7,880*	*4,779*	*-39%*	*54*	*32*	*-41%*
Rate 2	*6*	*9*	*50%*	*910*	*1,695*	*86%*	*152*	*188*	*24%*
Rate 3	*5*	*4*	*-20%*	*4,805*	*2,111*	*-56%*	*961*	*528*	*-45%*
Year 5	**166**	**173**	**4%**	**13,925**	**8,915**	**-36%**	**84**	**52**	**-39%**
Rate 1	*155*	*160*	*3%*	*8,210*	*5,109*	*-38%*	*53*	*32*	*-40%*
Rate 2	*6*	*9*	*50%*	*910*	*1,695*	*86%*	*152*	*188*	*24%*
Rate 3	*5*	*4*	*-20%*	*4,805*	*2,111*	*-56%*	*961*	*528*	*-45%*
Years 1-5 Total	**166**	**173**	**4%**	**61,977**	**38,558**	**-38%**	**84**	**52**	**-39%**

Table 7-6: 2012 FEI Aggregate Main Extensions Profitability Index

2012 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.39	1.09	-21%
Years 1-5 Total	**1.39**	**1.09**	**-21%**

Notes:

- The actual main extension costs compared to forecast costs are $18,000 lower for FEVI representing a 3 percent cost variance. This variance is reasonable in that it is as accurate as possible without adding substantively to the administrative workload associated with estimating main extension costs.
- 10 FEVI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

7.3 2012 FEI TOP 5 RESULTS

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 7-7 & 7-8	Table 7-9 & 7-10	Table 7-11 & 7-12	Table 7-13 & 7-14	Table 7-15 & 7-16	Table 7-17
201 Street	Pandosy Street	E. Kent Avenue	Cordova Way	Fremont Street	Top 5 P.I. Results

Table 7-7: 2012 FEI Top 5 – 201st Street Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550003835	201 Street	Original Forecast	Actual	Variance %
Year 1	Mains	$ 42,131	$ 73,935	75%
	Service lines and meters	$ 937	$ 4,770	409%
	Year 1 Total	$ 43,068	$ 78,704	83%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 937	$ -	-100%
	Year 2 Total	$ 937	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$44,005**	**$78,704**	**79%**

Table 7-8: 2012 FEI Top 5 – 201st Street Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550003835 201 Street	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**1**	**3**	**200%**	**1,998**	**2,308**	**16%**	**1,998**	**769**	**-61%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*1*	*3*	*200%*	*1,998*	*2,308*	*16%*	*1,998*	*769*	*-61%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**2**	**3**	**50%**	**3,996**	**2,308**	**-42%**	**1,998**	**769**	**-61%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*3*	*50%*	*3,996*	*2,308*	*-42%*	*1,998*	*769*	*-61%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**2**	**3**	**50%**	**3,996**	**2,308**	**-42%**	**1,998**	**769**	**-61%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*3*	*50%*	*3,996*	*2,308*	*-42%*	*1,998*	*769*	*-61%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**2**	**3**	**50%**	**3,996**	**2,308**	**-42%**	**1,998**	**769**	**-61%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*3*	*50%*	*3,996*	*2,308*	*-42%*	*1,998*	*769*	*-61%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**2**	**3**	**50%**	**3,996**	**2,308**	**-42%**	**1,998**	**769**	**-61%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*3*	*50%*	*3,996*	*2,308*	*-42%*	*1,998*	*769*	*-61%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**2**	**3**	**50%**	**17,982**	**11,540**	**-36%**	**1,998**	**769**	**-61%**	

Notes:

- Due to a damaged main, the original tie in location for this project had to be moved resulting in additional labour and material charges.
- The running line for this main also ended up being in direct conflict with Telus services which had been moved after the initial planning of the project.
- Several conflicts with existing water lines were encountered resulting in additional labour charges.

Table 7-9: 2012 FEI Top 5 – Pandosy Street Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS		Cost of Installation ($)		
FEI 5550004072	Pandosy Street	Original Forecast	Actual	Variance %
Year 1	Mains	$ 60,000	$ 54,841	-9%
	Service lines and meters	$ 937	$ 3,180	239%
	Year 1 Total	$ 60,937	$ 58,021	-5%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$60,937	$58,021	-5%

Table 7-10: 2012 FEI Top 5 – Pandosy Street Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER	Attachments			Consumption (GJ)			Use per Customer			Ramp-Up Factor
FEI 5550004072 Pandosy Street	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**1**	**2**	**100%**	**36,864**	**16,533**	**-55%**	**36,864**	**8,267**	**-78%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*1*		*0*	*4,521*			*4,521*		
Rate 3	*1*	*1*	*0%*	*36,864*	*12,012*	*-67%*	*36,864*	*12,012*	*-67%*	
Year 2	**1**	**2**	**100%**	**36,864**	**16,533**	**-55%**	**36,864**	**8,267**	**-78%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*1*		*0*	*4,521*			*4,521*		
Rate 3	*1*	*1*	*0%*	*36,864*	*12,012*	*-67%*	*36,864*	*12,012*	*-67%*	
Year 3	**1**	**2**	**100%**	**36,864**	**16,533**	**-55%**	**36,864**	**8,267**	**-78%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*1*		*0*	*4,521*			*4,521*		
Rate 3	*1*	*1*	*0%*	*36,864*	*12,012*	*-67%*	*36,864*	*12,012*	*-67%*	
Year 4	**1**	**2**	**100%**	**36,864**	**16,533**	**-55%**	**36,864**	**8,267**	**-78%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*1*		*0*	*4,521*			*4,521*		
Rate 3	*1*	*1*	*0%*	*36,864*	*12,012*	*-67%*	*36,864*	*12,012*	*-67%*	
Year 5	**1**	**2**	**100%**	**36,864**	**16,533**	**-55%**	**36,864**	**8,267**	**-78%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*1*		*0*	*4,521*			*4,521*		
Rate 3	*1*	*1*	*0%*	*36,864*	*12,012*	*-67%*	*36,864*	*12,012*	*-67%*	
Years 1-5 Total	**1**	**2**	**100%**	**184,320**	**82,665**	**-55%**	**36,864**	**8,267**	**-78%**	

Table 7-11: 2012 FEI Top 5 – E. Kent Avenue Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550005506	E Kent Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 66,965	$ 77,867	16%
	Service lines and meters	$ 14,990	$ 4,770	-68%
	Year 1 Total	$ 81,955	$ 82,637	1%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$81,955	$82,637	1%

Table 7-12: 2012 FEI Top 5 – E. Kent Avenue Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550005506 E Kent Avenue	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**16**	**3**	**-81%**	**4,864**	**898**	**-82%**	**304**	**299**	**-2%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*2*	*-88%*	*4,864*	*284*	*-94%*	*304*	*142*	*-53%*	
Rate 3	*0*	*1*		*0*	*614*			*614*		
Year 2	**16**	**3**	**-81%**	**4,864**	**898**	**-82%**	**304**	**299**	**-2%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*2*	*-88%*	*4,864*	*284*	*-94%*	*304*	*142*	*-53%*	
Rate 3	*0*	*1*		*0*	*614*			*614*		
Year 3	**16**	**3**	**-81%**	**4,864**	**898**	**-82%**	**304**	**299**	**-2%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*2*	*-88%*	*4,864*	*284*	*-94%*	*304*	*142*	*-53%*	
Rate 3	*0*	*1*		*0*	*614*			*614*		
Year 4	**16**	**3**	**-81%**	**4,864**	**898**	**-82%**	**304**	**299**	**-2%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*2*	*-88%*	*4,864*	*284*	*-94%*	*304*	*142*	*-53%*	
Rate 3	*0*	*1*		*0*	*614*			*614*		
Year 5	**16**	**3**	**-81%**	**4,864**	**898**	**-82%**	**304**	**299**	**-2%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*2*	*-88%*	*4,864*	*284*	*-94%*	*304*	*142*	*-53%*	
Rate 3	*0*	*1*		*0*	*614*			*614*		
Years 1-5 Total	**16**	**3**	**-81%**	**24,320**	**4,490**	**-82%**	**304**	**299**	**-2%**	

Table 7-13: 2012 FEI Top 5 – Cordova Way Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550005581	Cordova Way	Original Forecast	Actual	Variance %
Year 1	Mains	$ 140,283	$ 102,168	-27%
	Service lines and meters	$ 2,811	$ 1,590	-43%
	Year 1 Total	$ 143,094	$ 103,757	-27%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 2,811	$ -	-100%
	Year 2 Total	$ 2,811	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 2,811	$ -	-100%
	Year 3 Total	$ 2,811	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 937	$ -	-100%
	Year 4 Total	$ 937	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 1,874	$ -	-100%
	Year 5 Total	$ 1,874	$ -	-100%
Years 1-5 Total		**$151,526**	**$103,757**	**-32%**

Table 7-14: 2012 FEI Top 5 – Cordova Way Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI	Attachments			Consumption (GJ)			Use per Customer			
5550005581 Cordova Way	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**3**	**1**	**-67%**	**1,050**	**113**	**-89%**	**350**	**113**	**-68%**	
Rate 1	*0*	*1*		*0*	*113*			*113*		
Rate 2	*3*	*0*	*-100%*	*1,050*	*0*	*-100%*	*350*			
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**6**	**1**	**-83%**	**2,182**	**113**	**-95%**	**364**	**113**	**-69%**	
Rate 1	*0*	*1*		*0*	*113*			*113*		
Rate 2	*6*	*0*	*-100%*	*2,182*	*0*	*-100%*	*364*			
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**9**	**4**	**-56%**	**3,282**	**1,213**	**-63%**	**365**	**303**	**-17%**	
Rate 1	*0*	*1*		*0*	*113*			*113*		
Rate 2	*9*	*3*	*-67%*	*3,282*	*1,100*	*-66%*	*365*	*367*	*1%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**10**	**5**	**-50%**	**3,682**	**1,613**	**-56%**	**368**	**323**	**-12%**	
Rate 1	*0*	*1*		*0*	*113*			*113*		
Rate 2	*10*	*4*	*-60%*	*3,682*	*1,500*	*-59%*	*368*	*375*	*2%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**12**	**7**	**-42%**	**4,482**	**2,413**	**-46%**	**374**	**345**	**-8%**	
Rate 1	*0*	*1*		*0*	*113*			*113*		
Rate 2	*12*	*6*	*-50%*	*4,482*	*2,300*	*-49%*	*374*	*383*	*3%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**12**	**7**	**-42%**	**14,678**	**5,465**	**-63%**	**374**	**345**	**-8%**	

Table 7-15: 2012 FEI Top 5 – Fremont Street Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550005794	Fremont Street	Original Forecast	Actual	Variance %
Year 1	Mains	$ 94,046	$ 87,366	-7%
	Service lines and meters	$ 1,874	$ 47,695	2445%
	Year 1 Total	$ 95,920	$ 135,062	41%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 937	$ -	-100%
	Year 2 Total	$ 937	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 2,811	$ -	-100%
	Year 3 Total	$ 2,811	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 2,811	$ -	-100%
	Year 4 Total	$ 2,811	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 2,811	$ -	-100%
	Year 5 Total	$ 2,811	$ -	-100%
Years 1-5 Total		$105,288	$135,062	28%

Table 7-16: 2012 FEI Top 5 – Fremont Street Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEI 5550005794 Fremont Street	Attachments			Consumption (GJ)			Use per Customer			
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**2**	**30**	**1400%**	**1,421**	**4,515**	**218%**	**711**	**151**	**-79%**	
Rate 1	*0*	*1*		*0*	*470*			*470*		
Rate 2	*2*	*29*	*1350%*	*1,421*	*4,045*	*185%*	*711*	*139*	*-80%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**3**	**30**	**900%**	**2,078**	**4,515**	**117%**	**693**	**151**	**-78%**	
Rate 1	*0*	*1*		*0*	*470*			*470*		
Rate 2	*3*	*29*	*867%*	*2,078*	*4,045*	*95%*	*693*	*139*	*-80%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**6**	**33**	**450%**	**4,431**	**6,868**	**55%**	**739**	**208**	**-72%**	
Rate 1	*0*	*1*		*0*	*470*			*470*		
Rate 2	*6*	*32*	*433%*	*4,431*	*6,398*	*44%*	*739*	*200*	*-73%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**9**	**36**	**300%**	**6,784**	**9,221**	**36%**	**754**	**256**	**-66%**	
Rate 1	*0*	*1*		*0*	*470*			*470*		
Rate 2	*9*	*35*	*289%*	*6,784*	*8,751*	*29%*	*754*	*250*	*-67%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**12**	**39**	**225%**	**9,137**	**11,574**	**27%**	**761**	**297**	**-61%**	
Rate 1	*0*	*1*		*0*	*470*			*470*		
Rate 2	*12*	*38*	*217%*	*9,137*	*11,104*	*22%*	*761*	*292*	*-62%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**12**	**39**	**225%**	**23,851**	**36,693**	**54%**	**761**	**297**	**-61%**	

Table 7-17: 2012 FEI Top 5 Main Extensions Profitability Index

2012 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
201 Street	1.48	0.53	-64%
Pandosy Street	9.20	4.24	-54%
E Kent Avenue	1.55	0.24	-84%
Cordova Way	0.80	0.27	-66%
Fremont Street	0.98	0.96	-2%
Years 1-5 Total	**2.80**	**1.25**	**-55%**

7.4 2012 FEVI TOP 5 RESULTS

The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 7-18 & 7-19	Table 7-20 & 7-21	Table 7-22 & 7-23	Table 7-24 & 7-25	Table 7-26 & 7-27	Table 7-28
Arbot Road	Small Road	Rutherford Road	Bowen Road	Delamere Road	Top 5 P.I. Results

Table 7-18: 2012 FEVI Top 5 – Arbot Road Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550004441	Arbot Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 108,738	$ 128,245	18%
	Service lines and meters	$ 3,635	$ 32,516	795%
	Year 1 Total	$ 112,372	$ 160,761	43%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 6,058	$ -	-100%
	Year 2 Total	$ 6,058	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 6,058	$ -	-100%
	Year 3 Total	$ 6,058	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 8,481	$ -	-100%
	Year 4 Total	$ 8,481	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 6,058	$ -	-100%
	Year 5 Total	$ 6,058	$ -	-100%
Years 1-5 Total		**$139,027**	**$160,761**	**16%**

Table 7-19: 2012 FEVI Top 5 – Arbot Road Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550004441 Arbot Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**3**	**22**	**633%**	**150**	**745**	**397%**	**50**	**34**	**-32%**	
Rate 1	*3*	*21*	*600%*	*150*	*321*	*114%*	*50*	*15*	*-69%*	
Rate 2	*0*	*1*		*0*	*424*			*424*		
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**8**	**22**	**175%**	**400**	**745**	**86%**	**50**	**34**	**-32%**	
Rate 1	*8*	*21*	*163%*	*400*	*321*	*-20%*	*50*	*15*	*-69%*	
Rate 2	*0*	*1*		*0*	*424*			*424*		
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**13**	**27**	**108%**	**650**	**995**	**53%**	**50**	**37**	**-26%**	
Rate 1	*13*	*26*	*100%*	*650*	*571*	*-12%*	*50*	*22*	*-56%*	
Rate 2	*0*	*1*		*0*	*424*			*424*		
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**20**	**34**	**70%**	**1,000**	**1,345**	**35%**	**50**	**40**	**-21%**	
Rate 1	*20*	*33*	*65%*	*1,000*	*921*	*-8%*	*50*	*28*	*-44%*	
Rate 2	*0*	*1*		*0*	*424*			*424*		
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**25**	**39**	**56%**	**1,250**	**1,595**	**28%**	**50**	**41**	**-18%**	
Rate 1	*25*	*38*	*52%*	*1,250*	*1,171*	*-6%*	*50*	*31*	*-38%*	
Rate 2	*0*	*1*		*0*	*424*			*424*		
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**25**	**39**	**56%**	**3,450**	**5,425**	**57%**	**50**	**41**	**-18%**	

Table 7-20: 2012 FEVI Top 5 – Small Road Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550004572	Small Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 23,350	$ 29,972	28%
	Service lines and meters	$ 1,212	$ 1,478	22%
	Year 1 Total	$ 24,562	$ 31,450	28%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 1,212	$ -	-100%
	Year 3 Total	$ 1,212	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$25,773**	**$31,450**	**22%**

Table 7-21: 2012 FEVI Top 5 – Small Road Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550004572 Small Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**1**	**1**	**0%**	**288**	**364**	**26%**	**288**	**364**	**26%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*1*	*1*	*0%*	*288*	*364*	*26%*	*288*	*364*	*26%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**1**	**1**	**0%**	**288**	**364**	**26%**	**288**	**364**	**26%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*1*	*1*	*0%*	*288*	*364*	*26%*	*288*	*364*	*26%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**2**	**2**	**0%**	**488**	**564**	**16%**	**244**	**282**	**16%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*488*	*564*	*16%*	*244*	*282*	*16%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**2**	**2**	**0%**	**488**	**564**	**16%**	**244**	**282**	**16%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*488*	*564*	*16%*	*244*	*282*	*16%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**2**	**2**	**0%**	**488**	**564**	**16%**	**244**	**282**	**16%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*488*	*564*	*16%*	*244*	*282*	*16%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**2**	**2**	**0%**	**2,040**	**2,420**	**19%**	**244**	**282**	**16%**	

Notes:

- A directional drill underneath a Highway and extra depth requirements resulted in driving actual costs higher than forecast.

Table 7-22: 2012 FEVI Top 5 – Rutherford Road Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550005404	Rutherford Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 52,525	$ 62,901	20%
	Service lines and meters	$ 12,116	$ 38,428	217%
	Year 1 Total	$ 64,641	$ 101,329	57%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 14,539	$ -	-100%
	Year 2 Total	$ 14,539	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 9,693	$ -	-100%
	Year 3 Total	$ 9,693	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 9,693	$ -	-100%
	Year 4 Total	$ 9,693	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 12,116	$ -	-100%
	Year 5 Total	$ 12,116	$ -	-100%
Years 1-5 Total		$110,681	$101,329	-8%

Table 7-23: 2012 FEVI Top 5 – Rutherford Road Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										Ramp-Up Factor
FEVI	Attachments			Consumption (GJ)			Use per Customer			
5550005404 Rutherford Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**10**	**26**	**160%**	**396**	**403**	**2%**	**40**	**16**	**-61%**	
Rate 1	*10*	*26*	*160%*	*396*	*403*	*2%*	*40*	*16*	*-61%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**22**	**26**	**18%**	**1,004**	**403**	**-60%**	**46**	**16**	**-66%**	
Rate 1	*22*	*26*	*18%*	*1,004*	*403*	*-60%*	*46*	*16*	*-66%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**30**	**34**	**13%**	**1,321**	**720**	**-45%**	**44**	**21**	**-52%**	
Rate 1	*30*	*34*	*13%*	*1,321*	*720*	*-45%*	*44*	*21*	*-52%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**38**	**42**	**11%**	**1,638**	**1,037**	**-37%**	**43**	**25**	**-43%**	
Rate 1	*38*	*42*	*11%*	*1,638*	*1,037*	*-37%*	*43*	*25*	*-43%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**48**	**52**	**8%**	**2,034**	**1,433**	**-30%**	**42**	**28**	**-35%**	
Rate 1	*48*	*52*	*8%*	*2,034*	*1,433*	*-30%*	*42*	*28*	*-35%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**48**	**52**	**8%**	**6,393**	**3,996**	**-37%**	**42**	**28**	**-35%**	

Table 7-24: 2012 FEVI Top 5 – Bowen Road Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550005574	Bowen Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 31,520	$ 31,041	-2%
	Service lines and meters	$ 16,962	$ 7,390	-56%
	Year 1 Total	$ 48,482	$ 38,431	-21%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 12,116	$ -	-100%
	Year 2 Total	$ 12,116	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$60,598**	**$38,431**	**-37%**

Table 7-25: 2012 FEVI Top 5 – Bowen Road Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER	Attachments			Consumption (GJ)			Use per Customer			Ramp-Up Factor
FEVI 5550005574 Bowen Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**14**	**5**	**-64%**	**420**	**5,367**	**1178%**	**30**	**1,073**	**3478%**	
Rate 1	*14*	*0*	*-100%*	*420*	*0*	*-100%*	*30*			
Rate 2	*0*	*3*		*0*	*966*			*322*		
Rate 3	*0*	*2*		*0*	*4,401*			*2,201*		
Year 2	**24**	**5**	**-79%**	**720**	**5,367**	**645%**	**30**	**1,073**	**3478%**	
Rate 1	*24*	*0*	*-100%*	*720*	*0*	*-100%*	*30*			
Rate 2	*0*	*3*		*0*	*966*			*322*		
Rate 3	*0*	*2*		*0*	*4,401*			*2,201*		
Year 3	**24**	**5**	**-79%**	**720**	**5,367**	**645%**	**30**	**1,073**	**3478%**	
Rate 1	*24*	*0*	*-100%*	*720*	*0*	*-100%*	*30*			
Rate 2	*0*	*3*		*0*	*966*			*322*		
Rate 3	*0*	*2*		*0*	*4,401*			*2,201*		
Year 4	**24**	**5**	**-79%**	**720**	**5,367**	**645%**	**30**	**1,073**	**3478%**	
Rate 1	*24*	*0*	*-100%*	*720*	*0*	*-100%*	*30*			
Rate 2	*0*	*3*		*0*	*966*			*322*		
Rate 3	*0*	*2*		*0*	*4,401*			*2,201*		
Year 5	**24**	**5**	**-79%**	**720**	**5,367**	**645%**	**30**	**1,073**	**3478%**	
Rate 1	*24*	*0*	*-100%*	*720*	*0*	*-100%*	*30*			
Rate 2	*0*	*3*		*0*	*966*			*322*		
Rate 3	*0*	*2*		*0*	*4,401*			*2,201*		
Years 1-5 Total	**24**	**5**	**-79%**	**3,300**	**26,835**	**713%**	**30**	**1,073**	**3478%**	

Table 7-26: 2012 FEVI Top 5 – Delamere Road Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550006162	Delamere Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 13,558	$ 33,830	150%
	Service lines and meters	$ 3,635	$ 5,912	63%
	Year 1 Total	$ 17,192	$ 39,742	131%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$17,192**	**$39,742**	**131%**

Table 7-27: 2012 FEVI Top 5 – Delamere Road Attachments, Consumption and Use per Customer

2012 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER	Attachments			Consumption (GJ)			Use per Customer			Ramp-Up Factor
FEVI 5550006162 Delamere Road	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	0%
Year 1	**3**	**4**	**33%**	**190**	**141**	**-26%**	**63**	**35**	**-44%**	
Rate 1	*3*	*4*	*33%*	*190*	*141*	*-26%*	*63*	*35*	*-44%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**3**	**4**	**33%**	**190**	**141**	**-26%**	**63**	**35**	**-44%**	
Rate 1	*3*	*4*	*33%*	*190*	*141*	*-26%*	*63*	*35*	*-44%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**3**	**4**	**33%**	**190**	**141**	**-26%**	**63**	**35**	**-44%**	
Rate 1	*3*	*4*	*33%*	*190*	*141*	*-26%*	*63*	*35*	*-44%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**3**	**4**	**33%**	**190**	**141**	**-26%**	**63**	**35**	**-44%**	
Rate 1	*3*	*4*	*33%*	*190*	*141*	*-26%*	*63*	*35*	*-44%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**3**	**4**	**33%**	**190**	**141**	**-26%**	**63**	**35**	**-44%**	
Rate 1	*3*	*4*	*33%*	*190*	*141*	*-26%*	*63*	*35*	*-44%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**3**	**4**	**33%**	**950**	**705**	**-26%**	**63**	**35**	**-44%**	

Notes:

- The running line for this main was in conflict with asphalt for 143 meters. As a result, significant pavement costs were incurred that were not captured by the original geo-priced forecast.

Table 7-28: 2012 FEVI Top 5 Main Extensions Profitability Index

2012 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	**Original Years 1-5 Forecast**	**Re-calculated PI with actual data**	**Variance %**
Arbot Road	0.80	0.54	-32%
Small Road	1.31	1.24	-5%
Rutherford Road	0.92	0.57	-38%
Bowen Road	0.80	7.66	855%
Delamere Road	0.80	0.13	-83%
Years 1-5 Total	**0.93**	**2.03**	**119%**

8. 2011 MAIN EXTENSIONS

The following section summarizes the aggregate and top 5 results for the 2011 main extensions including vertical subdivisions.

- The forecasted results contained in this section are based on projects for the 2011 gas year (November 01, 2010 to October 31, 2011).
- The actual results in this section are from November 01, 2010 to October 31, 2012.
- The tables included in this section contain a comparison of forecasted and actual costs, attachments and consumption for Year 2.
- For the projects included in the Top 5 section, the Companies have provided explanations where unique circumstances exist. For those projects that do not include explanations, variances are a result of labour or material cost differences or the challenges in accurately forecasting attachments and consumption.
- The grey shading in the tables below is used to indicate a forecast year.

8.1 *2011 FEI SAMPLE RESULTS*

The tables below summarize the sample aggregate 2011 main extension results for FEI.

Table 8-1: 2011 FEI Aggregate Main Extensions Costs

2011 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 634,248	$ 727,525	15%
	Service lines and meters	$ 415,268	$ 678,507	63%
	Year 1 Total	$ 1,049,516	$ 1,406,032	34%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 165,872	$ 1,560	-99%
	Year 2 Total	$ 165,872	$ 1,560	-99%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 109,405	$ 205,892	88%
	Year 3 Total	$ 109,405	$ 205,892	88%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 59,996	$ -	-100%
	Year 4 Total	$ 59,996	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 90,583	$ -	-100%
	Year 5 Total	$ 90,583	$ -	-100%
Years 1-5 Total		**$1,475,371**	**$1,613,483**	**9%**

Table 8-2: 2011 FEI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2011 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
	Attachments			Consumption (GJ)			Use per Customer		
FEI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	353	435	23%	45,968	47,982	4%	130	110	-15%
Year 2	494	436	-12%	59,622	48,029	-19%	121	110	-9%
Year 3	587	568	-3%	68,784	63,599	-8%	117	112	-4%
Year 4	638	619	-3%	73,054	67,869	-7%	115	110	-4%
Year 5	715	696	-3%	87,574	82,389	-6%	122	118	-3%
Years 1-5 Total	**715**	**696**	**-3%**	**335,002**	**309,870**	**-8%**	**122**	**118**	**-3%**

Table 8-3: 2011 FEI Aggregate Main Extensions Profitability Index

2011 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1			
Year 2			
Year 3	1.39	1.05	-25%
Year 4			
Year 5			
Years 1-5 Total	**1.39**	**1.05**	**-25%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed to the Commission[10].
- The variance between the year 1 forecast and year 1 actual costs is attributable to a combination of variance in costs and attachments.
- 7 FEI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

8.2 *2011 FEVI SAMPLE RESULTS*

The tables below summarize the sample aggregate 2011 main extension results for FEVI.

[10] FEI & FEVI Main Extension Report for 2011 Year End, submitted to the Commission July 31, 2012.

Table 8-4: 2011 FEVI Aggregate Main Extensions Costs

2011 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEVI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 513,670	$ 557,216	8%
	Service lines and meters	$ 196,013	$ 217,412	11%
	Year 1 Total	$ 709,683	$ 774,628	9%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 93,849	$ 41,132	-56%
	Year 2 Total	$ 93,849	$ 41,132	-56%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 41,579	$ 55,822	34%
	Year 3 Total	$ 41,579	$ 55,822	34%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 7,128	$ -	-100%
	Year 4 Total	$ 7,128	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 7,128	$ -	-100%
	Year 5 Total	$ 7,128	$ -	-100%
Years 1-5 Total		**$859,365**	**$871,582**	**1%**

Table 8-5: 2011 FEVI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2011 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
	Attachments			Consumption (GJ)			Use per Customer		
FEVI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	165	148	-10%	15,038	19,461	29%	91	131	44%
Year 2	244	176	-28%	18,246	20,013	10%	75	114	52%
Year 3	279	214	-23%	19,495	20,977	8%	70	98	40%
Year 4	285	220	-23%	19,709	21,191	8%	69	96	39%
Year 5	291	226	-22%	19,958	21,440	7%	69	95	38%
Years 1-5 Total	**291**	**226**	**-22%**	**92,446**	**103,082**	**12%**	**69**	**95**	**38%**

Table 8-6: 2011 FEVI Aggregate Main Extensions Profitability Index

2011 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.33	1.44	8%
Years 1-5 Total	**1.33**	**1.44**	**8%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[11].
- The variance between the year 1 forecast and year 1 actual costs is attributable to a combination of variance in costs and attachments.
- 7 FEVI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

8.3 *2011 FEI TOP 5 RESULTS*

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 8-1 & 8-2	Table 8-3 & 8-4	Table 8-5 & 8-6	Table 8-7 & 8-8	Table 8-9 & 8-10	Table 8-11
96 Avenue	Harper Road	Townshipline Road	Sammet Road	1st Avenue	Top 5 P.I. Results

Table 8-7: 2011 FEI Top 5 – 96th Avenue Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550003882	96 Ave	Original Forecast	Actual	Variance %
Year 1	Mains	$ 69,593	$ 74,954	8%
	Service lines and meters	$ 1,176	$ 3,120	165%
	Year 1 Total	$ 70,769	$ 78,074	10%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 1,176	$ -	-100%
	Year 2 Total	$ 1,176	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$71,946**	**$78,074**	**9%**

[11] FEI & FEVI Main Extension Report for 2011 Year End, submitted to the Commission July 31, 2012.

Table 8-8: 2011 FEI Top 5 – 96th Avenue Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
96 Ave 5550003882	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	1	2	100%	11,271	6,915	-39%	11,271	3,457	-69%	
Year 2	2	2	0%	22,454	6,915	-69%	11,227	3,457	-69%	
Year 3	2	2	0%	22,454	6,915	-69%	11,227	3,457	-69%	0%
Year 4	2	2	0%	22,454	6,915	-69%	11,227	3,457	-69%	
Year 5	2	2	0%	22,454	6,915	-69%	11,227	3,457	-69%	
Years 1-5 Total	**2**	**2**	**0%**	**101,087**	**34,574**	**-66%**	**11,227**	**3,457**	**-69%**	

Table 8-9: 2011 FEI Top 5 – Harper Road Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550002684	Harper Rd	Original Forecast	Actual	Variance %
Year 1	Mains	$ 98,437	$ 73,832	-25%
	Service lines and meters	$ 27,057	$ 82,669	206%
	Year 1 Total	$ 125,494	$ 156,500	25%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 27,057	$ 88,908	229%
	Year 2 Total	$ 27,057	$ 88,908	229%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 27,057	$ 4,679	-83%
	Year 3 Total	$ 27,057	$ 4,679	-83%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 27,057	$ -	-100%
	Year 4 Total	$ 27,057	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 27,057	$ -	-100%
	Year 5 Total	$ 27,057	$ -	-100%
Years 1-5 Total		**$233,723**	**$250,088**	**7%**

Table 8-10: 2011 FEI Top 5 – Harper Road Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Harper Rd 5550002684	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	23	53	130%	2,292	2,934	28%	100	55	-44%	
Year 2	46	110	139%	4,584	6,158	34%	100	56	-44%	
Year 3	69	113	64%	6,876	6,307	-8%	100	56	-44%	0%
Year 4	92	136	48%	9,168	8,599	-6%	100	63	-37%	
Year 5	115	159	38%	11,460	10,891	-5%	100	68	-31%	
Years 1-5 Total	**115**	**159**	**38%**	**34,380**	**34,889**	**1%**	**100**	**68**	**-31%**	

Table 8-10: 2011 FEI Top 5 – Townshipline Road Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550004429	Townshipline Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 27,222	$ 48,855	79%
	Service lines and meters	$ 1,176	$ 1,560	33%
	Year 1 Total	$ 28,399	$ 50,415	78%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$28,399	$50,415	78%

Table 8-11: 2011 FEI Top 5 – Townshipline Road Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Townshipline Road 5550004429	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	1	1	0%	576	11,180	1841%	576	11,180	1841%	
Year 2	1	1	0%	576	11,180	1841%	576	11,180	1841%	
Year 3	1	1	0%	576	11,180	1841%	576	11,180	1841%	0%
Year 4	1	1	0%	576	11,180	1841%	576	11,180	1841%	
Year 5	1	1	0%	576	11,180	1841%	576	11,180	1841%	
Years 1-5 Total	1	1	0%	2,880	55,901	1841%	576	11,180	1841%	

Notes:

- Customer is classified as a Rate 3 (Greenhouse) with consumption levels reflecting an expansion of original project requirements.

Table 8-12: 2011 FEI Top 5 – Sammet Road Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550003356	Sammet Rd	Original Forecast	Actual	Variance %
Year 1	Mains	$ 59,469	$ 23,830	-60%
	Service lines and meters	$ 2,353	$ 4,679	99%
	Year 1 Total	$ 61,822	$ 28,510	-54%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$61,822**	**$28,510**	**-54%**

Table 8-13: 2011 FEI Top 5 – Sammet Road Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Sammet Rd 5550003356	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	2	3	50%	610	1,106	81%	305	369	21%	
Year 2	2	3	50%	610	1,106	81%	305	369	21%	
Year 3	2	3	50%	610	1,106	81%	305	369	21%	0%
Year 4	2	3	50%	610	1,106	81%	305	369	21%	
Year 5	2	3	50%	610	1,106	81%	305	369	21%	
Years 1-5 Total	**2**	**3**	**50%**	**3,050**	**5,529**	**81%**	**305**	**369**	**21%**	

Notes:

- The actual costs for this project are reduced by a CIAC of approximately $57,000.
- There were cost over-runs due to traffic management (on highway) and a difficult running line to avoid a newly paved secondary highway. These additional costs are reflected in the actual PI result found in Table 53.

Table 8-14: 2011 FEI Top 5 – 1st Avenue Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550003968	1st Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 38,704	$ 14,623	-62%
	Service lines and meters	$ 2,353	$ 3,120	33%
	Year 1 Total	$ 41,057	$ 17,742	-57%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$41,057**	**$17,742**	**-57%**

Table 8-15: 2011 FEI Top 5 – 1st Avenue Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
1st Avenue 5550003968	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	2	2	0%	245	222	-9%	123	111	-9%	
Year 2	2	2	0%	245	222	-9%	123	111	-9%	
Year 3	2	2	0%	245	222	-9%	123	111	-9%	0%
Year 4	2	2	0%	245	222	-9%	123	111	-9%	
Year 5	2	2	0%	245	222	-9%	123	111	-9%	
Years 1-5 Total	**2**	**2**	**0%**	**1,225**	**1,112**	**-9%**	**123**	**111**	**-9%**	

Notes:

- The actual costs for this project are reduced by a CIAC of approximately $42,000.
- There were cost over-runs due to impediments around a directional drill underneath three existing CP railway lines. These additional costs are reflected in the actual PI result found in Table 53.

Table 8-16: 2011 FEI Top 5 Main Extensions Profitability Index

2011 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
96 Ave	4.18	1.39	-67%
Harper Rd	1.15	0.84	-27%
Townshipline Road	0.83	3.16	280%
Sammet Rd	0.80	0.76	-6%
1st Avenue	0.80	0.23	-71%
Years 1-5 Total	**1.55**	**1.27**	**-18%**

8.1 *2011 FEVI TOP 5 RESULTS*

The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 8-17 & 8-18	Table 8-19 & 8-20	Table 8-21 & 8-22	Table 8-23 & 8-24	Table 8-25 & 8-26	Table 8-27
Englewood Road	Mountain Heights Road	Sooke Road	Veteran's Memorial Parkway	Latoria Road	Top 5 P.I. Results

Table 8-17: 2011 FEVI Top 5 – Englewood Road Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550004644	Englewood Rd	Original Forecast	Actual	Variance %
Year 1	Mains	$ 53,758	$ 101,509	89%
	Service lines and meters	$ 19,007	$ 33,787	78%
	Year 1 Total	$ 72,765	$ 135,296	86%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 10,692	$ 30,849	189%
	Year 2 Total	$ 10,692	$ 30,849	189%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 8,316	$ 8,814	6%
	Year 3 Total	$ 8,316	$ 8,814	6%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 4,752	$ -	-100%
	Year 4 Total	$ 4,752	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 4,752	$ -	-100%
	Year 5 Total	$ 4,752	$ -	-100%
Years 1-5 Total		**$101,276**	**$174,959**	**73%**

Table 8-18: 2011 FEVI Top 5 – Englewood Road Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Englewood Rd 5550004644	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	16	23	44%	634	329	-48%	40	14	-64%	80%
Year 2	25	44	76%	991	602	-39%	40	14	-65%	
Year 3	32	50	56%	1,269	710	-44%	40	14	-64%	
Year 4	36	54	50%	1,428	869	-39%	40	16	-59%	
Year 5	40	58	45%	1,587	1,028	-35%	40	18	-55%	
Years 1-5 Total	**40**	**58**	**45%**	**5,909**	**3,539**	**-40%**	**40**	**18**	**-55%**	

Notes:

- Construction costs are higher due to a difficult job site, including additional costs for paving.
- The gas load estimate included installation of a hot water tank, fireplace and BBQ. The consumption projection anticipated a higher uptake on hot water tanks per home than actual. The market showed that entry level customers were seeking a lowest cost option.
- Several lots that have been developed have not been sold and exhibit consumption reflective of appliance testing and construction heat only.

Table 8-19: 2011 FEVI Top 5 – Mountain Heights Road Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550003319	Mountain Heights Rd	Original Forecast	Actual	Variance %
Year 1	Mains	$ 88,037	$ 99,102	13%
	Service lines and meters	$ 47,518	$ 14,690	-69%
	Year 1 Total	$ 135,556	$ 113,792	-16%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 35,639	$ -	-100%
	Year 2 Total	$ 35,639	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 23,759	$ 10,283	-57%
	Year 3 Total	$ 23,759	$ 10,283	-57%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$194,953**	**$124,075**	**-36%**

Table 8-20: 2011 FEVI Top 5 – Mountain Heights Road Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Mountain Heights Rd 5550003319	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	40	10	-75%	3,370	183	-95%	84	18	-78%	0%
Year 2	70	10	-86%	5,898	183	-97%	84	18	-78%	
Year 3	90	17	-81%	7,583	312	-96%	84	18	-78%	
Year 4	90	17	-81%	7,583	312	-96%	84	18	-78%	
Year 5	90	17	-81%	7,583	312	-96%	84	18	-78%	
Years 1-5 Total	**90**	**17**	**-81%**	**32,017**	**1,302**	**-96%**	**84**	**18**	**-78%**	

Notes:

- The developer of this subdivision sold individual lots to builders with the majority of lots in the development still vacant or at the early stages of construction.
- Those lots that have been developed have not been sold and exhibit consumption reflective of appliance testing and construction heat only.
- The Companies are currently tracking building permits and will engage builders in discussions regarding energy solutions.

Table 8-21: 2011 FEVI Top 5 – Sooke Road Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550004292	Sooke Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 136,725	$ 68,387	-50%
	Service lines and meters	$ 59,398	$ -	-100%
	Year 1 Total	$ 196,123	$ 68,387	-65%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 59,398	$ 73,450	24%
	Year 2 Total	$ 59,398	$ 73,450	24%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$255,521**	**$141,837**	**-44%**

Table 8-22: 2011 FEVI Top 5 – Sooke Road Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Sooke Road 5550004292	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	50	0	-100%	2,174	0	-100%	43			
Year 2	100	50	-50%	4,593	898	-80%	46	18	-61%	
Year 3	100	50	-50%	4,593	898	-80%	46	18	-61%	0%
Year 4	100	50	-50%	4,593	898	-80%	46	18	-61%	
Year 5	100	50	-50%	4,593	898	-80%	46	18	-61%	
Years 1-5 Total	**100**	**50**	**-50%**	**20,546**	**3,591**	**-83%**	**46**	**18**	**-61%**	

Notes:

- Several large vertical subdivision buildings that were originally part of the project costs and were put on hold due to construction complications have recently been completed. The associated attachments, approximately 40 to 60 to date, will appear in future MX Reports.

Table 8-23: 2011 FEVI Top 5 – Veterans Memorial Parkway Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
5550002742	FEVI Veteran's Memorial Parkway	Cost of Installation ($)		
		Original Forecast	Actual	Variance %
Year 1	Mains	$ 54,615	$ 68,023	25%
	Service lines and meters	$ 13,068	$ 17,628	35%
	Year 1 Total	$ 67,683	$ 85,651	27%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 11,880	$ -	-100%
	Year 2 Total	$ 11,880	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 13,068	$ 4,407	-66%
	Year 3 Total	$ 13,068	$ 4,407	-66%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 13,068	$ -	-100%
	Year 4 Total	$ 13,068	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 1,188	$ -	-100%
	Year 5 Total	$ 1,188	$ -	-100%
Years 1-5 Total		**$106,885**	**$90,058**	**-16%**

Table 8-24: 2011 FEVI Top 5 – Veterans Memorial Parkway Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Veteran's Memorial Parkway 5550002742	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	11	12	9%	694	65	-91%	63	5	-91%	
Year 2	21	12	-43%	1,457	65	-96%	69	5	-92%	
Year 3	32	15	-53%	1,964	104	-95%	61	7	-89%	45%
Year 4	43	26	-40%	2,471	611	-75%	57	23	-59%	
Year 5	44	27	-39%	2,536	676	-73%	58	25	-57%	
Years 1-5 Total	**44**	**27**	**-39%**	**9,122**	**1,521**	**-83%**	**58**	**25**	**-57%**	

Notes:

- Developer has taken a significant amount of time to register lots. Installation had to take place at an early stage of project as main alignment was projected to be under new asphalt. Lots have been registered for only 4 months and 2 lots have been sold to date. The developer expects sales to take off after provincial HST issue is resolved. The Companies are in contact with the developer to discuss marketing strategy.

Table 8-25: 2011 FEVI Top 5 – Latoria Road Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550004579	Latoria Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 27,200	$ 55,572	104%
	Service lines and meters	$ 16,631	$ 24,973	50%
	Year 1 Total	$ 43,831	$ 80,545	84%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 8,316	$ -	-100%
	Year 2 Total	$ 8,316	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 8,316	$ 5,876	-29%
	Year 3 Total	$ 8,316	$ 5,876	-29%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	

Table 8-26: 2011 FEVI Top 5 – Latoria Road Attachments, Consumption and Use per Customer

2011 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Latoria Road 5550004579	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	14	17	21%	383	471	23%	27	28	1%	
Year 2	21	17	-19%	575	471	-18%	27	28	1%	
Year 3	28	21	-25%	767	600	-22%	27	29	4%	80%
Year 4	28	21	-25%	767	600	-22%	27	29	4%	
Year 5	28	21	-25%	767	600	-22%	27	29	4%	
Years 1-5 Total	**28**	**21**	**-25%**	**3,259**	**2,743**	**-16%**	**27**	**29**	**4%**	

Notes:

- Actual costs are higher due to a conflict with fire hydrants and a water main.

Table 8-27: 2011 FEVI Top 5 Main Extensions Profitability Index

2011 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Englewood Rd	0.95	0.34	-64%
Mountain Heights Rd	1.29	0.05	-96%
Sooke Road	1.45	0.68	-53%
Veteran's Memorial Parkway	1.52	0.36	-76%
Latoria Road	0.87	0.42	-52%
Years 1-5 Total	**1.22**	**0.37**	**-70%**

9. 2010 MAIN EXTENSIONS

The following section summarizes the attachment and consumption results for the 2010 main extensions including vertical subdivisions.

- The forecasted results contained in this section are based on projects for the 2010 gas year (November 01, 2009 to October 31, 2010).
- The actual results in this section are from November 01, 2009 to October 31, 2012.
- The tables included in this section contain a comparison of forecasted and actual costs, attachments and consumption for Year 3.
- For the projects included in the Top 5 section, the Companies have provided explanations where unique circumstances exist. For those projects that do not include explanations, variances are a result of labour or material cost differences or the challenges in accurately forecasting attachments and consumption.
- The grey shading in the tables is used to indicate a forecast year.

9.1 *2010 FEI SAMPLE RESULTS*

The tables below summarize the sample aggregate 2010 main extension results for FEI.

Table 9-1: 2010 FEI Aggregate Main Extensions Costs

2010 SAMPLE MAIN EXTENSIONS - COSTS				
FEI	Cost of Installation ($)			
		Original Forecast	Actual	Variance %
Year 1	Mains	$ 458,129	$ 453,092	-1%
	Service lines and meters	$ 234,992	$ 322,793	37%
	Year 1 Total	$ 693,121	$ 775,885	12%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 93,463	$ 164,109	76%
	Year 2 Total	$ 93,463	$ 164,109	76%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 51,627	$ 35,263	-32%
	Year 3 Total	$ 51,627	$ 35,263	-32%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 25,814	$ 47,470	84%
	Year 4 Total	$ 25,814	$ 47,470	84%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 19,583	$ -	-100%
	Year 5 Total	$ 19,583	$ -	-100%
Years 1-5 Total		**$883,607**	**$1,022,727**	**16%**

Table 9-2: 2010 FEI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2010 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
FEI	Attachments			Consumption (GJ)			Use per Customer		
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	264	238	-10%	39,692	10,387	-74%	150	44	-71%
Year 2	369	359	-3%	50,019	15,922	-68%	136	44	-67%
Year 3	427	385	-10%	55,967	16,945	-70%	131	44	-66%
Year 4	456	420	-8%	58,932	18,265	-69%	129	43	-66%
Year 5	478	442	-8%	61,244	20,577	-66%	128	47	-64%
Years 1-5 Total	**478**	**442**	**-8%**	**265,854**	**82,096**	**-69%**	**128**	**47**	**-64%**

Table 9-3: 2010 FEI Aggregate Main Extensions Profitability Index

2010 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.69	0.53	-69%
Years 1-5 Total	**1.69**	**0.53**	**-69%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed to the Commission[12].
- The variance between the Year 1-2 forecast and Year 1-2 actual costs is attributable to a combination of variance in costs and attachments.
- 2 FEI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

9.2 *2010 FEVI SAMPLE RESULTS*

The tables below summarize the sample aggregate 2010 main extension results for FEVI.

[12] Addendum to Main Extension Report and FortisBC Energy Inc. Vertical Subdivision Report for 2010 Year End, submitted to the Commission October 14, 2011.

Table 9-4: 2010 FEVI Aggregate Main Extensions Costs

2010 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEVI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 467,152	$ 482,629	3%
	Service lines and meters	$ 267,481	$ 166,668	-38%
	Year 1 Total	$ 734,634	$ 649,297	-12%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 78,353	$ 103,360	32%
	Year 2 Total	$ 78,353	$ 103,360	32%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 9,006	$ 32,300	259%
	Year 3 Total	$ 9,006	$ 32,300	259%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 7,205	$ 36,176	402%
	Year 4 Total	$ 7,205	$ 36,176	402%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$829,198**	**$821,133**	**-1%**

Table 9-5: 2010 FEVI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2010 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
	Attachments			Consumption (GJ)			Use per Customer		
FEVI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	297	129	-57%	20,565	4,778	-77%	69	37	-47%
Year 2	384	209	-46%	24,547	5,467	-78%	64	26	-59%
Year 3	394	234	-41%	24,899	5,702	-77%	63	24	-61%
Year 4	402	262	-35%	25,143	5,905	-77%	63	23	-64%
Year 5	402	262	-35%	25,143	5,905	-77%	63	23	-64%
Years 1-5 Total	**402**	**262**	**-35%**	**120,297**	**27,757**	**-77%**	**63**	**23**	**-64%**

Table 9-6: 2010 FEVI Aggregate Main Extensions Profitability Index

2010 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.48	0.47	-68%
Years 1-5 Total	**1.48**	**0.47**	**-68%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed to the Commission[13].
- The variance between the Year 1-2 forecast and Year 1-2 actual costs is attributable to a combination of variance in costs and attachments.
- 7 FEVI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

9.3 *2010 FEI TOP 5 RESULTS*

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 9-7 & 9-8	Table 9-9 & 9-10	Table 9-11 & 9-12	Table 9-13 & 9-14	Table 9-15 & 9-16	Table 9-17
Whiskey Jack Drive	Gislason Avenue	Progress Way	Highway 95A	Pinot Noir Drive	Top 5 P.I. Results

Table 9-7: 2010 FEI Top 5 – Whiskey Jack Drive Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550002814	Whiskey Jack Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 110,429	$ 161,457	46%
	Service lines and meters	$ 26,704	$ 36,619	37%
	Year 1 Total	$ 137,132	$ 198,077	44%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 17,802	$ 17,632	-1%
	Year 2 Total	$ 17,802	$ 17,632	-1%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 4,451	$ 1,356	-70%
	Year 3 Total	$ 4,451	$ 1,356	-70%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 4,451	$ 17,632	296%
	Year 4 Total	$ 4,451	$ 17,632	296%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 4,451	$ -	-100%
	Year 5 Total	$ 4,451	$ -	-100%
Years 1-5 Total		**$168,286**	**$234,696**	**39%**

[13] Addendum to Main Extension Report and FortisBC Energy Inc. Vertical Subdivision Report for 2010 Year End, submitted to the Commission October 14, 2011.

Table 9-8: 2010 FEI Top 5 – Whiskey Jack Drive Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Whiskey Jack Drive 5550002814	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	30	27	-10%	3,022	773	-74%	101	29	-72%	0%
Year 2	50	40	-20%	5,036	1,123	-78%	101	28	-72%	
Year 3	55	41	-25%	5,540	1,206	-78%	101	29	-71%	
Year 4	60	54	-10%	6,044	1,623	-73%	101	30	-70%	
Year 5	65	59	-9%	6,548	2,127	-68%	101	36	-64%	
Years 1-5 Total	**65**	**59**	**-9%**	**26,190**	**6,852**	**-74%**	**101**	**36**	**-64%**	

Notes:

- This project incurred extra costs for compaction, road repair and construction materials.
- The geo-priced cost forecasting was performed prior to the Companies implementing an enhancement for projects using large diameter pipe. As a result, the forecast costs were underestimated.

Table 9-9: 2010 FEI Top 5 – Gislason Avenue Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550001486	Gislason Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 144,616	$ 127,886	-12%
	Service lines and meters	$ 17,802	$ 99,008	456%
	Year 1 Total	$ 162,418	$ 226,894	40%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 17,802	$ 1,356	-92%
	Year 2 Total	$ 17,802	$ 1,356	-92%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 17,802	$ 2,713	-85%
	Year 3 Total	$ 17,802	$ 2,713	-85%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 17,802	$ -	-100%
	Year 4 Total	$ 17,802	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 17,802	$ -	-100%
	Year 5 Total	$ 17,802	$ -	-100%
Years 1-5 Total		**$233,628**	**$230,963**	**-1%**

Table 9-10: 2010 FEI Top 5 – Gislason Avenue Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Gislason Avenue 5550001486	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	20	73	265%	2,163	3,804	76%	108	52	-52%	0%
Year 2	40	74	85%	4,326	3,857	-11%	108	52	-52%	
Year 3	60	76	27%	6,489	3,913	-40%	108	51	-52%	
Year 4	80	76	-5%	8,652	3,913	-55%	108	51	-52%	
Year 5	100	96	-4%	10,815	6,076	-44%	108	63	-41%	
Years 1-5 Total	**100**	**96**	**-4%**	**32,445**	**21,563**	**-34%**	**108**	**63**	**-41%**	

Table 9-11: 2010 FEI Top 5 – Progress Way Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550000039	Progress Way	Original Forecast	Actual	Variance %
Year 1	Mains	$ 118,642	$ 81,035	-32%
	Service lines and meters	$ 2,670	$ 4,069	52%
	Year 1 Total	$ 121,313	$ 85,104	-30%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 10,681	$ -	-100%
	Year 2 Total	$ 10,681	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 3,560	$ -	-100%
	Year 3 Total	$ 3,560	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 890	$ 1,356	52%
	Year 4 Total	$ 890	$ 1,356	52%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 3,560	$ -	-100%
	Year 5 Total	$ 3,560	$ -	-100%
Years 1-5 Total		**$140,005**	**$86,460**	**-38%**

Table 9-12: 2010 FEI Top 5 – Progress Way Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Progress Way 5550000039	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	3	3	0%	1,912	590	-69%	637	197	-69%	0%
Year 2	15	3	-80%	4,629	590	-87%	309	197	-36%	
Year 3	19	3	-84%	7,178	590	-92%	378	197	-48%	
Year 4	20	4	-80%	8,098	914	-89%	405	229	-44%	
Year 5	24	8	-67%	11,543	4,359	-62%	481	545	13%	
Years 1-5 Total	**24**	**8**	**-67%**	**33,360**	**7,043**	**-79%**	**481**	**545**	**13%**	

Notes:

- The economic downturn is the main reason cited by the developer as to why there has been little attachment activity. However, all lots are now cleared with construction activity picking up.

Table 9-13: 2010 FEI Top 5 – Highway 95A Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550004126	Highway 95A	Original Forecast	Actual	Variance %
Year 1	Mains	$ 63,050	$ 72,910	16%
	Service lines and meters	$ 13,352	$ 1,356	-90%
	Year 1 Total	$ 76,402	$ 74,266	-3%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 8,901	$ 4,069	-54%
	Year 2 Total	$ 8,901	$ 4,069	-54%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 8,901	$ -	-100%
	Year 3 Total	$ 8,901	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 8,901	$ -	-100%
	Year 4 Total	$ 8,901	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$103,105**	**$78,335**	**-24%**

Table 9-14: 2010 FEI Top 5 – Highway 95A Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Highway 95A 5550004126	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	15	1	-93%	1,511	60	-96%	101	60	-40%	
Year 2	25	4	-84%	2,518	260	-90%	101	65	-35%	
Year 3	35	4	-89%	3,525	260	-93%	101	65	-35%	0%
Year 4	45	4	-91%	4,532	260	-94%	101	65	-35%	
Year 5	45	4	-91%	4,532	260	-94%	101	65	-35%	
Years 1-5 Total	**45**	**4**	**-91%**	**16,618**	**1,100**	**-93%**	**101**	**65**	**-35%**	

Notes:

- Market conditions deteriorated after the project was completed with all utilities installed including natural gas.
- The project is currently being actively marketed with attachments likely deferred for economic reasons. This project is owned by Shadow Mountain Resorts and was intended to attract customers from Alberta looking for luxury resort accommodations as such; the attachment potential is highly contingent upon economic recovery.

Table 9-15: 2010 FEI Top 5 – Pinot Noir Drive Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS		Cost of Installation ($)		
FEI 4110027393	Pinot Noir Dr	Original Forecast	Actual	Variance %
Year 1	Mains	$ 84,220	$ 46,420	-45%
	Service lines and meters	$ -	$ 24,413	
	Year 1 Total	$ 84,220	$ 70,833	-16%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 21,363	$ 9,494	-56%
	Year 2 Total	$ 21,363	$ 9,494	-56%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 21,363	$ 1,356	-94%
	Year 3 Total	$ 21,363	$ 1,356	-94%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 12,462	$ 12,206	-2%
	Year 4 Total	$ 12,462	$ 12,206	-2%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$139,408**	**$93,890**	**-33%**

Table 9-16: 2010 FEI Top 5 – Pinot Noir Drive Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER	Attachments			Consumption (GJ)			Use per Customer			
FEI Pinot Noir Dr 4110027393	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	0	18	-	0	966	-	0	54	-	0%
Year 2	24	25	4%	2,417	1,424	-41%	101	57	-43%	
Year 3	48	26	-46%	4,834	1,488	-69%	101	57	-43%	
Year 4	62	35	-44%	6,244	1,861	-70%	101	53	-47%	
Year 5	62	35	-44%	6,244	1,861	-70%	101	53	-47%	
Years 1-5 Total	**62**	**35**	**-44%**	**19,739**	**7,602**	**-61%**	**101**	**53**	**-47%**	

Notes:

- The costs for this project have been reduced by a CIAC of approximately $18,000.

Table 9-17: 2010 FEI Top 5 Main Extensions Profitability Index

2010 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Whiskey Jack Drive	0.78	0.18	-77%
Gislason Avenue	0.96	0.57	-41%
Progress Way	1.05	0.61	-42%
Highway 95A	0.93	0.00	-100%
Pinot Noir Dr	0.84	0.47	-44%
Years 1-5 Total	**0.91**	**0.36**	**-60%**

9.4 *2010 FEVI TOP 5 RESULTS*

The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 9-18 & 9-19	Table 9-20 & 9-21	Table 9-22 & 9-23	Table 9-24 & 9-25	Table 9-26 & 9-27	Table 9-28
Riverstone Drive	Norton Road	Chilco Road	Fifth Street	Rosstown Road	Top 5 P.I. Results

Table 9-18: 2010 FEVI Top 5 – Riverstone Road Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550001060	Riverstone Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 75,139	$ 108,523	44%
	Service lines and meters	$ 40,527	$ 34,884	-14%
	Year 1 Total	$ 115,667	$ 143,407	24%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 10,336	
	Year 4 Total	$ -	$ 10,336	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$115,667**	**$153,743**	**33%**

Table 9-19: 2010 FEVI Top 5 – Riverstone Road Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Riverstone Drive 5550001060	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	45	27	-40%	3,150	296	-91%	70	11	-84%	
Year 2	45	27	-40%	3,150	296	-91%	70	11	-84%	
Year 3	45	27	-40%	3,150	296	-91%	70	11	-84%	0%
Year 4	45	35	-22%	3,150	322	-90%	70	9	-87%	
Year 5	45	35	-22%	3,150	322	-90%	70	9	-87%	
Years 1-5 Total	**45**	**35**	**-22%**	**15,750**	**1,532**	**-90%**	**70**	**9**	**-87%**	

Notes:

- This project was Geo-Priced before manual estimating rules for larger mains came into place. As such the cost per meter was not representative due to rocky ground and higher pressure requirements.

Table 9-20: 2010 FEVI Top 5 – Norton Road Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
4110027102	Norton Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 47,346	$ 64,952	37%
	Service lines and meters	$ 13,509	$ 32,300	139%
	Year 1 Total	$ 60,855	$ 97,252	60%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 13,509	$ 3,876	-71%
	Year 2 Total	$ 13,509	$ 3,876	-71%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 13,509	$ 5,168	-62%
	Year 3 Total	$ 13,509	$ 5,168	-62%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 7,752	
	Year 4 Total	$ -	$ 7,752	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$87,874**	**$114,048**	**30%**

Table 9-21: 2010 FEVI Top 5 – Norton Road Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Norton Road 4110027102	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	15	25	67%	1,050	259	-75%	70	10	-85%	
Year 2	30	28	-7%	2,100	300	-86%	70	11	-85%	
Year 3	45	32	-29%	3,150	461	-85%	70	14	-79%	0%
Year 4	45	38	-16%	3,150	635	-80%	70	17	-76%	
Year 5	45	38	-16%	3,150	635	-80%	70	17	-76%	
Years 1-5 Total	**45**	**38**	**-16%**	**12,600**	**2,290**	**-82%**	**70**	**17**	**-76%**	

Table 9-22: 2010 FEVI Top 5 – Chilco Road Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550001973	Chilco Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 80,573	$ 90,789	13%
	Service lines and meters	$ 19,813	$ 7,752	-61%
	Year 1 Total	$ 100,387	$ 98,541	-2%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 19,813	$ 37,468	89%
	Year 2 Total	$ 19,813	$ 37,468	89%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 18,913	$ 2,584	-86%
	Year 3 Total	$ 18,913	$ 2,584	-86%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 36,176	
	Year 4 Total	$ -	$ 36,176	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$139,113**	**$174,769**	**26%**

Table 9-23: 2010 FEVI Top 5 – Chilco Road Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Chilco Road 5550001973	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	22	6	-73%	1,060	54	-95%	48	9	-81%	
Year 2	44	35	-20%	2,017	244	-88%	46	7	-85%	
Year 3	65	37	-43%	2,878	270	-91%	44	7	-84%	0%
Year 4	65	65	0%	2,878	451	-84%	44	7	-84%	
Year 5	65	65	0%	2,878	451	-84%	44	7	-84%	
Years 1-5 Total	**65**	**65**	**0%**	**11,711**	**1,470**	**-87%**	**44**	**7**	**-84%**	

Notes:

- $38,000 in additional mains costs have been added due to the completion of the final phase of the main install which was on hold since 2010.

Table 9-24: 2010 FEVI Top 5 – Fifth Street Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550001073	Fifth Street	Original Forecast	Actual	Variance %
Year 1	Mains	$ 16,230	$ 38,840	139%
	Service lines and meters	$ 16,211	$ 25,840	59%
	Year 1 Total	$ 32,441	$ 64,680	99%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 1,292	
	Year 2 Total	$ -	$ 1,292	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 3 Total	$ -	$ -	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$32,441	$65,972	103%

Table 9-25: 2010 FEVI Top 5 – Fifth Street Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Fifth Street 5550001073	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	18	20	11%	9,914	1,626	-84%	551	81	-85%	0%
Year 2	18	21	17%	9,914	2,615	-74%	551	125	-77%	
Year 3	18	21	17%	9,914	2,615	-74%	551	125	-77%	
Year 4	18	21	17%	9,914	2,615	-74%	551	125	-77%	
Year 5	18	21	17%	9,914	2,615	-74%	551	125	-77%	
Years 1-5 Total	18	21	17%	49,570	12,086	-76%	551	125	-77%	

Notes:

- This project was a conversion of an older mall to plaza type shopping facility.
- Additional costs were incurred for the unplanned removal of old steel mains and existing below grade service lines that were no longer required. Actual costs are also higher due to asphalt and sidewalk cuts and repairs related to new service lines.

Table 9-26: 2010 FEVI Top 5 – Rosstown Road Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550003357	Rosstown Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 19,464	$ 37,675	94%
	Service lines and meters	$ 2,702	$ 3,876	43%
	Year 1 Total	$ 22,166	$ 41,551	87%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 2,702	$ -	-100%
	Year 2 Total	$ 2,702	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 901	$ -	-100%
	Year 3 Total	$ 901	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 901	$ -	-100%
	Year 4 Total	$ 901	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$26,669**	**$41,551**	**56%**

Table 9-27: 2010 FEVI Top 5 – Rosstown Road Attachments, Consumption and Use per Customer

2010 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Rosstown Road 5550003357	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	3	3	0%	221	33	-85%	74	11	-85%	
Year 2	6	3	-50%	549	33	-94%	92	11	-88%	
Year 3	7	3	-57%	609	33	-95%	87	11	-87%	0%
Year 4	8	3	-63%	628	33	-95%	79	11	-86%	
Year 5	8	3	-63%	628	33	-95%	79	11	-86%	
Years 1-5 Total	**8**	**3**	**-63%**	**2,635**	**165**	**-94%**	**79**	**11**	**-86%**	

Notes:

- This project incurred additional costs due to last minute changes in hydro location. As a result the main location had to be moved in accordance with industry standards. Additional backfill material and compaction charges were also incurred.
- Poor market conditions have impacted the number of attachments on this main. Attachment potential still exists and the Companies will continue to monitor & canvas for opportunities.

1 **Table 9-28: 2010 FEVI Top 5 Main Extensions Profitability Index**

2010 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Riverstone Drive	1.15	0.08	-93%
Norton Road	1.38	0.25	-82%
Chilco Road	1.17	0.31	-73%
Fifth Street	17.38	2.93	-83%
Rosstown Road	0.81	0.00	-100%
Years 1-5 Total	**4.38**	**0.71**	**-84%**

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10. 2009 MAIN EXTENSIONS

The following section summarizes the attachment and consumption results for the 2008 main extensions including vertical subdivisions.

- The forecasted results contained in this section are based on projects for the 2008 gas year (November 01, 2007 to October 31, 2008).
- The actual results in this section are from November 01, 2007 to October 31, 2012.
- The tables included in this section contain a comparison of forecasted and actual costs, attachments and consumption for Year 5.
- For the projects included in the Top 5 section, the Companies have provided explanations where unique circumstances exist. For those projects that do not include explanations, variances are a result of labour or material cost differences or the challenges in accurately forecasting attachments and consumption.

The 2013 MX Report will be the final year of reporting on the 2008 cohort of mains. Removing the 2008 mains from future MX Reporting is simply a result of the previously agreed upon main extension reporting construct and does not indicate that the Companies are in a position to assess the final measures of attachments or consumption.

The data tables contained in this section are based on a small sample of the actual main installations in 2008 and are not representative of the final impact of the mains on new or existing customers. In addition, the results up to this point in time, only consider attachments in the first 5 years of the life of the mains, as such, the attachment figures do not account for any activity after October 31, 2012. The Companies fully expect continued attachment and consumption growth to materialize on these mains throughout the full life of the asset.

10.1 *2009 FEI SAMPLE RESULTS*

The tables below summarize the sample aggregate 2009 main extension results for FEI.

Table 10-1: 2009 FEI Aggregate Main Extensions Costs

2009 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 873,525	$ 944,648	8%
	Service lines and meters	$ 616,783	$ 699,124	13%
	Year 1 Total	$ 1,490,308	$ 1,643,772	10%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 217,513	$ 419,767	93%
	Year 2 Total	$ 217,513	$ 419,767	93%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 174,805	$ 270,581	55%
	Year 3 Total	$ 174,805	$ 270,581	55%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 120,178	$ 80,443	-33%
	Year 4 Total	$ 120,178	$ 80,443	-33%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 90,382	$ 81,906	-9%
	Year 5 Total	$ 90,382	$ 81,906	-9%
Years 1-5 Total		**$2,093,186**	**$2,496,469**	**19%**

Table 10-2: 2009 FEI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2009 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
	Attachments			Consumption (GJ)			Use per Customer		
FEI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	621	478	-23%	75,052	19,334	-74%	121	40	-67%
Year 2	840	765	-9%	95,200	29,343	-69%	113	38	-66%
Year 3	1,016	950	-6%	111,478	34,986	-69%	110	37	-66%
Year 4	1,137	1,005	-12%	122,782	38,052	-69%	108	38	-65%
Year 5	1,228	1,061	-14%	131,524	40,390	-69%	107	38	-64%
Years 1-5 Total	**1,228**	**1,061**	**-14%**	**536,036**	**162,106**	**-70%**	**107**	**38**	**-64%**

Table 10-3: 2009 FEI Aggregate Main Extensions Profitability Index

2009 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.44	0.51	-65%
Years 1-5 Total	**1.44**	**0.51**	**-65%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed to the Commission14.
- The variance between years 1-3 forecast and year's 1-3 actual costs is attributable to a combination of variance in costs and attachments.
- 3 FEI customers contained in the sample made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

10.2 *2009 FEVI SAMPLE RESULTS*

The tables below summarize the sample aggregate 2009 main extension results for FEVI.

Table 10-4: 2009 FEVI Aggregate Main Extensions Costs

2009 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEVI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 796,757	$ 951,042	19%
	Service lines and meters	$ 447,529	$ 321,152	-28%
	Year 1 Total	$ 1,244,286	$ 1,272,194	2%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 47,922	$ 183,736	283%
	Year 2 Total	$ 47,922	$ 183,736	283%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 23,961	$ 66,392	177%
	Year 3 Total	$ 23,961	$ 66,392	177%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 18,550	$ 23,160	25%
	Year 4 Total	$ 18,550	$ 23,160	25%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 1,546	$ 69,480	4395%
	Year 5 Total	$ 1,546	$ 69,480	4395%
Years 1-5 Total		**$1,336,265**	**$1,614,962**	**21%**

14 TGI & TGVI Main Extension Report and TGI and Revised Vertical Subdivision Report for 2009 Year End, submitted to the Commission August 18, 2010.

Table 10-5: 2009 FEVI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2009 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
FEVI	Attachments			Consumption (GJ)			Use per Customer		
	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	579	208	-64%	39,644	2,983	-92%	68	14	-79%
Year 2	641	327	-49%	43,890	4,166	-91%	68	13	-81%
Year 3	672	370	-45%	45,438	4,731	-90%	68	13	-81%
Year 4	696	385	-45%	46,403	4,857	-90%	67	13	-81%
Year 5	698	430	-38%	46,493	5,233	-89%	67	12	-82%
Years 1-5 Total	**698**	**430**	**-38%**	**221,868**	**21,969**	**-90%**	**67**	**12**	**-82%**

Table 10-6: 2009 FEVI Aggregate Main Extensions Profitability Index

2009 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.63	0.15	-91%
Years 1-5 Total	**1.63**	**0.15**	**-91%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed to the Commission[15].
- The variance between years 1-3 forecast and year's 1-3 actual costs is attributable to a combination of variance in costs and attachments.
- 5 FEVI customers made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

10.3 *2009 FEI Top 5 Results*

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 10-7 & 10-8	Table 10-9 & 10-10	Table 10-11 & 10-12	Table 10-13 & 10-14	Table 10-15 & 10-16	Table 10-17
Tronson Road	2nd Avenue	Upper Hyde Creek	108 Avenue	University Way	Top 5 P.I. Results

[15] TGI & TGVI Main Extension Report and TGI and Revised Vertical Subdivision Report for 2009 Year End, submitted to the Commission August 18, 2010.

Table 10-7: 2009 FEI Top 5 –Tronson Road Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550000158	Tronson Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 337,574	$ 254,932	-24%
	Service lines and meters	$ -	$ 16,089	
	Year 1 Total	$ 337,574	$ 271,021	-20%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 49,660	$ 11,701	-76%
	Year 2 Total	$ 49,660	$ 11,701	-76%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 49,660	$ 7,313	-85%
	Year 3 Total	$ 49,660	$ 7,313	-85%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 49,660	$ 1,463	-97%
	Year 4 Total	$ 49,660	$ 1,463	-97%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 54,627	$ 5,850	-89%
	Year 5 Total	$ 54,627	$ 5,850	-89%
Years 1-5 Total		**$541,182**	**$297,347**	**-45%**

Table 10-8: 2009 FEI Top 5 – Tronson Road Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Tronson Road 5550000158	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	0	11	0%	0	113	0%	0	10	0%	
Year 2	50	19	-62%	5,878	257	-96%	118	14	-89%	
Year 3	100	24	-76%	11,756	353	-97%	118	15	-87%	0%
Year 4	150	25	-83%	17,634	389	-98%	118	16	-87%	
Year 5	205	29	-86%	24,100	514	-98%	118	18	-85%	
Years 1-5 Total	**205**	**29**	**-86%**	**59,368**	**1,626**	**-97%**	**118**	**18**	**-85%**	

Notes:

- House starts have been slow in this development and account for the lower than anticipated attachment rates. The property continues to be developed and is being marketed. Attachments are expected to increase as house starts begin.
- This project is a large phased subdivision, due to economic reasons the developer has put on hold the final phase. The Company continues to monitor the situation with the developer.

Table 10-9: 2009 FEI Top 5 – 2nd Avenue Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550002931	2nd Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 192,852	$ 180,407	-6%
	Service lines and meters	$ 47,674	$ 27,789	-42%
	Year 1 Total	$ 240,526	$ 208,197	-13%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 65,552	$ 118,471	81%
	Year 2 Total	$ 65,552	$ 118,471	81%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 78,464	$ 168,199	114%
	Year 3 Total	$ 78,464	$ 168,199	114%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 66,545	$ 46,803	-30%
	Year 4 Total	$ 66,545	$ 46,803	-30%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 45,688	$ 58,504	28%
	Year 5 Total	$ 45,688	$ 58,504	28%
Years 1-5 Total		**$496,774**	**$600,174**	**21%**

Table 10-10: 2009 FEI Top 5 – 2nd Avenue Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
2nd Avenue 5550002931	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	48	19	-60%	4,685	655	-86%	98	34	-65%	0%
Year 2	114	100	-12%	11,127	2,293	-79%	98	23	-77%	
Year 3	193	215	11%	18,837	5,787	-69%	98	27	-72%	
Year 4	260	247	-5%	25,376	6,585	-74%	98	27	-73%	
Year 5	306	287	-6%	29,733	8,525	-71%	97	30	-69%	
Years 1-5 Total	**306**	**287**	**-6%**	**89,758**	**23,843**	**-73%**	**97**	**30**	**-69%**	

Table 10-11: 2009 FEI Top 5 – Upper Hyde Creek Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS		Cost of Installation ($)		
FEI 4110025291	Upper Hyde Creek	Original Forecast	Actual	Variance %
Year 1	Mains	$ 61,300	$ 103,212	68%
	Service lines and meters	$ 114,219	$ 99,457	-13%
	Year 1 Total	$ 175,519	$ 202,669	15%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 49,728	
	Year 2 Total	$ -	$ 49,728	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 1,463	
	Year 3 Total	$ -	$ 1,463	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$175,519**	**$253,860**	**45%**

Table 10-12: 2009 FEI Top 5 – Upper Hyde Creek Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER	Attachments			Consumption (GJ)			Use per Customer			
FEI Upper Hyde Creek 4110025291	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	115	68	-41%	13,161	2,475	-81%	114	36	-68%	
Year 2	115	102	-11%	13,161	4,230	-68%	114	41	-64%	
Year 3	115	103	-10%	13,161	4,258	-68%	114	41	-64%	0%
Year 4	115	103	-10%	13,161	4,258	-68%	114	41	-64%	
Year 5	115	103	-10%	13,161	4,258	-68%	114	41	-64%	
Years 1-5 Total	**115**	**103**	**-10%**	**65,805**	**19,480**	**-70%**	**114**	**41**	**-64%**	

Notes:

- Cost overruns associated with a bridge crossing have resulted in significant cost increases.

Table 10-13: 2009 FEI Top 5 – 108 Avenue Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550000647	108 Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 85,317	$ 97,272	14%
	Service lines and meters	$ 14,898	$ 59,967	303%
	Year 1 Total	$ 100,215	$ 157,238	57%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 14,898	$ 21,939	47%
	Year 2 Total	$ 14,898	$ 21,939	47%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 14,898	$ 38,028	155%
	Year 3 Total	$ 14,898	$ 38,028	155%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 14,898	$ 10,238	-31%
	Year 4 Total	$ 14,898	$ 10,238	-31%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 17,878	$ 1,463	-92%
	Year 5 Total	$ 17,878	$ 1,463	-92%
Years 1-5 Total		**$162,787**	**$228,906**	**41%**

Table 10-14: 2009 FEI Top 5 – 108 Avenue Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
108 Avenue 5550000647	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	15	41	173%	1,638	1,195	-27%	109	29	-73%	
Year 2	30	56	87%	3,319	1,467	-56%	111	26	-76%	
Year 3	45	82	82%	5,000	2,293	-54%	111	28	-75%	**0%**
Year 4	60	89	48%	6,681	2,533	-62%	111	28	-74%	
Year 5	78	90	15%	8,699	2,587	-70%	112	29	-74%	
Years 1-5 Total	**78**	**90**	**15%**	**25,337**	**10,075**	**-60%**	**112**	**29**	**-74%**	

Table 10-15: 2009 FEI Top 5 – University Way Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550000180	University Way	Original Forecast	Actual	Variance %
Year 1	Mains	$ 182,972	$ 97,020	-47%
	Service lines and meters	$ -	$ 2,925	
	Year 1 Total	$ 182,972	$ 99,945	-45%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 993	$ 1,463	47%
	Year 2 Total	$ 993	$ 1,463	47%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 25,823	$ 1,463	-94%
	Year 3 Total	$ 25,823	$ 1,463	-94%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 25,823	$ -	-100%
	Year 4 Total	$ 25,823	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 24,830	$ 52,654	112%
	Year 5 Total	$ 24,830	$ 52,654	112%
Years 1-5 Total		**$260,442**	**$155,524**	**-40%**

Table 10-16: 2009 FEI Top 5 – University Way Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
University Way 5550000180	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	0	2	-	0	51	-	0	26	-	
Year 2	1	3	200%	1,750	51	-97%	1,750	17	-99%	
Year 3	27	4	-85%	4,913	65	-99%	182	16	-91%	0%
Year 4	53	4	-92%	8,076	65	-99%	152	16	-89%	
Year 5	78	40	-49%	10,489	533	-95%	134	13	-90%	
Years 1-5 Total	**78**	**40**	**-49%**	**25,228**	**765**	**-97%**	**134**	**13**	**-90%**	

Notes:

- The third phase of this project has been put on hold as there are ROW conflicts and construction issues around crossing an existing large diameter transmission pressure gas pipeline.
- Only the first 325m of this project have been installed to date. Academy Hill Prep School is currently attached to this main in addition to the show home for the new 48 unit vertical-subdivision condominium (Academy Hill) currently under construction. The 48 residential meters and 1 commercial meter at Academy Hill should be active in the fall of 2013.
- Phase 2 of Academy Hill (another 30 unit condominium) will be constructed within the next 2-3 years.

Table 10-17: 2009 FEI Top 5 Main Extensions Profitability Index

2009 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Tronson Road	0.88	0.00	-100%
2nd Avenue	1.25	0.45	-64%
Upper Hyde Creek	1.47	0.36	-76%
108 Avenue	1.02	0.32	-68%
University Way	0.85	0.18	-79%
Years 1-5 Total	**1.09**	**0.26**	**-76%**

10.4 *2009 FEVI TOP 5 RESULTS*

The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 10-18 & 10-19	Table 10-20 & 10-21	Table 10-22 & 10-23	Table 10-24 & 10-25	Table 10-26 & 10-27	Table 10-28
Shawnigan Lake Road	West Coast Road	Wild Ridge Way	Hammond Bay Road	Kettle Creek Station	Top 5 P.I. Results

Table 10-18: 2009 FEVI Top 5 – Shawnigan Lake Road Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550000958	Shawnigan Lake Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 695,444	$ 1,918,065	176%
	Service lines and meters	$ 127,534	$ 61,760	-52%
	Year 1 Total	$ 822,978	$ 1,979,825	141%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 92,640	
	Year 2 Total	$ -	$ 92,640	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 21,642	$ 20,072	-7%
	Year 3 Total	$ 21,642	$ 20,072	-7%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 10,808	
	Year 4 Total	$ -	$ 10,808	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 1,544	
	Year 5 Total	$ -	$ 1,544	
Years 1-5 Total		**$844,620**	**$2,104,889**	**149%**

Table 10-19: 2009 FEVI Top 5 – Shawnigan Lake Road Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Shawnigan Lake Road 5550000958	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	165	40	-76%	14,000	2,133	-85%	85	53	-37%	0%
Year 2	165	100	-39%	14,000	3,607	-74%	85	36	-57%	
Year 3	193	113	-41%	20,315	3,871	-81%	105	34	-67%	
Year 4	193	120	-38%	20,315	4,450	-78%	105	37	-65%	
Year 5	193	121	-37%	20,315	4,477	-78%	105	37	-65%	
Years 1-5 Total	**193**	**121**	**-37%**	**88,945**	**18,538**	**-79%**	**105**	**37**	**-65%**	

Notes:

- Please refer to the "Terasen Gas (Vancouver Island) Inc. Shawnigan Lake Main Extension Report" submitted to the Commission on November 2, 2010 for a detailed review.

Table 10-20: 2009 FEVI Top 5 – West Coast Road Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550000027	West Coast Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 261,699	$ 401,092	53%
	Service lines and meters	$ 155,360	$ -	-100%
	Year 1 Total	$ 417,059	$ 401,092	-4%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 1,544	
	Year 3 Total	$ -	$ 1,544	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 1,544	
	Year 4 Total	$ -	$ 1,544	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$417,059**	**$404,180**	**-3%**

Table 10-21: 2009 FEVI Top 5 – West Coast Road Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
West Coast Road 5550000027	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	201	0	-100%	14,070	0	-100%	70	0	-100%	
Year 2	201	0	-100%	14,070	0	-100%	70	0	-100%	
Year 3	201	1	-100%	14,070	18	-100%	70	18	-74%	0%
Year 4	201	2	-99%	14,070	35	-100%	70	18	-75%	
Year 5	201	2	-99%	14,070	35	-100%	70	18	-75%	
Years 1-5 Total	**201**	**2**	**-99%**	**70,350**	**89**	**-100%**	**70**	**18**	**-75%**	

Notes:

- Mains and service stubs were required to be installed prior to paving due to alignment of main. After main install, market conditions severely deteriorated due to the recession resulting in attachment and load projections not being realized. The development is currently being marketed and attachment potential still exists.
- This project also consisted of a large 4" main used to service the subdivision on a higher elevation. The geo-priced cost forecasting was performed prior to the Companies implementing an enhancement for projects using large diameter pipe. As a result, the forecast costs were underestimated.
- While the project is completed and lots are for sale, housing starts in this development are not occurring, so while opportunity exists and the Companies are engaged in discussing energy solutions with builders, there are no housing starts at this time.

Table 10-22: 2009 FEVI Top 5 – Wild Ridge Way Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS					
FEVI		Cost of Installation ($)			
4110024485	Wild Ridge Way	Original Forecast	Actual	Variance %	
Year 1	Mains	$ 67,155	$ 112,793	68%	
	Service lines and meters	$ 49,468	$ 50,952	3%	
	Year 1 Total	$ 116,623	$ 163,745	40%	
Year 2	Mains	$ -	$ -		
	Service lines and meters	$ -	$ 13,896		
	Year 2 Total	$ -	$ 13,896		
Year 3	Mains	$ -	$ -		
	Service lines and meters	$ -	$ 4,632		
	Year 3 Total	$ -	$ 4,632		
Year 4	Mains	$ -	$ -		
	Service lines and meters	$ -	$ -		
	Year 4 Total	$ -	$ -		
Year 5	Mains	$ -	$ -		
	Service lines and meters	$ -	$ -		
	Year 5 Total	$ -	$ -		
Years 1-5 Total		$116,623	$182,273	56%	

Table 10-23: 2009 FEVI Top 5 – Wild Ridge Way Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Wild Ridge Way 4110024485	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	64	33	-48%	4,480	410	-91%	70	12	-82%	
Year 2	64	42	-34%	4,480	520	-88%	70	12	-82%	
Year 3	64	45	-30%	4,480	636	-86%	70	14	-80%	0%
Year 4	64	45	-30%	4,480	636	-86%	70	14	-80%	
Year 5	64	45	-30%	4,480	636	-86%	70	14	-80%	
Years 1-5 Total	64	45	-30%	22,400	2,837	-87%	70	14	-80%	

Notes:

- There were severe issues with the topography surrounding this development. A prevalence of bedrock combined with drastic changes in elevation led to a difficult running line and a significant increase in costs.

Table 10-24: 2009 FEVI Top 5 – Hammond Bay Road Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS		Cost of Installation ($)		
FEVI 4110001271	Hammond Bay Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 66,340	$ 79,513	20%
	Service lines and meters	$ 15,459	$ 23,160	50%
	Year 1 Total	$ 81,799	$ 102,673	26%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 15,459	$ 13,896	-10%
	Year 2 Total	$ 15,459	$ 13,896	-10%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 15,459	$ 12,352	-20%
	Year 3 Total	$ 15,459	$ 12,352	-20%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 15,459	$ 3,088	-80%
	Year 4 Total	$ 15,459	$ 3,088	-80%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 3,088	
	Year 5 Total	$ -	$ 3,088	
Years 1-5 Total		**$128,175**	**$135,097**	**5%**

Table 10-25: 2009 FEVI Top 5 – Hammond Bay Road Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER	Attachments			Consumption (GJ)			Use per Customer			
FEVI Hammond Bay Road 4110001271	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	20	15	-25%	1,400	180	-87%	70	12	-83%	
Year 2	40	24	-40%	2,800	255	-91%	70	11	-85%	
Year 3	60	32	-47%	3,531	296	-92%	59	9	-84%	0%
Year 4	80	34	-58%	4,262	366	-91%	53	11	-80%	
Year 5	80	36	-55%	4,262	382	-91%	53	11	-80%	
Years 1-5 Total	**80**	**36**	**-55%**	**16,255**	**1,480**	**-91%**	**53**	**11**	**-80%**	

Notes:

- Due to economic reasons the development of this project has slowed dramatically.
- The upper portion of this subdivision is steep and rocky which has contributed to higher costs.

Table 10-26: 2009 FEVI Top 5 – Kettle Creek Station Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550002297	Kettle Creek Station	Original Forecast	Actual	Variance %
Year 1	Mains	$ 57,178	$ 70,261	23%
	Service lines and meters	$ 15,459	$ 13,896	-10%
	Year 1 Total	$ 72,636	$ 84,157	16%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 9,264	
	Year 2 Total	$ -	$ 9,264	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 14,686	$ -	-100%
	Year 3 Total	$ 14,686	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 14,686	$ -	-100%
	Year 5 Total	$ 14,686	$ -	-100%
Years 1-5 Total		**$102,008**	**$93,421**	**-8%**

Table 10-27: 2009 FEVI Top 5 – Kettle Creek Station Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Kettle Creek Station 5550002297	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Ramp-Up Factor
Year 1	20	9	-55%	1,747	65	-96%	87	7	-92%	80%
Year 2	20	15	-25%	1,747	174	-90%	87	12	-87%	
Year 3	39	15	-62%	3,407	174	-95%	87	12	-87%	
Year 4	39	15	-62%	3,407	174	-95%	87	12	-87%	
Year 5	58	15	-74%	5,067	174	-97%	87	12	-87%	
Years 1-5 Total	**58**	**15**	**-74%**	**15,375**	**761**	**-95%**	**87**	**12**	**-87%**	

Notes:

- The anticipated load for this project was not being realized and as a result the Company stopped all new installations until a viable business plan could be worked out with the developer. The developer has since decided not to continue with planned gas connections for the remainder of the subdivision.
- The small size homes in this subdivision have low energy demand and consumers have not been interested in incurring costs to connect and install gas appliances.

1 **Table 10-28: 2009 FEVI Top 5 Main Extensions Profitability Index**

2009 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Shawnigan Lake Road	0.93	0.08	-91%
West Coast Road	1.56	0.00	-100%
Wild Ridge Way	1.91	0.13	-93%
Hammond Bay Road	1.18	0.13	-89%
Kettle Creek Station	1.73	0.06	-96%
Years 1-5 Total	**1.46**	**0.08**	**-94%**

2

11. CONCLUSION AND NEXT STEPS

For the 2014 MX Report, the Companies believe they are in full compliance with the Commission's Decision and Order G-152-07, and Order G-6-08. This Report also addresses the requests of Commission staff and the related additional items identified in Letters L-67-11, L-19-12 and L-60-12.

Appendix A

GENERAL TERMS AND CONDITIONS (DEFINITIONS)

Definitions

Unless the context indicates otherwise, in the General Terms and Conditions of FortisBC Energy and in the rate schedules of FortisBC Energy the following words have the following meanings:

Application Fee	Means the applicable fees as set out in the Standard Fees and Charges Schedule.
Basic Charge	Means a fixed charge required to be paid by a Customer for Service as specified in the applicable Rate Schedule, or the prorated daily equivalent charge – calculated on the basis of a 365.25-day year (to incorporate the leap year), and rounded down to four decimal places.
Biogas	Means raw gas substantially composed of methane that is produced by the breakdown of organic matter in the absence of oxygen.
Biomethane	Means Biogas purified or upgraded to pipeline quality gas, also referred to as renewable natural gas.
Biomethane Service	Means the Service provided to Customers under Rate Schedules 1B for Residential Biomethane Service, 2B for Small Commercial Biomethane Service, 3B for Large Commercial Biomethane Service, 5B for General Firm Biomethane Service,11B for Large Volume Interruptible Biomethane Service, and 30 for Off-System Interruptible Biomethane Sales.
British Columbia Utilities Commission	Means the British Columbia Utilities Commission constituted under the *Utilities Commission Act* of British Columbia and includes and is also a reference to (a) any commission that is a successor to such commission, and (b) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the *Utilities Commission Act* of British Columbia
Carbon Offsets	Means what FortisBC Energy will purchase as a mechanism to balance demand-supply for Biomethane in the event of an undersupply of Biomethane in order to retain the greenhouse gas reductions that Customers would have received from Biomethane supply. One Carbon Offset represents the reduction of one metric ton of carbon dioxide or its equivalent in other greenhouse gases.

Commercial Service	Means the provision of firm Gas supplied to one Delivery Point and through one Meter Set for use in approved appliances in commercial, institutional or small industrial operations.
Commodity Cost Recovery Charge	Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.
Commodity Unbundling Service	Means the service provided to Customers under Rate Schedule 1U for Residential Unbundling Service, Rate Schedule 2U for Small Commercial Commodity Unbundling Service and Rate Schedule 3U for Large Commercial Commodity Unbundling Service.
Conversion Factor	Means a factor, or combination of factors, which converts gas meter data to Gigajoules or cubic metres for billing purposes.
Customer	Means a Person who is being provided Service or who has filed an application for Service with FortisBC Energy that has been approved by FortisBC Energy.
Day	Means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the Service Agreement.
Delivery Point	Means the outlet of the Meter Set unless otherwise specified in the Service Agreement.
Delivery Pressure	Means the pressure of the Gas at the Delivery Point.
Financing Agreement	Means an agreement under which FortisBC Energy provides financing to a Customer for improving the energy efficiency of a Premises, or a part of a Premises.
First Nations	Means those First Nations that have attained legally recognized self-government status pursuant to self-government agreements entered into with the Federal Government and validly enacted self-government legislation in Canada.

Franchise Fees	Means the aggregate of all monies payable by FortisBC Energy to a municipality or First Nations (a) for the use of the streets and other property to construct and operate the utility business of FortisBC Energy within a municipality or First Nations lands (formerly, reserves within the Indian Act), (b) relating to the revenues received by FortisBC Energy for Gas consumed within the municipality or First Nations lands (formerly, reserves within the Indian Act), or (c) relating, if applicable, to the value of Gas transported by FortisBC Energy through the municipality or First Nations lands (formerly, reserves within the Indian Act).
FortisBC Energy	Means FortisBC Energy Inc., a body corporate incorporated pursuant to the laws of the Province of British Columbia under number 0778288.
FortisBC Energy System	Means the Gas transmission and distribution system owned and operated by FortisBC Energy, as such system is expanded, reduced or modified from time to time.
Gas	Means natural gas (including odorant added by FortisBC Energy), propane and Biomethane.
Gas Service	Means the delivery of Gas through a Meter Set.
General Terms & Conditions of FortisBC Energy	Means these general terms and conditions of FortisBC Energy from time to time approved by the British Columbia Utilities Commission.
Gigajoule	Means a measure of energy equal to one billion joules used for billing purposes.
Heat Content	Means the quantity of energy per unit volume of Gas measured under standardized conditions and expressed in megajoules per cubic metre (MJ/m^3).
Hour	Means any consecutive 60 minute period.

Hydronic Heating System	A heating / cooling system where water is heated or cooled and distributes hot water through pipes to radiators or to another style of water-to-air heat exchanger.
Landlord	A Person who, being the owner of a property, has leased or rented it to another person, called the Tenant, and includes the agent of that owner.
Loan	Means the principal amount of financing provided by FortisBC Energy to a Customer, plus interest charged by FortisBC Energy on the amount of financing and any applicable fees and late payment charges.
Main	Means pipes used to carry Gas for general or collective use for the purposes of distribution.
Main Extension	Means an extension of one of FortisBC Energy's mains with low, distribution, intermediate or transmission pressures, and includes tapping of transmission pipelines, the installation of any required pressure regulating facilities and upgrading of existing Mains, or pressure regulating facilities on private property.
Marketer	Means a Person who has entered into an agreement to supply a Customer under Commodity Unbundling Service.
Meter Set	Means an assembly of FortisBC Energy owned metering and ancillary equipment and piping.
Month or Monthly	Means a period of time, for billing purposes, of 27 to 34 consecutive Days.
Municipal Operating Fees	Has the same meaning as Franchise Fees.
Other Service	Means the provision of Service other than Gas Service including, but not limited to, rental of equipment, natural gas vehicle fuel compression, alterations and repairs, merchandise purchases, and financing.

Other Service Charges	Means charges for rental, natural gas vehicle fuel compression service, damages, alterations and repairs, financing, insurance and merchandise purchases, and late payment charges, Franchise Fees, Social Service Tax, Goods and Services Tax or other taxes related to these charges.
Person	Means a natural person, partnership, corporation, society, unincorporated entity or body politic.
Premises	Means a building, a separate unit of a building, or machinery together with the surrounding land.
Profitability Index	The revenue to cost ratio comparing the revenues expected from a Main Extension project to the expected costs over a set period of time.
Rate Schedule	Means a schedule attached to and forming part of this Tariff, which sets out the charges for Service and certain other related terms and conditions for a class of Service.
Residential Premises	Means the Premises of a single Customer, whether single family dwelling, separately metered single-family townhouse, rowhouse, condominium, duplex or apartment, or single-metered apartment blocks with four or less apartments.
Residential Service	Means firm Gas Service provided to a Residential Premises.
Rider	Means an additional charge or credit attached to a rate.
Seasonal Service	Means firm Gas Service provided to a Customer during the period commencing April 1st and ending November 1st.
Service	Means the provision of Gas Service or other service by FortisBC Energy.
Service Agreement	Means an agreement between FortisBC Energy and a Customer for the provision of Service.
Service Area	Has the meaning set out at the end of the Definitions in these General Terms & Conditions.

Service Header	Means a Gas distribution pipeline located on private property connecting three or more Service Lines or Meter Sets to a Main.
Service Line	Means that portion of FortisBC Energy's gas distribution system extending from a Main or a Service Header to the inlet of the Meter Set. In case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises.
Service Related Charges	Include, but are not limited to, application fees, Franchise Fees, and late payment charges, plus Social Services Tax, Goods and Service Tax, or other taxes related to these charges.
Standard Fees & Charges Schedule	Means the schedule attached to and forming part of the General Terms and Conditions which lists the various fees and charges relating to Service provided by FortisBC Energy as approved from time to time by the British Columbia Utilities Commission.
Storage and Transport Charge	Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.
Temporary Service	Means the provision of Service for what FortisBC Energy determines will be a limited period of time.
Tenant	A Person who has the temporary use and occupation of real property owned by another Person.
Thermal Energy	Means thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source), and measured by a thermal meter, to premises of a Vertical Subdivision where the thermal meter is used to apportion the gigajoules of Gas consumed by the Gas fired hydronic heating system among the premises in the Vertical Subdivision.
Thermal Metering	Thermal / heat meters measure the energy which, in a heat-exchange circuit, is absorbed or given up by the heat conveying liquid. The thermal / heat meter indicates the quantity of heat in legal units.
Vertical Subdivision	Means a multi-storey building that has individually metered units and a common Service Header connecting banks of meters, typically located on each floor.

Year	Means a period of 12 consecutive Months.
10^3m^3	Means 1,000 cubic metres.

Appendix B

GENERAL TERMS AND CONDITIONS (SECTION 12)

12. Main Extensions

12.1 System Expansion

FortisBC Energy will make extensions of its Gas distribution system in accordance with system development requirements.

12.2 Ownership

All extensions of the Gas distribution system will remain the property of FortisBC Energy.

12.3 Economic Test

All applications to extend the Gas distribution system to one or more new Customers will be subject to an economic test approved by the British Columbia Utilities Commission. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Main Extension. The Main Extension will be deemed to be economic and will be constructed if the results of the economic test indicate a Profitability Index of 0.8 or greater for an individual main extension.

12.4 Revenue

The projected revenue to be used in the economic test will be determined by FortisBC Energy by:

(a) estimating the number of Customers to be served by the Main Extension;

(b) establishing consumption estimates for each Customer;

(c) projecting when the Customer will be connected to the Main Extension; and

(d) applying the appropriate revenue margins for each Customer's consumption.

The revenue projection will take into consideration the estimated number and type of Gas appliances used and the effect variations in weather conditions throughout the applicable Service Area have on consumption. Customers who intend to install both high efficiency gas fired space (namely an Energy Star rated furnace or boiler) and water heating appliances (tankless water heaters, or water heaters with efficiency rating of 78 percent or greater), will receive a credit of 10 percent of the volume otherwise used for both appliances. Customers who intend to install both high efficiency gas fired space and water heating appliances and attain a minimum of LEED™ (Leadership in Energy and Environmental Design) General Certification will receive a credit of 15 percent of the volume otherwise used for both. In addition, the projected revenue from the applicable Application Fees will be included. Only those Customers expected to connect to the Main Extension within 5 Years of its completion will be considered.

12.5 Costs

The total costs to be used in the economic test include, without limitation:

(a) the full labour, material, and other costs necessary to serve the new Customers including Mains, Service Lines, Meter Sets and any related facilities such as pressure reducing stations and pipelines;

(b) the appropriate allocation of FortisBC Energy's overheads associated with the construction of the Main Extension;

(c) the incremental operating and maintenance expenses necessary to serve the Customers; and

(d) an allocation of system improvement costs.

In addition to the costs identified, the economic test will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

In cases where a larger Gas distribution Main is installed to satisfy future requirements, the difference in cost between the larger Main and the smaller Main necessary to serve the Customers supporting the application may be eliminated from the economic test.

12.6 Contributions in Aid of Construction

If the economic test results indicate a Profitability Index of less than 0.8, the Main Extension may proceed provided that the shortfall in revenue is eliminated by contributions in aid of construction by the Customers to be served by the Main Extension, their agents or other parties, or if there are non-financial factors offsetting the revenue shortfall that are deemed to be acceptable by the British Columbia Utilities Commission.

FortisBC Energy may finance the contributions in aid of construction for Customers. Contributions of less than $100 per Customer may be waived by FortisBC Energy.

12.7 Contributions Paid by Connecting Customers

The total required contribution will be paid by the Customers connecting at the time the Main Extension is built. FortisBC Energy will collect contributions from all Customers connecting during the first five Years after the Main Extension is built. As additional contributions are received from Customers connecting to the main extension, partial refunds will be made to those Customers who had previously made contributions. At the end of the fifth Year, all Customers will have paid an equal contribution, after reconciliation and refunds.

For larger Main Extension projects, FortisBC Energy may use the Main Extension Contribution Agreement for initial contributions. Customers will be billed the contribution amount after the Main Extension is built.

12.8 Refund of Contributions

A review will be performed annually, or more often at FortisBC Energy's discretion, to determine if a refund is payable to all Customers who have contributed to the extension.

If the review of contributions indicates that refunds are due:

(a) individual refunds greater than $100 will be paid at the time of the review;

(b) individual refunds less than $100 will be held until a subsequent review increases the refund payable over $100, or until the end of the five-Year contributory period;

(c) no interest will be paid on contributions that are subsequently refunded;

(d) the total amount of refunds issued will not be greater than the original amount of the contribution; and

(e) if, after making all reasonable efforts, FortisBC Energy is unable to locate a Customer who is eligible for a refund, the Customer will be deemed to have forfeited the contribution refund and the refund will be credited to the other Customers who contributed towards the Main Extension.

12.9 Extensions to Contributory Extensions

When a Main Extension is attached to an existing contributory Main Extension within the five-Year contributory period for the existing extension, the new extension will be evaluated using the Main Extension Test to determine whether a contribution is required. A prorated portion of the total contribution for the existing contributory extension will be assigned to the new extension on the basis of expected use, point of connection, and other factors. Any contributions toward the cost of the existing extension from Customers on the new extension will be used to provide partial refunds to the contributing Customers on the existing extension. The total refunds issued will not exceed the total amount of contributions paid by Customers on the existing extension.

12.10 Security

In those situations where the financial viability of a Main Extension is uncertain, FortisBC Energy may require a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy.

Appendix C

2008 FEI AND FEVI AGGREGATE REPORTING TABLES FROM 2013 MX REPORT

2008 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 352,046	$ 437,819	24%
	Service lines and meters	$ 465,993	$ 217,092	-53%
	Year 1 Total	$ 818,039	$ 654,912	-20%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 24,576	$ 98,330	300%
	Year 2 Total	$ 24,576	$ 98,330	300%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 23,631	$ 125,147	430%
	Year 3 Total	$ 23,631	$ 125,147	430%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 13,233	$ 75,344	469%
	Year 4 Total	$ 13,233	$ 75,344	469%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 12,288	$ 16,601	35%
	Year 5 Total	$ 12,288	$ 16,601	35%
Years 1-5 Total		**$891,766**	**$970,334**	**9%**

2008 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
	Attachments			Consumption (GJ)			Use per Customer		
FEI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	493	170	-66%	57,640	11,540	-80%	117	68	-42%
Year 2	519	247	-52%	60,148	16,991	-72%	116	69	-41%
Year 3	544	345	-37%	62,557	23,151	-63%	115	67	-42%
Year 4	558	404	-28%	63,905	26,837	-58%	115	66	-42%
Year 5	571	417	-27%	65,148	27,451	-58%	114	66	-42%
Years 1-5 Total	**571**	**417**	**-27%**	**309,398**	**105,969**	**-66%**	**114**	**66**	**-42%**

2008 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.60	0.54	-66%
Years 1-5 Total	**1.60**	**0.54**	**-66%**

2008 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEVI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 264,194	$ 298,877	13%
	Service lines and meters	$ 244,921	$ 133,320	-46%
	Year 1 Total	$ 509,114	$ 432,197	-15%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 30,856	$ 55,440	80%
	Year 2 Total	$ 30,856	$ 55,440	80%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 1,929	$ 104,280	5307%
	Year 3 Total	$ 1,929	$ 104,280	5307%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 42,240	
	Year 4 Total	$ -	$ 42,240	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 4,821	$ 6,600	37%
	Year 5 Total	$ 4,821	$ 6,600	37%
Years 1-5 Total		**$546,720**	**$640,757**	**17%**

1

2008 SAMPLE MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER									
	Attachments			Consumption (GJ)			Use per Customer		
FEVI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	254	101	-60%	12,561	3,832	-69%	49	38	-23%
Year 2	286	143	-50%	14,482	5,020	-65%	51	35	-31%
Year 3	288	222	-23%	14,589	6,579	-55%	51	30	-41%
Year 4	288	254	-12%	14,589	7,348	-50%	51	29	-43%
Year 5	293	259	-12%	14,839	7,476	-50%	51	29	-43%
Years 1-5 Total	293	259	-12%	71,060	30,256	-57%	51	29	-43%

2

2008 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.30	0.61	-53%
Years 1-5 Total	**1.30**	**0.61**	**-53%**

3

Appendix D

CORRESPONDENCE FILED AFTER 2012 MX REPORT

ERICA HAMILTON
COMMISSION SECRETARY
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BRITISH COLUMBIA UTILITIES COMMISSION

LETTER L-44-14

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VIA EMAIL
gas.regulatory.affairs@fortisbc.com

August 22, 2014

Ms. Diane Roy
Director, Regulatory Affairs - Gas
FortisBC Energy Inc.
Surrey, BC V4N 0E8

Dear Ms. Roy:

Re: FortisBC Energy Inc. and FortisBC Energy Vancouver Island Inc. (Companies)
Comments Received on the Companies'
2013 Main Extension (MX) and Vertical Sub-division Reports

The British Columbia Utilities Commission (Commission) writes in response to comments received on Letter L-34-14.

The Commission has reviewed the comments and is supportive of the Companies' efforts to consult stakeholders prior to submitting an application. The Commission encourages the Companies to continue with and complete their current consultation process in a timely manner. The Commission expects the Companies to continue working with stakeholders and Commission staff to develop and review a detailed terms of reference, address the concerns raised by the Commission in Letter L-34-14, and file an application for revised main extension policies in the first quarter of 2015. The concerns raised by the Commission in Letter L-34-14 include but are not limited to: 1) the forecasting accuracy of main extension costs, number of attachments, timing of attachments and use per customer, and 2) the application of efficiency credits, contributions in aid of construction, and security deposits.

To support a timely process, the Commission requests the Companies to confirm by December 31, 2014 that they will be filing an application on their main extension policies by March 31, 2015, or the Companies must provide an explanation and justification why they are not, also by December 31, 2014. If the Companies do not commit to filing an application that addresses the Commission's concerns by March 31, 2015, the Commission will establish a process to address the Commission's concerns with the current main extension policies.

The Commission confirms that Commission staff will be assigned to participate in the stakeholder process to develop and review the detailed terms of reference and ensure the Commission's concerns are fully considered. Active participation by Commission staff does not constitute the Commission's support of a future main extension application, nor does it limit the Commission's ability to fully investigate a future application.

Yours truly,

Erica Hamilton

CG/cms
cc: Registered Interveners and participants in the FEU MX workshops:
FBC-PBR-2014-18-RI; FEI-PBR-2014-18-RI; TGVI-TGI-SyX&CPR-RI

Diane Roy
Director, Regulatory Services

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December 19, 2014

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI) and FortisBC Energy Vancouver Island Inc. (FEVI) (collectively the Companies) System Extension and Customer Connection Policies Application (the Application)

Response to Letter L-44-14

On August 22, 2014, the British Columbia Utilities Commission (the Commission) issued Letter L-44-14 in support of the Companies' efforts to consult stakeholders prior to submitting an Application, and encouraged the Companies to continue with and complete the consultation in a timely manner. In Letter L-44-14, the Commission also requested confirmation that a System Extension and Customer Connection Policies application will be filed by March 31, 2015. If such confirmation is not provided, the Companies are required to provide justification, by December 31, 2014, as to why not.

The Companies are committed to a timely, consultative process for submitting the Application related to the system extension policies, as many stakeholders have been anticipating an expedient update of the Companies' policies to make it easier to access natural gas. To date, the Companies have met individually with stakeholders and have led four system extension review workshops to solicit input from a wide cross section of stakeholders with varying knowledge and interests. Further, the Companies respectfully submit that they have met the expectations of the Commission set forth in Letter L-34-14 by successfully developing detailed terms of reference and addressing with stakeholders the concerns brought forward by the Commission in Letter L-34-14. Both of these items will be included in the Application. The majority of the feedback received following the most recent workshop indicates support from stakeholders for the recommendations put forward by the Companies. There was also considerable discussion on matters of provincial policy with respect to attaching new customers and in particular new communities. Additional discussions with key stakeholders will be required prior to filing the Application to clarify the role of government as it relates to natural gas system extension policy.

Pursuant to Order G-152-07 (FEI-FEVI Main Extension (MX) Report) and Order G-6-08 (FEI Vertical Subdivision Report) the Companies are required to file Annual MX reports at the end of the first quarter of each year. Commission Staff at the most recent workshop also noted that these reports are required to be filled annually irrespective of any System Extension Application. These reports involve and consume significant resources to collect and compile the required data. For the 2014 MX report, there are also further reporting requirements resulting from correspondence with Commission staff related to previous year reports. These reports utilize the same staffing resources of the Companies that would be used to compile and file the Application.

As a result of these resource constraints and challenges, the Companies will be unable to complete both the 2014 MX report and file the Application by March 31, 2015. The Companies will submit the 2014 MX report by March 31, 2015, as required under Orders G-152-07 and G-6-08. At this time, the Companies anticipate being in a position to submit the Application in the second quarter of 2015. The Companies will notify the Commission should circumstances arise affecting this anticipated timing.

If further information is required, please contact Mike Metza at 604-592-7852.

Sincerely,

FORTISBC ENERGY INC.

Original signed by: Ilva Bevacqua

For: Diane Roy

cc (email only): Workshop Participants

ERICA HAMILTON
COMMISSION SECRETARY
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BRITISH COLUMBIA UTILITIES COMMISSION

LETTER L-34-14

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VIA EMAIL
gas.regulatory.affairs@fortisbc.com

June 19, 2014

Ms. Diane Roy
Director, Regulatory Affairs - Gas
FortisBC Energy Inc.
Surrey, BC V4N 0E8

Dear Ms. Roy:

Re: FortisBC Energy Inc. and FortisBC Energy Vancouver Island Inc.
2013 Main Extension (MX) and Vertical Sub-division Reports

The British Columbia Utilities Commission (Commission) acknowledges receipt of the 2013 Main Extension (MX) and Vertical Sub-division Reports (Report) submitted by FortisBC Energy Inc. (FEI) and FortisBC Energy Vancouver Island Inc. (FEVI) (collectively, the Companies). Considering the 2013 MX Report results, including the five year results for the 2008 mains extension year, which appear to show a significant under-recovery of those mains extension costs, and the Commission's observations on the Companies' forecasting methods and security and ratepayer protection policies, the Commission seeks comment on the Companies' main extension performance and policies before deciding how to proceed.

Specifically, the Commission requests the Companies and interested parties to provide comments to the Commission, on or before July 15, 2014, on the items outlined on page 5 of this Letter.

Background

On July 31, 2007, pursuant to the *Utilities Commission Act*, Terasen Gas Inc. (TGI) and Terasen Gas (Vancouver Island) Inc. (TGVI), predecessors to FEI and FEVI, jointly filed an application to amend the Terms and Conditions of each utility's Tariff with respect to charges for system extensions and customer attachment and connections (Application).

On December 6, 2007, by Order G-152-07, the Commission issued its Decision on the Application. In its Decision, the Commission Panel directed TGI and TGVI to file with the Commission on an annual basis, within 90 days of calendar year end, a main extension report containing certain information.

On March 27, 2014, FEI and FEVI jointly submitted to the Commission their 2013 MX Report, which includes results based on 5 years of data for 2008 main extensions.

The Commission acknowledges that the Companies are currently engaged in a stakeholder review of their main extension policies. However, it appears that the Companies' process includes neither a review of the Companies' performance, nor a review of the specific concerns that the Commission notes below. The Commission also believes a more timely review process is appropriate.

Overview of Issues

On August 18, 2010, TGI and TGVI filed a revised 2009 MX Report in which they affirmed "...the results of the main extensions at the end of the five-year time period is the appropriate time to determine the appropriateness of the forecasts developed at the time of the main installation request..." (Revised TGI and TGVI 2009 MX Report, p. 15). As the 2013 MX Report includes results for 2008 main extensions at the end of the five-year time period, the Commission considers it time to determine the appropriateness of the Companies' main extension forecasts.

> "The Profitability Index [PI] 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. While there are many components factored into the calculation of this ratio, the following formula provides a summary of the major components:

$$\text{P.I.} = \frac{\substack{\textbf{Net Present Value of Net Cash Inflows} \\ \text{(Delivery Margin + Connection Fees – O\&M - System Improvement Charge – Property Tax – Income Tax)}}}{\substack{\text{(Mains, Services, Meter Costs)} \\ \textbf{Net Present Value of Capital Costs}}}$$

> Accompanying the MX Test formula are the following FEI and FEVI MX Test threshold criteria that have been approved by the Commission under Order No. G-152-07:

- 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 is required to bring the PI up to the 0.8 threshold, before the system extension can be built.
- An aggregate threshold PI of 1.1 is to be used for the portfolio of main extensions completed on an annual basis." (2012 MX Report, p. 10)

A PI of less than 1.0 indicates that the net present value of the net cash inflows (actual net cash inflows in the reporting period plus the forecast net cash inflows) over twenty years is less than the discounted present value of the actual capital costs of attaching customers in the first five years.

For the 2008 main extension year, the Companies report actual individual PIs and actual aggregate PIs below the minimum required thresholds of 0.8 and 1.1, respectively.

The Commission is concerned that the 2008 aggregate PI results over the five year period were below 1.0, indicating that existing ratepayers might be exposed to an undue cost burden as a result of the expansion of the distribution system to attach these new customers.

For ease of reference, the five year results for the 2008 main extension year provided in the Report are repeated below:

2008 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)

FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.60	0.54	-66%
Years 1-5 Total	1.60	0.54	-66%

(2013 MX Report, p. 113)

2008 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Trans-Canada Hwy	1.00	0.07	-93%
Juniper Road	1.70	0.00	-100%
Crystal Creek Drive	1.00	0.08	-92%
61A Avenue	1.38	0.59	-57%
Rio Drive	1.00	0.09	-91%
Years 1-5 Average	1.22	0.17	-86%

(2013 MX Report, p. 121)

2008 SAMPLE MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Year 1 Year 2 Year 3 Year 4 Year 5	1.30	0.61	-53%
Years 1-5 Total	1.30	0.61	-53%

(2013 MX Report, p. 115)

2008 TOP 5 MAIN EXTENSIONS PROFITABILITY INDEX (PI)			
FEVI	Original Years 1-5 Forecast	Re-calculated PI with actual data	Variance %
Players Drive	1.55	0.24	-84%
French Road	1.22	0.16	-87%
Hutchinson Road	1.40	0.46	-67%
Sewell Road	1.03	0.48	-54%
Phillips Road	0.88	0.00	-100%
Years 1-5 Average	**1.22**	**0.27**	**-78%**

(2013 MX Report, p. 126)

The Commission has identified two areas of concern it believes are contributing to the gap between forecast PIs and actual PIs over this period. These are:

1) forecasting accuracy, and
2) security and existing ratepayer protection in the event that costs, attachments and/or consumption do not materialize according to forecast estimates.

1. Forecasting Accuracy

Forecasting accuracy refers to the accuracy of the inputs used in the forecast PI calculations. Inputs include, but are not limited to, main extension costs, number of attachments, timing of attachments, use per customer, and application of efficiency credits. Forecasting lower costs, a greater number of attachments, earlier attachments, and/or a higher use per customer than actual may result in a main extension meeting the main extension test with less (or no) contribution from the customer(s) than what the customer(s) should have contributed.

There have been main extensions where actual costs have been higher than the Companies' forecasts and this has contributed to actual individual PIs being lower than the required minimum threshold of 0.8, for example, Shawinigan Lake (2013 MX Report, Table 137, p. 105 and Table 147, line 1, p. 111) and Crystal Creek (2013 MX Report, Table 158, p. 118, Table 164, line 3).

There have also been main extensions where actual attachments have been fewer and later than the Companies' forecasts and this too has contributed to actual individual PIs being lower than the required minimum threshold of 0.8, for example, Juniper Road (2013 MX Report, Table 157, p. 117) and Rio Drive (2013 MX Report, Table 163, p. 120). The Companies have stated that the 2008 main extension year was impacted by the economic downturn and is why attachments did not materialize as forecasted (Revised TGI and TGVI 2009 MX Report, p. 1).

For almost every main extension, actual consumption (use) per customer has been significantly less than forecast (2013 MX Report, pp. 41-126). In the Executive Summary of the Report, the Companies state that actual consumption levels are consistent with new customers (2013 MX Report, pp. 1-2).

The Companies explain:

> "Consumption is calculated by determining the annual usage estimates by appliance type derived from operational experience and the Companies' own Residential End Use Study ("REUS") for <u>**existing**</u> customers." (Emphasis added) (2013 MX Report, p. 11)
>
> "However, it is important to note that new customers' (<u>**actual**</u>) consumption patterns <u>**differ from existing customers**</u> due the adoption of current efficiency technology in housing and that the forecast levels used in MX Test represent the consumption levels of all existing customers on the Companies' distribution system who connected to the system..." (Emphasis added) (2013 MX Report, p. 1)

From the data provided in previous reports, the primary difference between new customers and existing customers is that new customers' consumption is less than existing customers' consumption (2011 MX Report, pp. 21-22). Forecasting new customer consumption based on existing customer usage estimates will result in inaccurate PI forecasts because new customers are expected to use less gas than existing customers.

It also appears that when the Companies forecast individual PIs, they are applying 10 percent and 15 percent efficiency credits to existing customer consumption levels (2013 MX Report, p. 12). If this is correct, it would act to further inflate consumption forecasts for new customers.

> "Customers who install both high efficiency gas fired space and water heating receive a credit of 10 percent of the volume otherwise used for both appliances." (2013 MX Report, p. 12)
>
> "Customers who install both high efficiency gas fired space and water heating appliances and attain a minimum of LEED™ (Leadership in Energy and Environmental Design) General Certification receive a credit of 15 percent of the volume otherwise used for both." (2013 MX Report, p. 12)

Using existing customers' consumption estimates would tend to cause forecasts for new customers' net revenue and therefore forecasts for new customers' individual PIs to be overstated. Similarly, adding efficiency credits to existing customers' consumption estimates would tend to cause forecasts for new customers' net revenue and therefore forecasts for new customers' individual PIs to be further overstated. Overstating forecasts for new customers' individual PIs would tend to lead to overstating forecasts for new customers' aggregate PIs.

Therefore, to achieve actual individual PIs of at least 0.8 and actual aggregate PIs of at least 1.1, the forecast individual target PIs must be higher than 0.8 and the forecast target aggregate PIs must be higher than 1.1.

2. Security and Existing Ratepayer Protection

Section 12.6 of the Companies' General Terms and Conditions reads:

> "Contributions in Aid of Construction - If the economic test results indicate a Profitability Index of less than 0.8, the Main Extension may proceed provided that the shortfall in revenue is eliminated by contributions in aid of construction..." (2013 MX Report, Appendix B, Section 12.6, p. 12-2).

Section 12.10 of the Companies' General Terms and Conditions reads:

> "Security - In those situations where the financial viability of a Main Extension is uncertain, FortisBC Energy may require a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy." (2013 MX Report, Appendix B, Section 12.10, p. 12-3)

It is possible, had the Companies obtained sufficient contributions in aid of construction or other securities for main extensions where the actual costs were higher, attachments were fewer or later, and/or customer consumption was lower than forecasted, the potential exposure to existing ratepayers of an undue cost burden as a result of the expansion of the distribution system to attach new customers would have been mitigated.

Submissions Sought

Considering the 2013 MX Report results, including the five year results for the 2008 mains extension year, which appear to show a significant under-recovery of those mains extension costs, and the Commission's observations on the Companies' forecasting methods and security and ratepayer protection policies, the Commission seeks comment on the Companies' main extension performance and policies before deciding how to proceed. Specifically, the Commission requests the Companies and interested parties to provide comments to the Commission, on or before July 15, 2014, on the following:

1. What should be the scope and process for a more detailed review of the Companies' main extension performance and policies?

2. Comment on the Companies' security and ratepayer protection policies. What changes to these policies should be made, if any?

3. Comment on the Companies' forecasting performance. What changes to the Companies' forecasting methods should be made, if any?

4. Comment on the urgency of a review and what should the Companies and the Commission should do in the interim?

Yours truly,

Erica Hamilton

CG/cms

cc: Registered Interveners
FBC-PBR-2014-18-RI; FEI-PBR-2014-18-RI; TGVI-TGI-SyX&CPR-RI

Dennis Swanson
Director, Regulatory Affairs

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July 9, 2014

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI) and FortisBC Energy (Vancouver Island) Inc. (FEVI) (collectively the FEU or the Companies) 2013 Year End Report for:

- **FEI-FEVI Main Extension (MX) Report – British Columbia Utilities Commission (the Commission) Order G-152-07 Compliance Filing; and**
- **FEI Vertical Subdivision Report – Commission Order No. G-6-08 Compliance Filing**

The Companies' Response to Commission Letter L-34-14

The Companies have reviewed the Commission's Letter L-34-14 and provide the following response.

While the Companies do not agree with the observations of the Commission with respect to forecast accuracy and the Companies' security and ratepayer protection policies, the Companies recognize that there are concerns with the system extension and customer connection policies (the Policies) in place and that they need to be reviewed and alternatives considered. To address these concerns, the Companies have begun a consultative process by engaging with a wider group of stakeholders, including Commission staff, who are interested in the Policies. Following this stakeholder engagement and consultative process on the Policies (the Consultation Process), the Companies intend to file with the Commission the results of the Consultation Process and a proposal for changes to the Policies intended to resolve the concerns. The Consultation Process will allow the FEU to bring forward a proposal that is informed by a broad array of stakeholders and considers issues raised that are more broadly impacted by the Policies, both directly and indirectly. Continuation of the Consultation Process will allow the FEU to put forward a proposal with the necessary evidence to enable the Commission to assess the proposal for changes to the Policies and potential alternatives. In the FEU's submission, any alternative or additional process introduced at this time by the Commission would not be practical because it would be duplicative, would result in additional time and costs for participants, and would likely cause confusion with the existing Consultation Process that is already underway. Further, the FEU believe that given the regulatory calendar of proceedings currently before the Commission, continuing with the Consultation Process already underway presents the most efficient, effective, timely, thorough, and informed review of the Policies.

In this letter, the FEU provide the Commission with some details on the FEU's Consultation Process that is underway and then respond to the Commission's four questions as set out in Letter L-34-14.

Background on Existing Stakeholder System Extension Review Process

After the submission of the 2011 Main Extension Report, the Companies engaged EES Consulting, Inc. (EES Consulting) to examine the system extension and customer connection policies, tests and practices in other jurisdictions. The purpose was to determine if the current FEU Policies should be reviewed more substantially. Upon receipt of the report from EES Consulting (the EES Report) the FEU determined that a review of the Policies was required. The Companies submitted the EES Report as part of the 2012 Main Extension Report[1]. Following submission of the 2012 Main Extension Report, the Companies began meeting with various individual stakeholders to seek their input on proceeding with a review of the Policies to address gaps and concerns in the current Policies as they relate to the different types of system extension customers. On February 18, 2014, the Companies held the first stakeholder workshop on the Policies, which was attended by Commission Staff. The workshop was designed to educate and inform stakeholders on the specific issues arising from the Polices, such as:

- the inability of the system extension test to recognize the full benefits associated with connecting a new customer;
- the inadequacy of the current Policies to enable off system communities to access natural gas in a reasonable and cost effective manner; and
- the overall difficulty all customers face in interpreting and understanding the costs associated with a natural gas connection as a consequence of the current Policies.

As a result of the workshop, participants agreed to proceed further with the review of the Policies. A subsequent workshop was then held on June 18, 2014, where stakeholders, including Commission Staff, provided input on a Terms of Reference (the Stakeholder Terms of Reference) for the development of new Policies. The Stakeholder Terms of Reference are attached as Appendix B.

The Companies are currently using the Stakeholder Terms of Reference as a framework for the development of several options related to the Policies which will be reviewed in detail at a third workshop scheduled for October 8, 2014. A fourth and final workshop will be held during the fourth quarter of 2014. The schedule of the Consultation Process is proceeding as quickly as reasonably possible given the availability of the participants.

The goal of the workshops and the Consultation Process is to arrive at a new set of Policies and a system extension test designed to address the concerns of all stakeholders related to

[1] FEI-FEVI Main Extension Report for 2012 Year End – submitted March 28, 2013.

the current Policies. The planned outcome of the Consultation Process is the filing of an application with the Commission in the first quarter of 2015, for approval of new Policies which have the support of stakeholders.

The Companies note that Letter L-34-14 was provided only to Registered Interveners involved in past Commission proceedings and that the distribution list did not include some of the stakeholders participating in the Consultation Process already underway. As these stakeholders have already invested their time, resources and attention to the current Consultation Process for review of the Policies, the FEU have forwarded a copy of Letter L-34-14 and this response by the FEU to the list of stakeholders involved in the Consultation Process, which is provided in Appendix A.

The FEU believe that the Consultation Process already underway with stakeholders to review the Policies should proceed as planned, which will allow the FEU to engage and work with a broad range of stakeholders collaboratively, and then bring forward a proposal to the Commission for changes to the existing Policies, including the system extension test and reporting requirements. As such, the FEU's general response to the Letter L-34-14 is that no additional or further process is needed at this time, but rather the FEU should continue with the Consultation Process that is already underway.

Response to Commission Questions

The FEU have provided responses to the particular questions posed by the Commission below. For reference, the four questions posed by the Commission in L-34-14 are as follows:

1. *What should be the scope and process for a more detailed review of the Companies' main extension performance and policies?*
2. *Comment on the Companies security and ratepayer protection policies. What changes should be made if any?*
3. *Comment on the Companies' forecasting performance. What changes to the Companies' forecasting methods should be made, if any?*
4. *Comment on the urgency of a review and what should the Companies and Commission do in the interim?*

The FEU provide their responses below.

1. What should be the scope and process for a more detailed review of the Companies' main extension performance and policies?

The FEU believe the appropriate scope and process for a review is already set out in the Stakeholder Terms of Reference included as Appendix B. The Stakeholder Terms of Reference reflects the recommended scope and process agreed to by stakeholders involved in the FEU's Consultation Process on the Policies, and includes the issues raised by Commission Staff on reporting and performance.

Stakeholders have indicated that the purpose of the Consultation Process should be to examine broad policy issues and the impacts on various customer types. During the workshop, Commission Staff have raised the issue of the differences between the system extension test and the subsequent system extension reporting. The Companies' intention, as stated during the workshop, is that once stakeholders arrived at a supported set of Policies, the appropriate level of reporting and associated methodologies should be examined at that time. As seen in the Stakeholder Terms of Reference in Appendix B, performance and reporting are included as a part of the scope of the Consultation Process.

Given the interest of many stakeholders in the Policies, the FEU believe that the Consultation Process that the FEU have commenced is an appropriate process to undertake, prior to any Commission review of the Policies. The FEU's Consultation Process will lead to an Application by the FEU that will have the benefit of stakeholder consultation and will facilitate a complete review by the Commission.

2. Comment on the Companies security and ratepayer protection policies. What changes should be made if any?

The FEU have consistently followed the parameters established by the Commission for the system extension test, Contributions In Aid of Construction (CIACs) and security. However, the existing system extension reporting provides misleading results that should not be used to determine the required degree of rate payer protection. In addition, the protection of existing ratepayers must be balanced with the requirements to serve new customers and the expectations of new customers that they will not be unduly burdened when connecting to the system.

Based on the quote below, it appears that the Commission has determined that ratepayer protection policies need to be assessed based on the results of the system extension report, a specific selection of which was included in Letter L-34-14. Letter L-34-14 states:

> *"It is possible, had the Companies obtained sufficient contributions in aid of construction or other securities for main extensions where the actual costs were higher, attachments were fewer or later, and/or customer consumption was lower than forecasted, the potential exposure to existing ratepayers of an undue cost burden as a result of the expansion of the distribution system to attach new customers would have been mitigated."*[2]

The Companies respectfully disagree with the suggestion that there is "…potential exposure to existing ratepayers of an undue cost burden…" The system extension report results should not be used to determine whether ratepayers are exposed to an undue cost burden. The system extension test cannot measure the final economic impact of a system extension on ratepayers and, as discussed in response to question Number 3 below, the current associated system extension reporting construct is flawed in that it is simply a re-forecast of the original forecast test. Instead, any decision to change the current Policies should be based on the outcome of the Consultation Process that is currently underway and the FEU's subsequent application to the Commission.

The Companies believe that before the levels of ratepayer protection can be examined, a more representative measure of the financial impacts of a system extension on ratepayers must be devised through the Consultation Process. Furthermore, rate payer protection policies should then be defined within the context of a new set of Policies generally. General

[2] L-34-14, page 5.

ratepayer protection policies will be defined and examined in conjunction with the system extension test options that will be discussed in the third workshop (see Appendix B for detail).

For clarity, further explanation is provided of ratepayer protection policies, the system extension test, CIACs and security:

i. Rate Payer Protection Policies & the System Extension Test:

The current system extension test can be classified as a "ratepayer protection policy" in that the customer must pass the test before being connected to the system. When a customer calls to connect, the Companies use information known at the time and apply that information to the system extension test as approved by the Commission. This ultimately determines if the customer must contribute to the cost of the extension. In the event of a required contribution, the customer must provide a CIAC in order to proceed with their connection (CIACs are discussed below). The current system extension test creates a layer of protection for existing ratepayers by providing a forecast figure that is intended to generally reflect the costs and benefits of connecting a new customer during the first five years of the extension. The test adds a layer of rate payer protection and helps the Companies assess whether a customer should pay a portion of the connection cost based on a set of conservative assumptions. A table describing the inputs and assumptions used in the system extension test and approved by the Commission can be found in Appendix C.

ii. CIAC (Contribution In Aid of Construction):

A CIAC occurs when the system extension test determines that a customer must pay a portion of the cost to reduce the amount of capital the Companies put into an extension and is based upon the rules in the Tariff. A CIAC may also be refunded in whole or in part as additional customers attach to the system.

The Companies must run the approved system extension test in the same manner for all customers based on input parameters such as the total cost, number of attachments and types of appliances that are forecast to occur during the first five years of the system extension. The approved system extension test input parameters and methodologies follow the BCUC Utility System Extension Test Guidelines[3] and are most recently approved by Commission Order G-152-07.

iii. Security:

The FEU believe the security provisions within the Tariff, and implemented by the Companies, are appropriate and that to strengthen these mechanisms at this time would punish and impose costs on developers further restricting the ability to add customers.

The Companies have the option to request security if they are uncertain of a customer's commitment to install the specific appliances, in the time frame expected, used in the forecast test. Security can provide a further level of ratepayer protection in the event a builder or developer did not deliver on their commitments. The Companies have the ability under Section 12.10 of the General Terms and Conditions of the FEI and FEVI

[3] BCUC Utility System Extension Test Guidelines, issued September 5, 1996.

tariffs to ask for security. However, it should be noted that security is seen by some developers and customers as a punitive measure. Developers do have control over what appliances are in the house/unit but do not control the end use customer's usage or the exact time frame that the customer connects to the gas system.

As can be seen from the above, the Companies security and ratepayer protection policies are inherently connected to the system extension test which itself is a ratepayer protection policy. As such, changes, if any, to these Policies should be made with the benefit of input from the Consultation Process currently underway and the resulting application that the FEU will file with the Commission.

3. Comment on the Companies' forecasting performance. What changes to the Companies' forecasting methods should be made, if any?

The FEU believe that the forecasting performance is appropriate, follows approved mechanisms, and that no immediate change is required. However there are inherent flaws in the way in which performance is measured in the current system extension test annual reporting requirements. Making changes to one aspect of the test without consideration of the entire test could lead to unintended consequences and issues of intergenerational inequity. The FEU therefore believe that any changes to the Companies' forecasting methods should be made with the benefit of and informed by the Consultation Process underway and the resulting application to be made to the Commission by the FEU.

The current system extension test, as approved by the Commission, uses a variety of agreed upon forecasted inputs to serve as a proxy for the expected actual economic performance of a system extension over a certain period of time. (Further details on the test inputs, their assumptions, and their impact on the system extension results are discussed in Appendix C). The system extension test is meant as a mechanism to try to ensure that existing rate payers are not unduly harmed by the addition of new customers and that the barrier to attach for new customers is not too high. The test is a forecast only and therefore does not truly depict the actual economic impact on the system over the life of the asset. As noted above and further reviewed below, the annual reporting mechanism uses different inputs than the original forecast to create a "re-forecast" and therefore cannot, in its current format, be used for reliable comparison. Actual performance of a main can only be determined at the end of the useful life of the asset.

The Companies believe that both the existing system extension test and reporting underestimate the benefit and overestimate the cost impact of Main Extensions on the FEU's existing customers. With respect to the Companies' forecasting performance, there are three issues that need to be taken into consideration:

(1) customer attachments have not always aligned with forecasts;

(2) the current average use per appliance has been lower than the historic use; and

(3) there are attachments that occur beyond the first five years which are not taken into account nor examined through the current system extension test reporting.

Note that these are all aspects of the system extension test that will be reviewed in the Consultation Process currently underway.

A more detailed discussion of the specific aspects of forecasting performance reflected in the annual reports to the Commission is provided below.

i. Actualized Use per Customer

The Companies' consumption forecasts used in the system extension test are based on the best available information and data at the time of formulation. The current methods draw forecasts directly from the actual consumption of all existing customers and are separated based on geographic region and appliance type. At the time of forecast, the expected annual consumption values derived by the Companies is accurate in that they are reflective of the existing customer base.

When the Companies apply the system extension test for a new customer they use the average consumption by appliance type based on the average of all existing customers based on the results of the Residential End Use Study (REUS) as approved by BCUC Order G-152-07. The average consumption provides a proxy for the revenue portion of the system extension test which directly impacts the test result and ultimately how much a customer will have to pay to connect to the system.

A new customer, however, may consume less gas than the existing average because new customers generally connect with highly energy efficient appliances and buildings (as opposed to existing customers who may have a mix of new efficient appliances and buildings as well as inefficient housing and appliance stock). Furthermore, whether new or existing, the Companies cannot control how much gas a particular customer will use in each appliance. A customer may have a furnace installed but could use the appliance differently depending upon personal habits.

The FEU met with Commission staff and agreed to use actual consumption when re-calculating and re-forecasting the test for reporting purposes. Given that this consumption value is different than what the Commission approved for the original test, the re-forecast test result will typically be lower than the original test result. This does not necessarily indicate a fault in the system extension test or other aspects of the Policies but rather indicates a potential misalignment with the system extension test and the system extension reporting, which is one of the reasons why the system extension test and any reporting that may be required are being re-examined through the ongoing Consultation Process.

While Letter L-34-14 indicates that forecasting consumption may be a negative issue, the Companies believe that a lower consumption value for new customers is a positive outcome as it is indicative of and reflects the success of recent energy efficiency initiatives promoted by the provincial government and the Companies through its Energy Efficiency and Conservation programs. As indicated in Appendix B, stakeholders have indicated that promoting energy efficiency is a key priority for the system extension review.

It is also important to note that the test does not consider customers who connect to the system beyond the first five years and, therefore, no consideration is given to the additional benefits these further customer connections and their resulting gas consumption have to the system and to all FEU customers.

ii. Number of Attachments

Customer attachments to the Companies' distribution system and the BC housing market are closely related and both are highly cyclical in nature. In general, the Companies work closely with a wide range of potential customers from homeowners to large developers to develop good-faith estimates of the appliances and expected time of attachments on new system extension projects. However, similar to other utilities such as water and electricity, the Companies' forecasts are affected by economic conditions and a multitude of other variables which can result in a variance between forecast and actual attachments. In most cases, unrealized attachments are simply delayed, and when considered beyond their respective forecast year, the majority of forecasted attachments will materialize.

The current reporting uses a methodology of re-forecasting attachments that presents the worst case scenario for attachments. As a result, the forecasting performance of attachments is not reflective of actual performance over the life of the assets.

In particular, based on the current reporting the Companies are required to ignore all future potential on a system extension. For example if a builder of a subdivision expects to have 10 homes completed by the end of the first year, and was only able to complete 5 then the re-forecasted attachments assume that only 5 homes will ever attach to the system. This significantly understates the system extension test results thereby providing re-forecasted results that cannot be compared with the original forecast and are not representative of the actual performance of the extension over its useful life. In reality, the missing 5 attachments in the example will likely appear in the future, as will additional, un-forecasted attachments.

As demonstrated, the FEU believe that the forecasting performance is appropriate, follows approved mechanisms, and that no immediate change is required. The FEU therefore believe that any changes to the Companies' forecasting methods should be made with the benefit of, and informed by, the Consultation Process underway and the resulting application to be made to the Commission by the FEU. This has been captured in the Stakeholder Terms of Reference as indicated in Appendix B.

4. Comment on the urgency of a review and what should the Companies and Commission do in the interim?

The Companies believe that a review of the Policies is warranted as evidenced by the process it has already begun with stakeholders, and that the Policies should remain unchanged in the interim. The urgency of the review is driven in part by those customers and communities who do not already have access to natural gas but want the option to use natural gas in their homes and businesses.

The Consultation Process currently underway is intended to define a new set of Policies that will address the needs of the different types of customers and stakeholders, including the concerns noted by the Commission.

The Companies submit that the current Policies should remain unchanged until the completion of the Consultation Process, the subsequent filing of an application by the FEU, and final disposition of the FEU's application by the Commission. Any short-term changes put in place, either interim or permanent, would be a reactionary measure which could have unintended and unforeseen consequences, would result in confusion, and could potentially cause an undue burden on both new and existing customers.

Conclusion

The FEU believe that initiating an additional process at this time would confuse the existing Consultation Process already underway and would be inconsistent with what has been agreed upon by stakeholders involved in the current Consultation Process. For the reasons discussed above:

1. The existing Consultation Process should continue.
2. The current rate payer protection policies are appropriate and are best left in place until such time as the Consultation Process has been completed, and changes, if any, can be presented with the benefit of evidence and input from the Consultation Process.
3. The Companies forecasting performance is reasonable at this time and meets Commission's direction. However, as part of the existing Consultation Process, forecasting matters will be reviewed and addressed as may be required.
4. To the extent that there is any urgent need to review the Policies, the existing Consultation Process should continue as it is the most efficient, effective and timely process in which to address all issues.

Yours very truly,

FORTISBC ENERGY INC.
FORTISBC ENERGY (VANCOUVER ISLAND) INC.

Original signed:

Dennis Swanson

Attachments

cc (email only): Stakeholders participating in the Consultation Process
Registered Parties to the:

- FEI 2014-2018 PBR Proceeding
- FBC 2014-2018 PBR Proceeding
- FEU 2007 System Extension Proceeding

Appendix A

ADDITIONAL LETTER RECIPIENTS

Stakeholder	Attendee	Title
BC Chamber of Commerce	**Susan Payne**	Executive Director, Ucluelet Chamber of Commerce
Commercial Energy Consumers Association of British Columbia	**David Craig**	Executive Director
Chawathil First Nation	**Norman Florence**	Council Member
EES Consulting	**Gail Tabone**	Senior Consultant, EES Consulting
Fraser Valley Regional District	**Lloyd Foreman**	Director, Electoral Area A
Fraser Valley Regional District	**Dennis Adamson**	Director, Electoral Area B
MJT - Ministry of Jobs, Tourism and Skills Training	**Robert Wood**	Acting Director, Major Investments Office
MLA Boundary - Similkameen	**Colleen Misner**	Constituency Assistant to Linda Larson, MLA
Okanagan - Similkameen Regional District	**George Bush**	Board Member
PNG – Pacific Northern Gas	**Janet Kennedy**	Vice President, Regulatory Affairs and Gas Supply
PNG – Pacific Northern Gas	**Peter Schriber**	Manager, Financial Planning & Business Development
PRRD - Peace River Regional District	**Karen Goodings**	Board Director
Seabird Island Band	**Brian Titus**	Consultant
Seabird Island Band	**Chief Clem Seymour**	Chief
Yale First Nation	**Steven Patterson**	Natural Resource Manager
First Nations Energy and Mining Council	**Katie Terhune**	Consultant

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Appendix B
STAKEHOLDER TERMS OF REFERENCE

1. STAKEHOLDER PACKAGE FOLLOWING JUNE 18, 2014 WORKSHOP

This letter provides a summary of the discussions to date regarding the stakeholder based review of FortisBC's system extension policies (the "Project"). It is organized into the following sections:

- Part 1: Request of Stakeholders outlines the request for comments from stakeholders
- Part 2: Background provides a brief history of the Project
- Part 3: Terms of Reference outlines the Project purpose, process, roles and responsibilities, scope and timeline
- Part 4: Guiding Principles outlines the relevant regulatory history along with a summary of the stakeholder feedback in this area
- Appendix contains a list of participants attending the two workshops

PART 1: REQUEST OF STAKEHOLDERS

On June 18, 2014, FortisBC held its second system extension review workshop with stakeholders. As agreed in the workshop, FortisBC has summarized the feedback from stakeholders and is requesting comments before finalizing the terms of reference and guiding principles. This document will then be used to determine the nature of the analysis to be completed in advance of our third stakeholder workshop, tentatively scheduled for October 2014.

Please provide any comments on the document, especially the terms of reference and guiding principles, to mike.metza@fortisbc.com by July 4, 2014.

PART 2: BACKGROUND

In the fourth quarter of 2013, FortisBC met individually with prospective stakeholders. Preliminary support was established for conducting a review of FortisBC's system extension policies in a consultative manner. Stakeholders identified their time constraints and requests were made to schedule the review starting February 2014.

On February 18, 2014 FortisBC held an initial system extension stakeholder workshop. The primary focus of the workshop was to provide stakeholders with a general understanding of current system extension policies and their role in connecting new customers to FortisBC's natural gas distribution system. Throughout the workshop, participants heard from several Stakeholders who spoke to a range of issues such as the different types of new gas customers and their unique and sometimes contrasting needs when it comes to making an efficient energy choice, the challenges faced by off-system communities in meeting their specific energy needs, and a comparison and discussion of the system extension policies of other utilities in Canada and the Pacific Northwest.

A key finding from the workshop was a general consensus among stakeholders that there are gaps in FortisBC's system extension policies in terms of addressing the needs of the different types of customers. Another key finding was the support of a consultative, efficient process for the review of a potential, future application. FortisBC and other stakeholders, including CEC and PIAC, reported how the process followed in 2011 for FortisBC's Gas Supply Incentive and Mitigation Program ("GSMIP") was effective and could serve as a model for engaging stakeholders and pursuing an application with the British Columbia Utility Commission (Commission). In light of these findings, participants agreed to continue with a consultative review of the Company's system extension policies resembling the GSMIP process.

On June 18, 2014, FortisBC held a second system extension stakeholder workshop. Prior to this meeting, FortisBC sent a stakeholder package for comments to help guide the discussion. The purpose of this meeting was to summarize the first workshop, review the terms of reference, and discuss the guiding principles for system extension policies and the deliverables following the workshop.

A list of workshop attendees is found in Appendix A.

Throughout the second workshop, FortisBC summarized feedback it received from stakeholders in advance of the workshop and facilitated the expression of a wide variety of interests. The document that follows captures the views expressed in the second workshop.

PART 3: PROJECT TERMS OF REFERENCE

The following section outlines the terms of reference for the Project, specifically, the purpose, process, roles and responsibilities, scope and timelines.

Purpose

This Project is a stakeholder driven initiative designed to address gaps with FortisBC's current natural gas system extension policies.

Process

The Project workshops will provide a venue to educate stakeholders and solicit their feedback on FortisBC's system extension policies. Recommendations from the Project will form the foundation for a potential application from FortisBC to the Commission. By employing a stakeholder focused approach, the varied interests of stakeholders will be best represented and the Project is expected to be more efficient as a result.

As discussed above, FortisBC is trying to replicate the process used to develop the GSMIP.

Roles and Responsibilities

In the Project, there are four Project roles for participants: facilitator, consultant, stakeholder and Commission Staff.

Facilitator

This role will be fulfilled by FortisBC. In summary, the function of the facilitator is twofold: a) to oversee the manner in which the Project process is carried out; and b) to ensure that the full range of issues is effectively addressed. In conducting the Project, the facilitator will:

- Help to foster an environment of cooperation and trust among participants
- Ensure that all participants have an opportunity to express their views on each issue
- Facilitate the preparation of a proposed Project application which contains all the required components
- Guide the list of issues

The facilitator will attempt to perform the following functions:

- clarifying and summarizing a party's position;
- making explicit any differences in the positions taken by the respective parties;
- recognizing the possible concerns of unrepresented parties;
- encouraging a party to evaluate its own position in relation to other parties by introducing objective standards; and
- identifying options or approaches that have not yet been considered

In the event that FortisBC proceeds with an application to the Commission, FortisBC will be seeking letters of comment and/or support from stakeholders who attended the workshops.

Consultant

This role will be fulfilled by EES Consulting who will provide expertise in the area of system extension policies and related analysis.

Stakeholder

This role will be fulfilled by all parties other than FortisBC, EES Consulting and Commission Staff. Stakeholders have a right to participate in the Project. The responsibilities of this role are as follows:

- Attend workshops and participate in all aspects of policy exploration and formulation
- Represent the views of their constituents
- Review and comment on data analysis and results as needed

Commission Staff

The responsibility of Staff is to ensure that the interests of all affected parties are taken into account. The responsibilities of Staff involved in the Project include the following:

- Supplying factual information that may otherwise not have been brought to the attention of the stakeholders
- Describing possible implications of Project proposals for unrepresented parties; and
- Advising the participants of any precedents recognized by the Commission;

Scope

Included in the Project scope generally is the Companies' current system extension policies and the development of a suitable construct (s) to attach customers, including but not limited to the following:

Customer Types	Description of Customer Type	Current Regulatory Construct	Scope of System Extension Review*
Infill	Customers located within the Companies distribution service territory that requires a service connection to existing natural gas infrastructure already at their location.	Service line cost allowance ("SLCA")	• Identifying a construct to attach infill customers
Main extension ("MX")	Customers who are within a local proximity to the Company's current distribution system and require a main extension to their location before a service connection can be provided.	MX test	• Identifying a construct to attach main extension customers
Off system communities, including First Nations	Customers who require, but do not currently have any natural gas distribution infrastructure within their community.	Certificate of Public Convenience and Necessity ("CPCN")	• Identifying a construct to attach off-system

* Commonalities in the scope of the review across different customer types are as follows:

Time horizon

- Time horizon of any economic test developed
- Forecasting period for new customer attachments

Rate Class

- Treatment of individual customer classes based on rates

Uneconomic Customers

- Contribution in aid of construction (“CIAC”) financing
- Contributory thresholds
- Security

Reporting

- Best practices of other peer utilities
- Review of FortisBC’s current reporting practices & performance results
- After the attachment model is agreed upon, recommend reporting construct if required.

Timeline

The Project timeline is summarized in the table below:

Date	Event	Topic	Goal	Status
Q4 2013	Individual Stakeholder Consultation	Initial Consultation	Garner Stakeholder support to begin review process.	Complete
February 18, 2014	FortisBC System Extension Stakeholder Workshop #1	Policy Issues	Introduction to current issues and agreement to proceed with exploration of policy alternatives.	Complete
June 18, 2014	FortisBC System Extension Stakeholder Workshop #2	Review of Workshop 1, Terms of Reference & Guiding Principles	Stakeholder feedback on guiding principles will be used to form the foundation of policy options.	Complete
October 2014	FortisBC System Extension Stakeholder Workshop #3	Options Discussion	Review system extension options as developed by Fortis and Stakeholders and opportunity for questions and changes.	TBD
November 2014	FortisBC System Extension Stakeholder Workshop #4	Options Discussion	Continuation of Workshop 3 (as needed)	TBD
Q1 2015	Potential Application	Potential Application	Consideration of potential application to Commission	TBD

PART 4: GUIDING PRINCIPLES

This section is intended to form the initial policy foundation for any future system extension policy enhancements to be considered in the Project. It is organized into three sections covering the following:

- The background on relevant guiding principles from historical Commission proceedings
- The change in market conditions since the most recent Commission proceedings
- Summary of stakeholder feedback on guiding principles

Background

1996 Utility System Extension Test Guidelines

This following list briefly summarizes some of the voluntary guidelines[1] that were developed and issued by the Commission under order G-80-96[2] following a hearing and reconsideration decision on Utility System Extension Tests during the late 1990's.

- Evaluation of system extension should include all benefits and costs over a time period long enough to consider the full impact of the extension.
- System extensions should be evaluated from a social perspective and a utility perspective.
- System extension costs should include pre-construction estimates of the construction costs, system improvement costs, O&M costs, revenues and a reasonable consideration of externalities (for the social perspective evaluation.)
- Utilities should come forward with options for connection fees that send an appropriate signal about the net social costs of less efficient energy use.

2007 Terasen Utilities System Extension and Customer Connection Policies Review Application[3]

The items below highlight some of the key considerations Terasen (now FortisBC) put forward as the basis for the modifications requested in the application. The Companies stated that system extension policies should:

- Signal better value for customers wishing to attach to the system.
- Measure the right factors, be simple to understand and administer with results that send the appropriate economic signal to the customer.

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[1] 1996 Utility System Extension Test Guidelines – September 5, 1996.
[2] British Columbia Utilities Commission Order G-80-96 – August 9, 1996.
[3] Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. System Extension and Customer Connection Policies Review Application - July 31, 2007.

- Encourage energy conservation through the test and attachment policies
- Encourage the "right fuel" choice. The Companies believe that natural gas is the appropriate fuel for space and water heating applications and that the connection policies and tests should send the appropriate signal to customers for these energy choices.

The Companies' proposed modifications to its system extension policies were approved under Commission Order G-152-07[4].

Bonbright Principles

The following list of principles has been developed by FortisBC by incorporating system extension issues in the context of the Principles of Public Utility Rates, developed by James C. Bonbright. (Bonbright Principles). Bonbright Principles have been referred to in various applications by the Companies and other utilities. As such, they help by providing a framework for discussing future system extension policy considerations.

• Customer Impact	Considers customer rate impacts of system extensions.
• Fairness:	Ensure fairness between customers in terms of both cost causation and similar treatment over time, recognizing the changes in housing environment, technology and natural gas usage patterns of new and existing customers. Also recognizes the need for fair access for "off-system" communities who require natural gas service.
• Economic Efficiency	Recognizes energy efficiency and conservation at the time of construction for new connections and in the trade-off between main extension policies and rate impacts.
• Stability:	Reflects long-term objectives that will not lead to frequent changes so that customers know what to expect over time.
• Ease of Understandability:	Allows customers to understand the policies and therefore be able to make appropriate choices, as well as making policies easy to administer.

[4] British Columbia Utilities Commission Order G-152-07 – December 6, 2007

- Competitiveness: Allows for competitiveness of the utility to attract new customers relative to competing gas utilities as well as competing alternative fuels.
- Recovering the Cost of Service: Allows for recovery of utility costs.

Changing Market Conditions

The marketplace has undergone several significant changes since the mid-1990s when system guidelines were developed. These changes and the resulting policy considerations follow.

Natural Gas Supply

Since the time of the development of the original utility system extension guidelines by the Commission in 1996, and a review of system extension policies in 2007, the BC natural gas industry as a whole has undergone substantial change. Supply outlooks reversed from an imminent dwindling of supplies and a scramble to find and import LNG, to today, where BC has now become a leading exporter of natural gas to Canada, the US and global markets with supplies forecast beyond the next 100 years[5]. Prices have gone from a high and volatile to a low and relatively stable environment.

Provincial Government Objectives

During the second workshop, two provincial government objectives were identified:

1. *Environmental considerations related to the Greenhouse Gas Reduction Target Act and the Clean Energy Act*
2. *Economic considerations related to the province's natural gas strategy*

Stakeholders identified challenges in accommodating both objectives in the context of a review of FortisBC's system extension policies. Promoting the most efficient use of natural gas was brought forward as a potential common ground for the two government objectives.

Amalgamation & Rate Design

Stakeholders identified the importance of acknowledging FortisBC moving to a "postage stamp" rate in 2015 and a potential rate design proceeding in 2016. FortisBC indicated that it hoped to proceed with a potential application related to the Project before rate design proceeding occurs.

1.1.1 Guiding Principles

In the second workshop, stakeholders discussed the need for tradeoffs when considering guiding principles as some principles are complimentary while others are contradictory. The

5 Spectra Energy presentation at PNUCC Power and Natural Gas Planning Taskforce meeting April 11, 2014

following section summarizes the feedback received during the workshop into several main categories.

Protecting Ratepayers

- Relevant benefits, costs and rate impacts of system extension policies should be considered as they relate to new and existing customers

Provide an Energy Choice

- System extension policies need to consider the need for BC residents to fairly and equitably access a variety of energy options.

Consistency with Government Objectives

- System extension policies relating to the domestic use of natural gas need to be consistent with the provincial government's natural gas strategy
- The provincial government's environmental and economic objectives also need to be considered

Recognize First Nations

- The needs of First Nations communities should be recognized

Easy to Understand

The system extension policies need to be easily understood, easy to administer by FortisBC and stable over time for customers

Appendix

Below is a list of FortisBC employees, stakeholders and Staff who participated in the first and second workshops.

Stakeholder	Attendee	Title	Attended Workshop 1	Attended Workshop 2
BC Hydro	**Justin Miedema**	Senior Regulatory Advisor, Rates and Regulatory	**Yes**	**Yes**
BC Hydro	**Kevin Lim-Kong**	Policy Specialist, Customer Interconnections & Policy	**Yes**	**n/a**
BC Hydro	**Frank Lin**	Director, Interconnections and Shared Assets	**Yes**	**n/a**
BC Hydro	**Rena Messerschmidt**	Policy Manager, Customers Interconnections & Policy	**Yes**	**n/a**

Stakeholder	Attendee	Title	Attended Workshop 1	Attended Workshop 2
BC Chamber of Commerce	**Susan Payne**	Executive Director, Ucluelet Chamber of Commerce	**n/a**	**Yes**
BCUC - British Columbia Utilities Commission	**Kristine Bienert**	Acting Director, Policy, Planning and Customer Relations	**No**	**No**
BCUC - British Columbia Utilities Commission	**J Todd Smith**	Acting Director, Infrastructure	**No**	**No**
BCUC - British Columbia Utilities Commission	**Suzanne Sue**	Senior Regulatory Specialist	**Yes**	**Yes**
BCUC - British Columbia Utilities Commission	**Chris Garand**	Engineer, Infrastructure	**Yes**	**Yes**
Chawathil First Nation	**Norman Florence**	Council Member	**n/a**	**Yes**
CEC - Commercial Energy Consumers	**David Craig**	President, Consolidated Management Consultants	**Yes**	**Yes**
EES	**Gail Tabone**	Senior Consultant, EES Consulting	**Yes**	**Yes**
Fortis BC	**Mike Metza**	Energy Products & Services Manager	**Yes**	**Yes**
Fortis BC	**Brent Graham**	Manager, Energy Products & Services	**Yes**	**Yes**
Fortis BC	**Jason Wolfe**	Director, Market Development	**Yes**	**Yes**
Fortis BC	**Dennis Swanson**	Director, Regulatory Affairs	**Yes**	**Yes**
Fortis BC	**Vanessa Connolly**	Government Relations and Public Affairs Manager	**n/a**	**Yes**
Fortis BC	**John Turner**	Director, Energy Solutions	**Yes**	**n/a**

Stakeholder	Attendee	Title	Attended Workshop 1	Attended Workshop 2
Fraser Valley Regional District	**Lloyd Foreman**	Director, Electoral Area A	**n/a**	**Yes**
Fraser Valley Regional District	**Dennis Adamson**	Director, Electoral Area B	**n/a**	**Yes**
MEM - Ministry of Energy and Mines	**Katherine Muncaster**	Acting Director, Energy Efficiency Branch	**Yes**	**Yes**
MJT - Ministry of Jobs, Tourism and Skills Training	**Robert Wood**	Acting Director, Major Investments Office	**n/a**	**Yes**
MLA Boundary - Similkameen	**Colleen Misner**	Constituency Assistant to Linda Larson, MLA	**Yes**	**No (illness)**
Okanagan - Similkameen Regional District	**George Bush**	Board Member	**Yes**	**Yes**
PRRD - Peace River Regional District	**Karen Goodings**	Board Director	**Yes**	**Yes**
PIAC - Public Interest Advocacy Centre	**Tannis Braithwaite**	Executive Director	**Yes**	**Yes**
PNG - Pacific Northern Gas	**Janet Kennedy**	Vice President, Regulatory Affairs and Gas Supply	**Yes**	**Yes**
PNG - Pacific Northern Gas	**Peter Schriber**	Manager, Financial Planning & Business Development	**Yes**	**Yes**
Seabird Island Band	**Brian Titus**	Consultant	**n/a**	**Yes**
Seabird Island Band	**Chief Clem Seymour**	Chief	**n/a**	**Yes**
Yale First Nation	**Steven Patterson**	Natural Resource Manager	**n/a**	**Yes**

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Appendix C
SYSTEM EXTENSION TEST INPUTS TABLE

Forecasted Test Input	*Information Source*	*Explanation*	*Current System Extension Test Rules*	*System Extension Test Result*	*Ratepayer Protection*	*Real-World Comparison*
Number of Attachments	External The builder or developer associated with the project.	Build out plans, civil drawings and registered lot drawings form the basis for the number of attachments. In general, the Company does not "create" the attachment forecast. These drawings are the same ones that would be sent to other utilities and local municipalities. Similar to all other utilities such as hydro and water, it is very difficult for the Company to go into a development after the fact and connect individual homes with natural gas. Therefore the Company must rely on information provided by the builder or developer to install before construction, similar to all other utilities.	Only attachments that occur within the first 5 years can be considered in the test	Understates Benefits	Increased protection for Rate Payer	Attachments can continue to occur on system extensions well beyond the first 5 years and in many cases the system extension test does not capture full scope of a project.
Timing of Attachments	External A function of the economy, predicted by the builder	As stated above, the Company and other utilities rely on information from the customer to define the scope of the project and number of connections. This includes plans as to when an attachment will occur. Any forecast in this regard is difficult to predict given that neither the builder, nor the Company can say they know exactly when a home will be planned, constructed, sold, a customer moved in and finally when that customer choses to call Fortis to activate their meter. All of the unknowns above are also impacted by the housing market and economy which in turn impacts the timing of attachments.	Based on a forecast and project plan provided by the builder, developer or customer.	Neutral	Neutral	Since the test only considers attachments within the first five years and only considers the revenue from those attachments for less than half of their economic life, a discrepancy in the timing of that attachment has no material impact in the real world.
Costs	Internal Known as "geo pricing"	The Company runs annual statistical analysis of regional costs for system extensions and includes dollar per meter values for specific regions. In addition, if a planning and design expert feels that there is a potential for costs to be understated, they have the ability to change the values to more accurately reflect costs.	All costs are included in the test including the main, service meter and regulator	Neutral	Neutral	In some cases a system extension may have higher actual costs and in other cases the costs may be lower. This is a result of the fact that the Company cannot predict exactly what will be found underground or what complication will occur during construction. Overall the aggregate cost variances in the system extension report are around 10%.
Economic Life Span	Policy Fixed as part of the Test	The current system extension test considers revenue and costs over the first 20 years of a new extension.	The economic life-span is fixed for all customers	Understates Benefits	Increased protection for Rate Payer	A system extension has an economic life of 50 years. As such, the current system extension tests considers less than half of the benefits a new customer would bring to the system.

Forecasted Test Input	***Information Source***	***Explanation***	***Current System Extension Test Rules***	***System Extension Test Result***	***Ratepayer Protection***	***Real-World Comparison***
Rates	Internal Fixed	Rate inputs are updated annually. However they remain static within the 20 years the test considers.	Rates are fixed for each of the 20 years included in the test	Understates Benefits	Increased protection for Rate Payer	Rates generally increase over time. The current test assumes all rates remain static for 20 years and therefore the revenue from a new customer is understated. Furthermore, the test does not consider the positive impacts an additional ratepayer brings by expanding rate base and spreading costs over a larger portion of ratepayers.
Use per Customer	Policy Fixed (residential)	For residential customers the use per customer is a function of the appliances they install. The use per customer is calculated based on an average for each appliance. These values have remained static since 2008 and are based on an average of all existing customers.	Fixed for residential based on appliance installations	Neutral	Neutral	Since new appliances are much more energy efficient, by nature they consume less gas. As a result, the Company's forecasts which are based on an average of all customers will always be different than the actual consumption of new customers who have much more efficient homes and appliances. The FEU have always used the most up to date information possible to determine the average consumption for existing customers via the Residential End Use Study, as approved by Commission Staff.
	Variable (Commercial and Industrial)	Commercial and Industrial customers are sized according to their specific needs. The proper consumption information is usually provided by their mechanical engineer or gas fitter who must ensure that the pressure, meter size and service diameter are designed to specifications.	Variable for Commercial and Industrial based on specific needs.	Neutral	Neutral	

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BRITISH COLUMBIA UTILITIES COMMISSION

LETTER L-32-13

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VIA EMAIL
gas.regulatory.affairs@fortisbc.com

June 5, 2013

Ms. Diane Roy
Director, Regulatory Affairs – Gas
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Ms. Roy:

Re: FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc.
Compliance Filings of the 2012 FEI and FEVI
Main Extension and FEI Vertical Subdivision Reports

The British Columbia Utilities Commission (Commission) acknowledges receipt of the following compliance filing submitted by FortisBC Energy Inc. (FEI) and FortisBC Energy (Vancouver Island) Inc. (FEVI) (collectively, the Companies):

Filing	**BCUC Compliance**	**Date Received** (YYYY/MM/DD)	**Anticipated Filing Date** (YYYY/MM/DD)
2012 FEI and FEVI Main Extension and FEI Vertical Subdivision Reports (2012 MX Report)	Order G-152-07 Order G-6-08 Letter L-67-11 Letter L-19-12 Letter L-60-12	2013/03/28	2013/03/31

The Commission reviewed the 2012 MX Report and considers the MX results reporting to be generally compliant with the reporting requirements set out in the above referenced Commission Orders and Letters. The Commission finds the table formats in the 2012 MX Report, with the original forecast and actual performance reporting, to be informative. However, as actual attachments and consumption show unfavourable variances through the MX reporting period, certain MX installations continue to fall short of the minimum Profitability Index (PI) thresholds.

In Letter L-60-12, the Commission requested the Companies to include three items in this annual MX report for clarity and completeness. The Commission finds that the Companies provided one of the three requested items. The Commission is satisfied with the first item of original forecast and actual results reporting for consumption and use per customer on a per year basis. The Commission is also satisfied with the data tables segmented by rate class to include forecast and actual results of attachments, consumption, and use per customer on a go-forward basis beginning in 2012.

With respect to the PI reporting requirements, the Companies in response to Letter L-60-12 submitted a report by EES Consulting (EES Report) as Appendix C to the 2012 MX Report; the EES Report suggests possible alternatives to the existing MX Test. The Commission is mindful that Order G-152-07 and its accompanying 2007 Decision directs the Companies to "determine if the aggregate PI [Profitability Index] thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1." The Companies are expected to use the existing MX Test as established by Order G-152-07 to meet this directive, and since the EES Report does not do this, it does not fulfill the requirements of the PI reporting directive; the Commission makes no determination on the EES Report itself at this time. A separate process to review the MX Test and MX historical results is required to vary the MX Test methodology and its reporting requirements.

With respect to accounting for MX ramp-up, the Commission is dissatisfied with the continued lack of ramp-up factor for a number of MX projects, despite instructions in L-67-11 to report ramp-up in all new main extensions. While the Companies indicate intent to base all future MX calculations on a minimum 80 percent ramp-up factor, this does not absolve them of the requirement to have been doing so in past years as well. The Commission is also concerned that the Companies have not justified a basis for the selection of 80 percent as a minimum ramp-up factor. This continues to leave the Companies vulnerable to connection requests from potentially-underperforming developments based on unverifiable data provided from developers that may have a financial incentive to overestimate consumption in the interests of avoiding a contribution in aid of construction.

Due to the Companies' continued problems with the PI of their main extension portfolios, and the areas of non-compliance identified in this letter, the Commission intends to initiate a separate process to review the System Extension and Customer Connection Policy. Additional information will be provided in due course. In the meantime, if you have any questions, please contact Ian Dawkins at 604 660 5664.

Yours truly,

Erica Hamilton

ID/nd

Diane Roy
Director, Regulatory Affairs

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June 26, 2013

Via Email
Original via Mail

British Columbia Utilities Commission
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V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI) and FortisBC Energy (Vancouver Island) Inc. (FEVI)

2012 Year End Report for FEI-FEVI Main Extension (MX) Report – British Columbia Utilities Commission (the Commission) Order No. G-152-07[1] Compliance Filing; and FEI Vertical Subdivision Report – Commission Order No. G-6-08 Compliance Filing (the 2012 MX Report)

FEI-FEVI Response to Commission Letter L-32-13

FEI and FEVI (collectively the Companies) are writing in response to Commission Letter L-32-13 (the Letter) dated June 5, 2013. The Companies disagree with the Letter's characterization that there were "areas of non-compliance"[2] with respect to the Companies' 2012 MX Report. In the Companies' view, the 2012 MX Report fully complies with the Commission's MX reporting requirements established in the two Commissions orders (G-152-07 and G-6-08), interpreted by subsequent letters. In particular, the Companies believe that its 2012 MX Report meets the profitability index (PI) and MX ramp-up reporting requirements, as more fully explained below. Additionally, the Commission's compliance concern over the 2012 MX Report and the Companies' request for a review of the system extension policies are two separate issues and should be treated as such.

The Companies accordingly respectfully request that the Commission issue a letter confirming that the Companies 2012 MX Report is in full compliance with the relevant Commission orders.

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[1] Decision and Order G-152-07 dated December 6, 2007, in the matter of FEI-FEVI (then Terasen Gas) System Extension and Customer Connection Policies Review.
[2] Page 2.

2012 MX Report

First, the Companies wish to stress that meeting each and every one of their compliance directives from the Commission is of great importance. When preparing the 2012 MX Report, the Companies have striven for, and have taken reasonable steps to achieve, full compliance with Commission orders. Appendix A to this letter provides a brief review of the recent history of how the Companies have worked to achieve compliance with Commission MX reporting requirements, including having numerous communications with Commission staff.

In summary, the 2012 MX Report represents not only the Companies' own analysis and understanding of the two Commission's orders establishing MX reporting requirements, but is also a culmination of multiple phone and email correspondence with Commission staff and two in-person meetings with Commission staff. The 2012 MX Report also fully reflects the previously approved 2011 MX Report format and methodologies, and contains the improvements that have been specifically identified in the Commission's Letter L-60-12. Furthermore, the Companies prepared the 2012 MX Report by closely following a format previously agreed upon with Commission staff.

Explanation of Companies' Compliance with PI and Ramp-Up Reporting Requirements

Letter L-32-13 states that the 2012 MX report is "generally compliant with the reporting requirements" established in the two relevant Commission orders and subsequent clarifying letters. However, the Letter identified two areas of "non-compliance": (1) PI reporting, and (2) MX ramp-up accounting. The Companies disagree with this view, and will address their compliance with the Commission's requirements regarding these two aspects respectively below.

1. PI Reporting:

In Order G-152-07 and its accompanying Decision, the Commission required that the Companies file their annual MX Report to include:

> *"a review of a random sampling of MX test results representing a confidence interval of +/-12 percent at a 95 percent confidence level and the five highest cost main extensions to determine if the aggregate PI thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1. The review is to include a comparison of forecast and actual costs; consumption; and PI for the first five years of main extensions in the sample."* (page 37)

Letter L-60-12 asks for the following information from the Companies "for clarity and completeness":

> *"Order G-152-07 and its accompanying 2007 Decision directs the Companies to "determine if the aggregate PI [Profitability Index] thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1." The re-calculated PI*

> *with actual data for both FEI and FEVI in 2010, 2009 and 2008 indicate aggregate PI values below 1.1. The Companies should include a plan to address and comply with the above noted directive for each utility and for each reporting cohort year."* (page 2)

Letter L-32-13 expresses no concern about the random sampling or the comparison of forecast and actual costs, consumption, and PI for the first five years of main extensions in the sample as contained in the 2012 MX Report. Rather, the Letter asserts that the report by EES Consulting (the EES Report) submitted by the Companies in response to Letter L-60-12 was insufficient to meet the PI reporting requirement.

With respect, the Companies disagree with this assertion. The Companies submitted the EES Report to specifically comply with the direction to include "a plan". To provide a plan that addresses the appropriate PI threshold level on a go-forward basis requires the Companies to review the existing MX test and policies as a whole. This is a complex task as the Companies need to consider multiple issues, including the interests of the existing and future customers, the impacts of technology and efficiency, changes to the economic and housing market environments, the tests of other jurisdictions, and intergenerational equity among new and existing customers. As such, the Companies engaged recognized experts in system extension policy (i.e. EES Consulting) to conduct a thorough review, including the PI threshold.

The Companies' "plan" provides more than just a potential adjustment to the low PIs as, found by the EES Report, the low PIs are a symptom of larger issues with the Companies' system extension policies. Thus, the EES Report provides a framework for an examination of several components of the Companies' system extension policy, as shown in Appendix C to the 2012 MX Report. Further,

- The Companies believe that the current reporting practices do not adequately reflect the results of the Companies' system extension portfolio. For instance, as discussed in section 3 of the 2012 MX Report, the PI results reflect a snapshot in time and are not indicative of the overall impact of a main extension on existing ratepayers. The overall impact can only be determined after the useful life of the asset is reached at 40 to 50 years. Therefore, the reported PI for any given year is only a directional indicator, nothing more.

- As a directional indicator, the PIs in the 2012 MX Report do show the effect of lower consumption from new customers as compared to existing customers. While only directional at this point, this variance is, in part, driving the desire of the Companies to review their system extension policies.

The Companies recognize that there seems to be some confusion in the 2012 MX Report in terms of the Companies' view on whether the PI threshold needs to be adjusted on a go-forward basis. This may have prompted the statement in the Letter that "[a] separate process to review the MX Test and MX historical results is required to vary the MX Test methodology and its reporting requirements." **The Companies believe that the current existing PI threshold of the aggregate main extensions and the minimum PI for individual PIs, should remain until such time as a new system extension and customer connection application is filed by the Companies and approved by the Commission.**

2. Accounting for Ramp-Up

Letter L-32-13 also expresses "dissatisfaction" with the Companies' accounting for the ramp-up factor for a number of MX projects as follows:

> *"While the Companies indicate intent to base all future MX calculations on minimum 80 percent ramp-up factor, this does not absolve them of the requirement to have been doing so in past years as well. The Commission is also concerned that the Companies have not justified a basis for the selection of 80 percent as a minimum ramp-up factor."* (page 2)

The following discussion shows, however, that the Companies have complied with the relevant reporting requirements of reporting their ramp-up experience.

In Order G-152-07, the Commission directed the Companies "to reflect in the Companies' MX tests their experience of consumption "ramp-up" in the early months of service." As the Commission acknowledged in Letter L-60-12, the Companies did include in the 2011 MX Report ramp-up factors in each of the Top 5 MXs to reflect the Companies' experience. However, the Commission was uncertain "whether the Companies expect no consumption ramp-up or have not conducted any ramp up analysis at the time of MX construction" because the ramp-up factor for most Top 5 MXs was reported as zero. Thus, Letter L-60-12 requests that ramp-up be "clearly explained for each of the Top 5 MXs by comparing the original forecast ramp-up adjustment factor to the actual consumption ramp-up results." Additionally, Letter L-60-12 also states that, "[c]onsumption ramp-up experience by rate class would provide more informative reporting."

Letter L-32-13 seems to suggest that the "dissatisfaction" specifically came from a lack of having a specific value for the ramp-up factor in the Companies' MX Test calculation. First, the Companies note that neither Order G-152-07 nor Order G-6-08 specifies a value for the ramp-up factor. As suggested by Letter L-60-12, a Commission letter does not and cannot, impose additional MX reporting requirements; rather, the information sought in the letter is for clarity or for soliciting further explanation or examples within the scope of the original orders.

Like the 2011 MX report, all Top 5 MX tables in the 2012 MX Report contain a specific ramp-up factor. In many cases this factor is zero, which means that the first year consumption of the attachment(s) was not reduced and was expected to remain at 100 percent of the forecasted annual consumption. In addition, the reporting of the Companies' ramp-up experience is implicit in the first year consumption reporting for all reporting tables. **Thus, in compliance with Commission orders, the Companies have reported their experience of consumption "ramp-up."** As noted on page 5 of the 2012 MX Report, the Companies have further explained that the ramp-up is implemented on a project-by-project basis only. Due to the difficulties in forecasting to such a granular level, the Companies cannot conduct individual ramp-up analysis at the rate class or attachment level.

The "dissatisfaction" may result from a different understanding of "ramp up" factor and its effect on the overall PI. Once a building is constructed and gas service attached, there will likely be no consumption until a customer moves in and establishes an account. At that point consumption goes from zero to a level that is consistent with the demand of appliances in the building. Thus, there is no “ramp up” in consumption; rather, “ramp-up” is a timing issue, which addresses when a customer is expected to begin to consume gas. Consumption in the first year can be adjusted to reflect the point at which the consumer is expected to begin using gas, which results in usage that is a percentage of a normal full year usage. For example, an 80 percent “ramp-up” factor means that the first year of consumption for a given customer would be reduced based on an understanding that they will use 80 percent of the expected annual consumption. In other words, the customer would connect to the system 2/10ths of the way through the year. The remaining nineteen out of twenty years of the life of the project would not reduce the expected annual consumption.

The Companies have implemented a default ramp-up factor of 80 percent to adjust the first year consumption used in the Companies planning and design software on a go-forward basis. This value cannot be increased without the approval of a Planning and Design Manager. The Project Managers and Planners do have the discretion to further reduce the ramp-up factor if they have knowledge that would indicate a customer would not connect to the system until a later time within the first year of the life of the main, thus ensuring a more conservative system extension test.

It should be noted that the impact of first year consumption adjusted from 100 percent to 80 percent or a lower number is relatively small on the PI calculation due to the 20 year nature of the test.

The Companies believe that they have complied with Order G-152-07 and Order G-6-08 and have offered further explanations and clarifications as specified by Letter L-60-12 regarding ramp up as part of their annual MX Report.

FUTURE REVIEW OF MX TEST

On page 8 of the 2012 MX Report, the Companies requested a review of the existing system extension and customer connection policies. In Letter L-32-13, the Commission expressed its intention to conduct such a review. Concurrently, the Companies are undertaking steps to review the MX test and existing policies. If the Companies believe that changes are required, the Companies will file an application seeking Commission’s approval. Similarly, if the Commission believes that the test is not meeting the Companies’, or the customers’, needs, it can direct the Companies to undertake a review.

However, the issue of the Companies’ compliance with current existing policies and the need for a review are distinct. The Companies believe that they have complied with all MX reporting requirements as laid out in the Commission orders and as clarified by subsequent letters. The issue of compliance is separate from a need to review the system extension test. Indeed, as detailed above and in Appendix A, **the Companies have taken reasonable steps to achieve compliance, and are in compliance with all of the Commission’s system extension reporting requirements.**

Conclusion

Accordingly, the Companies respectfully request that the Commission issue a letter confirming that the Companies are fully compliant with the relevant MX reporting orders.

If further information is required, please contact Mike Metza at (604) 592-7852.

Sincerely,

FORTISBC ENERGY INC. AND
FORTISBC ENERGY (VANCOUVER ISLAND) INC.

Original signed by: Stan Crocker

For: Diane Roy

Attachment

Appendix A – Recent History of MX Compliance

Introduction

Compliance with applicable law, regulation, orders, and directives of the Commission in the Companies' operation is of great importance to the Companies as it will help ensure safe and reliable delivery of services.

This Appendix will show that the Companies have taken all reasonable steps when preparing the 2012 MX Report, including working with Commission staff, to ensure that the Commission's MX reporting requirements set forth in Orders G-152-07 and G-6-08 are met. The 2012 MX Report also follows the same format as the 2011 MX Report that was agreed upon with Commission staff and subsequently accepted as generally compliant by the Commission. Further, the 2012 MX Report contains the three enhancements outlined in Letter L-60-12.

2011 MX Report

On July 31, 2012, the Companies filed the 2011 FEI and FEVI Year End Main Extension Report which adhered to the Commission data requests, format and methodologies that were agreed to in previous meetings and discussions with Commission staff while continuing to comply with the requirements in Orders G-152-07 and G-6-08.

On October 16, 2012, in response to the 2011 MX Report, the Commission issued letter No. L-60-12, which stated that that report was "generally in compliance with the reporting requirements set out in Order G-152-07 and its accompanying 2007 Decision, Order G-6-08, and as clarified in Letters L-67-11 and L-19-12." In Letter L-60-12, the Commission also identified three enhancements that were to be included in the 2012 MX Report to improve the clarity and completeness of the Report.

2012 MX Report

The Companies submitted the 2012 Report on March 28, 2013. The 2012 MX Report essentially followed the same format as the 2011 Report. That report was a result of lengthy consultation with Commission staff, was agreed upon by Commission staff, and was subsequently accepted to be in general compliance by the Commission. The only substantive changes to the 2012 MX Report were the result of the Companies incorporating feedback from Commission staff about the expectations related to the three suggested enhancements provided in Letter L-60-12.

The table below provides a description of the reporting requirements from Commission orders and subsequent clarifications and enhancements asked by Commission letters and the Companies' reporting responses. It should be noted that the table is derived from data included in the 2011 and 2012 MX Reports and provides a summary of the applicable reporting requirements established in Orders G-152-07 and G-6-08 and subsequent clarifying Letter L-60-12 and the Companies' corresponding reporting compliance.[1,2]

[1] FEI-FEVI Main Extension Reports for 2011 Year End, submitted on July 31, 2012 – Section 1, p.10.
[2] FEI-FEVI Main Extension Reports for 2012 Year End, submitted on March 28, 2013 – Section 2, p.5.

Appendix A – Recent History of MX Compliance

Compliance Asks	*Order or Letter Reference*	Reporting Compliance
Report Methodology – Random Sample Reporting	*Order Nos. G-152-07 and G-6-08, and Letter L-19-12 p.2*	The Companies have utilized the random sample methodology established in Order Nos. G-152-07 and G-6-08
Reforecasting Methodology Update	*Letter L-19-12 p.2*	The re-forecasted P.I. value has been updated to use actual data when available and original forecasts (from the original/initial MX Test) for future years as agreed upon with Commission staff.
S.I. Charge Explanation and Update	*L-67-11 p.3*	The S.I. Charge will now be updated on annually on a go-forward basis, with an updated value and detailed explanation already provided in the 2012 MX Report on p.15.
"Ramp-Up" Factors for Top 5 MX	*L-67-11 p.3*	A "Ramp-Up" factors column has been provided and populated for all Top 5 Cost MX Tables in both the 2011 and 2012 MX Report.
MX Report Data Tables	*Email*	MX report tables established through discussion and email correspondence with Commission staff have been completed and integrated into the MX Report process and format. Commission staff provided raw tables (designed and formatted) to be populated with MX data to be provided by the Companies. These tables are now present in the 2011 and 2012 MX Reports and will be present in all future MX Reports.
Consumption and Use Per Customer	*Letter L-60-12 p.1*	All tables in the 2012 MX report and future reports have been updated to reflect an annual consumption and use per customer breakdown as requested by staff.
Table Segmentation by Rate Class	*Letter L-60-12 p.1*	Given the complexity and resources required to gather this type of data, this change has been implemented on a go-forward basis. All new data tables including the 2012 cohort of mains now reflect segmentation by rate class.
Ramp-Up Explanation	*Letter-L-60-12 p.2*	As described on page 5 of the 2012 MX Report past practice has been to apply Ramp-Up on a per project basis at the planner's discretion. For those projects that show a Ramp-Up factor of zero, a decision would have been made by the planner not to apply a Ramp-Up factor. On a go-forward basis, the Companies will provide an explanation where applicable. Also, to assist in ensuring a highly conservative Main Extension Test the Company has recently completed a new IT enhancement whereby all main extension projects will default to a minimum Ramp-Up value of at least 80 percent. This process was put in place on March 1st, 2013.
Consumption Ramp-Up experience by rate class.	*Letter L-60-12 p.2*	Ramp-Up is implemented on a per project basis only. Due to the difficulties in forecasting to such a granular level, the Companies do not conduct individual Ramp-Up analysis at the rate class or attachment level as such the Companies do not have data to provide.
Plan to address low aggregate PI thresholds on a go-forward basis.	*Letter L-60-12 p.2*	Provided as Appendix C in the 2012 MX Report and titled FortisBC Energy Utilities Review of System Extension Policies. (Prepared by EES Consulting)

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VIA EMAIL
gas.regulatory.affairs@fortisbc.com

July 8, 2013

Ms. Diane Roy
Director, Regulatory Affairs - Gas
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N OE8

Dear Ms. Roy:

Re: FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc.
Compliance Filings of the 2012 FEI and FEVI
Main Extension and FEI Vertical Subdivision Reports

The British Columbia Utilities Commission (Commission) acknowledges receipt of your letter dated June 26, 2013, in which FortisBC Energy Inc. (FEI) and FortisBC Energy (Vancouver Island) Inc. (FEVI) (collectively, the Companies) requests that the Commission "issue a letter confirming that the Companies 2012 MX Report is in full compliance with the relevant Commission orders."

The Commission appreciates the Companies' comments, particularly in regard to the clarifications concerning "Ramp-Up reporting" and agrees with the Companies' position that Letter L-60-12 does not vary the directives contained in Orders G-152-07 and G-6-08. Also, the Commission thanks the Companies for its cooperation in improving the clarity and completeness of its annual Main Extensions Report (MX Report), and its efforts to be fully compliant with MX reporting requirements and the directives of Orders G-152-07 and G-6-08.

Notwithstanding the Companies' improved reporting efforts, continued below threshold actual Profitability Index (PI) performance is evident and the Companies have not submitted a proposal to adjust the PI thresholds as required by Order G-152-07.

The Directive in the Decision (G-152-07, page 37) requires that the Companies "determine if the aggregate PI thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1." Letter L-60-12 requests that "The Companies should include a plan to address and comply with the above noted directive for each utility and for each reporting cohort year."

The EES Consulting Report provided as Appendix C of the 2012 MX Report states in the Executive Summary "This report is provided to the FortisBC Energy Utilities (FEU) to address whether its current System Extension policies are consistent with the practices of other gas utilities and to determine whether any changes should be made to the policies."

The EES Consulting Report does not appear to address any adjustments to the PI thresholds, rather it makes a number of observations and comments related to main extensions policies in other jurisdictions and the Companies' existing main extensions policy and how it might be redesigned. As noted in Letter L-32-13 the Commission makes no determination on the EES Consulting Report itself at this time. Also, in Letter L-32-13 the Commission states its intention to initiate a separate process to review the System Extension and Customer Connection Policy, the comments and opinions expressed in the EES Consulting Report may be considered to the extent that it becomes part of a proceeding's evidentiary record.

In conclusion, although the Commission recognizes that Companies' MX results reporting is largely compliant and that there have been significant improvements made, the Companies are not fully compliant as it continues to report below threshold PI performance and has not recommended any go forward PI threshold adjustments aimed at resolving the performance issue. Please contact Ian Dawkins at 604 660 5664 with any further questions.

Yours truly,

Erica Hamilton

ID/nd
Enclosure

Diane Roy
Director, Regulatory Affairs

FortisBC Energy
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Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

July 18, 2013

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc (FEI) and FortisBC Energy (Vancouver Island) Inc. (FEVI) (collectively the Companies)

2012 Year End Report for FEI – FEVI Main Extension (MX) Report – British Columbia Utilities Commission (the Commission) Order G-152-07 Compliance Filing; and FEI Vertical Subdivision Report-Commission Order G-6-08 Compliance Filing (the 2012 MX Report)

FEI-FEVI Response to letter dated July 8, 2013

The Companies are writing in response to the letter from the Commission[1] dated July 8, 2013 (Log No. 43347), which concluded the following:

> "...the Companies are not fully compliant as it continues to report below threshold Profitability Index (PI) performance and has not recommended any go forward PI threshold adjustment aimed at resolving the performance issue."

The Companies wish to stress that we take seriously the issue of our compliance reporting, which is demonstrated in the MX reporting context by the ongoing discussion between the Companies and the Commission Staff, which has led to on-going amendments to and improvements in the MX reporting to address requirements expressed by Commission Staff.

It is the understanding of the Companies from the above cited conclusion that in the Commission's view, the Companies are not in full compliance because: (1) MX performance is below the established aggregate PI threshold of 1.1; and (2) the Companies have not

[1] On March 28, 2013 the Companies filed the 2012 FortisBC Energy Inc. (FEI) and FortisBC Energy (Vancouver Island) Inc. (FEVI) 2012 Year End Report for FEI-FEVI Main Extension Report and FEI Vertical Subdivision Report (the "Report"). On June 5, 2013, the Commission responded to the Report with Letter L-32-13. On June 26, 2013 the Companies responded to Letter L-32-13. On July 8, 2013 the Commission responded to the Companies letter from June 26, 2013.

recommended a plan to adjust the PI performance level on a go forward basis. With respect, the Companies disagree with the Commission's conclusion, and will address each aspect of the Commission's finding below.

1. Performance Below PI Threshold of 1.1

The Companies do not believe that whether the main extensions reported on during a period exceed or fall under the currently established PI threshold is a reporting compliance issue. As stated in the Commission Decision (dated December 6, 2007) accompanying Order G-152-07 (the Decision), reporting on the PI level achieved was for the purposes of determining "if the aggregate PI thresholds need to be adjusted on a go forward basis…". In past MX reports, the Companies have reported on both actual and forecast PI levels in detail. Additionally, the Companies have also reported on whether or not the PI thresholds need to be adjusted on a go forward basis. Thus, it appears to the Companies that the Commission has concluded that the reported performance below the threshold is equivalent to non-compliance with the reporting requirements as set out in Orders G-152-07 and G-6-08. The Companies cannot agree.

2. A Go Forward Plan

The Companies respectfully disagree with the Commission's statement that the Companies have not provided a go-forward plan to adjust the aggregate PI threshold as required by Order G-152-07. As stated in the Companies' letter of June 26, 2013, the Companies have submitted a plan to address our system extension policies more broadly. The EES Report provides a framework to review the Companies' system extension policies on a go forward basis, which can include a consideration of the appropriateness of PI threshold levels established. Whether or not the Commission agrees with the plan submitted by the Companies is, in and of itself, not a matter of compliance. Indeed, as the Commission itself has recognized before, the Commission will leave the determination of the merits of the EES Report to another day.

<u>Conclusion</u>

The Companies respectfully submit that they have complied with the reporting requirements established in Orders G-152-07 and G-06-08, and do believe that, with the above clarifications, the Commission should be in a position to make the same finding.

The Companies are looking forward to moving forward with a review of the current system extension policies, which may well include the examination by the Commission of the appropriateness of the current PI threshold and the merits of the EES Report.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.
FORTISBC ENERGY (VANCOUVER ISLAND) INC.

Original signed by: Stan Crocker

For: Diane Roy

3,569	Total Customers Making A Contribution
7,102	Total Customers Making No Contribution
33%	% Customers Making A Contribution
$ 6,447,213	Total Customer Contributions

$2,150
SLCA Amount/Customer

Target Service Line Cost (P.I. of 1.0)				**$1,521**	**$1,521**	Average Service Line Cost to Company at SLCA of $2,150	
Service Line Cost	**Number of Orders**	**Percentage of Total**	**Cumulative**	**Total Service Line Cost**	**Percentage of Total**	**Cumulative Percentage**	**Average Cost Per Service**
<$300	55	1%	1%	$ 16,277	0%	0.1%	$ 296
$300 - $399	16	0%	1%	$ 7,231	0%	0.1%	$ 452
$400 - $499	58	1%	1%	$ 31,811	0%	0.2%	$ 548
$500 - $599	112	1%	2%	$ 73,740	0%	0.6%	$ 658
$600 - $699	409	4%	6%	$ 314,565	1%	2.0%	$ 769
$700 - $799	1,065	10%	16%	$ 911,987	4%	6.0%	$ 856
$800 - $899	922	9%	25%	$ 873,777	4%	9.8%	$ 948
$900 - $999	829	8%	32%	$ 867,339	4%	13.7%	$ 1,046
$1000 - $1099	646	6%	39%	$ 742,386	3%	16.9%	$ 1,149
$1100 - $1199	535	5%	44%	$ 667,785	3%	19.9%	$ 1,248
$1200 - $1299	425	4%	48%	$ 572,324	3%	22.4%	$ 1,347
$1300 - $1399	426	4%	52%	$ 615,067	3%	25.1%	$ 1,444
$1400 - $1499	324	3%	55%	$ 502,350	2%	27.3%	$ 1,550
$1500 - $1599	320	3%	58%	$ 528,444	2%	29.7%	$ 1,651
$1600 - $1699	262	2%	60%	$ 458,043	2%	31.7%	$ 1,748
$1700 - $1799	233	2%	62%	$ 430,143	2%	33.6%	$ 1,846
$1800 - $1899	200	2%	64%	$ 389,242	2%	35.3%	$ 1,946
$1900 - $1999	174	2%	66%	$ 357,334	2%	36.9%	$ 2,054
$2000 - $2099	184	2%	67%	$ 395,951	2%	38.6%	$ 2,152
$2100 - $2199	182	2%	69%	$ 410,522	2%	40.4%	$ 2,256
$2200 - $2299	189	2%	71%	$ 443,853	2%	42.4%	$ 2,348
$2300 - $2399	162	2%	72%	$ 396,622	2%	44.1%	$ 2,448
$2400 - $2499	161	2%	74%	$ 410,122	2%	45.9%	$ 2,547
$2500 - $2599	161	2%	75%	$ 426,867	2%	47.8%	$ 2,651
$2600 - $2699	155	1%	77%	$ 426,470	2%	49.7%	$ 2,751
$2700 - $2799	116	1%	78%	$ 330,598	1%	51.2%	$ 2,850
$2800 - $2899	133	1%	79%	$ 392,146	2%	52.9%	$ 2,948
$2900 - $2999	104	1%	80%	$ 316,994	1%	54.3%	$ 3,048
$3000 - $3099	117	1%	81%	$ 368,432	2%	55.9%	$ 3,149
$3100 - $3199	114	1%	82%	$ 370,492	2%	57.5%	$ 3,250
$3200 - $3299	114	1%	83%	$ 381,377	2%	59.2%	$ 3,345
$3300 - $3399	108	1%	84%	$ 372,416	2%	60.9%	$ 3,448
$3400 - $3499	87	1%	85%	$ 308,723	1%	62.2%	$ 3,549
> $3500	1,573	15%	100%	$ 8,562,629	38%	100.0%	$ 5,444
Total	**10671**	**100%**		**$ 22,674,059**	**100%**		**$ 2,125**

Contributions for Services	$ 6,447,213
Adjusted Total	**$ 16,226,846**

Footnotes:

1) Total service line costs include costs that were accumulated in orders that did not have specific risers posted. (ie. Standing Jobs)
The FEU Total for 2014 was $1,747,305. This resulted in an additional $164 in added costs per service order.

Appendix E

DRAFT ORDER AND TARIFF CHANGES

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Energy Inc. (FEI)
For Approval to Amend its System Extension and Connection Policies

BEFORE:

(Date)

WHEREAS:

A. In the Decision accompanying Order No. G-152-07, the Commission accepted FEI's proposal to update its System Extension and Connection Policies and directed FEI to file with the Commission on an annual basis a Main Extension (MX) Report that included specific compliance criteria laid out by the Commission; and

B. From 2011 to 2012, the Commission issued Letters L-67-11, L-19-12 and L-60-12 in response to FEI's MX Reports to provide further clarification and guidance on the specific compliance criteria related to MX reporting; and

C. In 2013, FEI initiated a review of its System Extension and Connection Policies through its 2012 MX Report and conducted a series of workshops with interested stakeholder and Commission staff in 2014; and

D. On June 19, 2014 the Commission issued Letter L-34-14, which identified concerns related to FEI's main extension policy; and

E. On August 22, 2014 the Commission issued letter L-44-14 encouraging FEI to complete its System Extension and Connection Policies review and to file an Application for revised main extension policies that addresses the concerns raised in Letter L-34-14 by March 31, 2015; and

F. On December 19, 2014, FEI requested a filing extension for its System Extension Application due to resource constraints arising from the preparation of the Annual MX Report that is required by Commission Order G-6-08 to be file at the end of the first quarter of each year; and

G. On February 20, 2015, the Commission granted a filing extension and directed FEI to file its System Extension Application by June 30, 2015; and

H.

I. The Commission has reviewed the Application filed June 30, 2015 and concludes that FEI has addressed the concerns raised in Letter L-34-14 and that the requested changes as outlined in the Application should be approved.

NOW THEREFORE pursuant to Sections 28 to 30 and 59 to 61 of the Utilities Commission Act, the Commission orders as follows:

1. Effective January 1, 2016, with respect to FEI's MX Test, FEI is directed to:

   a. Discontinue the use of the 20 year term and apply a 40 year Discounted Cash Flow term for use in the MX Test.

   b. Consider a 10 year horizon for customer attachments in circumstances when the party requesting an extension can reasonably demonstrate the existence of a long term plan for growth that exceeds 5 years.

   c. Apply the sliding-scale methodology as proposed in the Application to calculate the overhead rate for main extensions where capital costs are forecast to be greater than $25,000.

   d. Discontinue the application of the +10% and +15% Energy Efficiency Consumption credits for customers with high efficiency and LEED certified appliances.

2. Effective January 1, 2016, with respect to FEI's Customer Connection Policy:

   a. The updated Service Line Cost Allowance (SLCA) amounts of $2,150.00 for single family dwellings and $4,000.00 for duplexes are approved.

   b. The annual update of the SLCA amounts using the approved methodology in November, for implementation January 1 of the following year is approved.

   c. The establishment of the System Extension Fund of $1.0 Million, to be recovered through natural gas delivery rates of non-bypass customers and included in rate base each year as an offset to Contributions in aid of Construction, is approved.

3. Effective with the reporting on 2015 main extensions, FEI is directed to:

   a. Discontinue the current MX reporting requirements.

b. Provide an annual Report to the Commission at the end of the first quarter for the preceding year's main extensions that includes:

    i. The total number of main extensions completed, including the total actual costs for main extensions completed; the forecast PI for all main extensions in aggregate; the total number of customers providing a CIAC, including the total dollar value of CIAC. For main extensions using a 10-year customer addition forecast period, the number of main extensions, the actual costs and the total number and dollar value of CIAC is to be provided separately from the total main extensions.
    ii. The total number of approved requests to access the System Extension Fund, including the total dollar value of the approved requests; and
    iii. Updated MX Test input parameters consistent with approved practices, for implementation January 1 of the following year.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 2015.

BY ORDER

Service Header	Means a Gas distribution pipeline located on private property connecting three or more Service Lines or Meter Sets to a Main.
Service Line	Means that portion of FortisBC Energy's gas distribution system extending from a Main or a Service Header to the inlet of the Meter Set. In case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises.
Service Related Charges	Include, but are not limited to, application fees, Franchise Fees, and late payment charges, plus Social Services Tax, Goods and Service Tax, or other taxes related to these charges.
Standard Fees & Charges Schedule	Means the schedule attached to and forming part of the General Terms and Conditions which lists the various fees and charges relating to Service provided by FortisBC Energy as approved from time to time by the British Columbia Utilities Commission.
Storage and Transport Charge	Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.
System Extension Fund	Means the fund available from FortisBC Energy to provide assistance to eligible new Customers who are required to pay a contribution in aid of construction in order for a Main Extenstion to proceed as set forth in Section 12.11 (System Extension Fund) of these General Terms and Conditions.
Temporary Service	Means the provision of Service for what FortisBC Energy determines will be a limited period of time.
Tenant	A Person who has the temporary use and occupation of real property owned by another Person.
Thermal Energy	Means thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source), and measured by a thermal meter, to premises of a Vertical Subdivision where the thermal meter is used to apportion the gigajoules of Gas consumed by the Gas fired hydronic heating system among the premises in the Vertical Subdivision.

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12. Main Extensions

12.1 System Expansion

FortisBC Energy will make extensions of its Gas distribution system in accordance with system development requirements.

12.2 Ownership

All extensions of the Gas distribution system will remain the property of FortisBC Energy.

12.3 Economic Test

All applications to extend the Gas distribution system to one or more new Customers will be subject to an economic test approved by the British Columbia Utilities Commission. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Main Extension. The Main Extension will be deemed to be economic and will be constructed if the results of the economic test indicate a Profitability Index of 0.8 or greater for an individual main extension.

12.4 Revenue

The projected revenue to be used in the economic test will be determined by FortisBC Energy by:

(a) estimating the number of Customers to be served by the Main Extension;

(b) establishing consumption estimates for each Customer;

(c) projecting when the Customer will be connected to the Main Extension; and

(d) applying the appropriate revenue margins for each Customer's consumption.

The revenue projection will take into consideration the estimated number and type of Gas appliances used and the effect variations in weather conditions throughout the applicable Service Area have on consumption. In addition, the projected revenue from the applicable Application Fees will be included. Only those Customers expected to connect to the Main Extension within 5 Years of its completion, or within 10 Years of its completion for the Main Extension with a planning horizon longer than 5 years as determined by FortisBC Energy will be considered.

Deleted: Customers who intend to install both high efficiency gas fired space (namely an Energy Star rated furnace or boiler) and water heating appliances (tankless water heaters, or water heaters with efficiency rating of 78 percent or greater), will receive a credit of 10 percent of the volume otherwise used for both appliances. Customers who intend to install both high efficiency gas fired space and water heating appliances and attain a minimum of LEED[TM] (Leadership in Energy and Environmental Design) General Certification will receive a credit of 15 percent of the volume otherwise used for both.

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12.5 Costs

The total costs to be used in the economic test include, without limitation:

(a) the full labour, material, and other costs necessary to serve the new Customers including Mains, Service Lines, Meter Sets and any related facilities such as pressure reducing stations and pipelines;

(b) the appropriate allocation of FortisBC Energy's overheads based on the direct capital costs for the construction of the Main Extension;

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(c) the incremental operating and maintenance expenses necessary to serve the Customers; and

(d) an allocation of system improvement costs.

In addition to the costs identified, the economic test will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

In cases where a larger Gas distribution Main is installed to satisfy future requirements, the difference in cost between the larger Main and the smaller Main necessary to serve the Customers supporting the application may be eliminated from the economic test.

12.6 Contributions in Aid of Construction

If the economic test results indicate a Profitability Index of less than 0.8, the Main Extension may proceed provided that the shortfall in revenue is eliminated by contributions in aid of construction by the Customers to be served by the Main Extension, their agents or other parties, or if there are non-financial factors offsetting the revenue shortfall that are deemed to be acceptable by the British Columbia Utilities Commission.

FortisBC Energy may finance the contributions in aid of construction for Customers. Contributions of less than $100 per Customer may be waived by FortisBC Energy.

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12.7 Contributions Paid by Connecting Customers

The total required contribution will be paid by the Customers connecting at the time the Main Extension is built. FortisBC Energy will collect contributions from all Customers connecting during the first five Years after the Main Extension is built. As additional contributions are received from Customers connecting to the main extension, partial refunds will be made to those Customers who had previously made contributions, except those Customers who have received funding under Section 12.11 (System Extension Fund). At the end of the fifth Year, all Customers will have paid an equal contribution, after reconciliation and refunds.

For larger Main Extension projects, FortisBC Energy may use the Main Extension Contribution Agreement for initial contributions. Customers will be billed the contribution amount after the Main Extension is built.

12.8 Refund of Contributions

A review will be performed annually, or more often at FortisBC Energy's discretion, to determine if a refund is payable to all Customers who have contributed to the extension.

If the review of contributions indicates that refunds are due:

(a) individual refunds greater than $100 will be paid at the time of the review;

(b) individual refunds less than $100 will be held until a subsequent review increases the refund payable over $100, or until the end of the five-Year contributory period;

(c) no interest will be paid on contributions that are subsequently refunded;

(d) the total amount of refunds issued will not be greater than the original amount of the contribution; and

(e) if, after making all reasonable efforts, FortisBC Energy is unable to locate a Customer who is eligible for a refund, the Customer will be deemed to have forfeited the contribution refund and the refund will be credited to the other Customers who contributed towards the Main Extension.

For clarity, no refunds will be due to Customers who receive funding under Section 12.11 (System Extension Fund).

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12.9 Extensions to Contributory Extensions

When a Main Extension is attached to an existing contributory Main Extension within the five-Year contributory period for the existing extension, the new extension will be evaluated using the Main Extension Test to determine whether a contribution is required. A prorated portion of the total contribution for the existing contributory extension will be assigned to the new extension on the basis of expected use, point of connection, and other factors. Any contributions toward the cost of the existing extension from Customers on the new extension will be used to provide partial refunds to the contributing Customers on the existing extension, subject to Section 12.11 (System Extension Fund). The total refunds issued will not exceed the total amount of contributions paid by Customers on the existing extension.

12.10 Security

In those situations where the financial viability of a Main Extension is uncertain, FortisBC Energy may require a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy.

12.11 System Extension Fund

FortisBC Energy will budget funds annually to its System Extension Fund which is intended to provide limited assistance to eligible new Customers who are required to pay a contribution in aid of construction of a Main Extension.

Customers must apply for funding from the System Extension Fund, and the applications will be received by FortisBC Energy on or before March 31 or June 30 of each year.

The Customer applying for the System Extension Fund must meet the following requirements:

(a) The Customer must be within FortisBC Energy's Mainland, Vancouver Island, and Whistler Service Areas;

(b) The Customer must be the lawful owner of a separately metered single family , residence, evidenced by a copy of the Land Title Certificate;

  (i) If the copy of the Land Title Certificate is not available, the Customer must give consent to FortisBC Energy to conduct a search of the Land Title Office to verify ownership;

(c) The residence must be used as the principal residence for the Customer; and

(d) The result of the economic test for the Main Extension must indicate a Profitability Index of greater than 0.2 and less than 0.8, and a contribution in aid of construction must be paid by the Customer.

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The number of Customers eligible to receive the System Extension Fund will be limited and the determination of eligibility will be made by FortisBC Energy in its sole discretion, acting reasonably. The maximum System Extension Fund available to a Customer is 50 percent of the required contribution in aid of construction from the Customer, up to a maximum of $10,000 per Customer per residence.

A Main Extension may not proceed until funding has been approved and payment of the contribution is paid. A Main Extension must commence construction within nine calendar Months of the date FortisBC Energy approves the application for the System Extension Fund. Customers who provide a contribution in aid of construction for a Main Extension and who receive funding from the System Extension Fund will not be eligible for a refund as set forth in Section 12.8 (Refund of Contribution).

Standard Fees and Charges Schedule

Application Fee	
Existing Installation	$25.00
New Installation	$25.00
New Installation - Manifold Meters	$25.00 per meter
New Installation - Vertical Subdivision	$25.00 per meter
Service Line Cost Allowance	
Other than a duplex	$2,150.00
Duplex	$4,300.00

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Administrative Charges

Late Payment Charge	1.5% per month (19.56% per annum) on outstanding balance
Dishonoured Cheque Charge	$20.00

Interest on Cash Security Deposits

FortisBC Energy will pay interest on cash security deposits at FortisBC Energy's prime interest rate minus 2%. FortisBC Energy prime interest rate is defined as the floating annual rate of interest which is equal to the rate of interest declared from time to time by FortisBC Energy's lead bank as its "prime rate" for loans in Canadian dollars.

Payment of interest will be credited to the Customer's account in January of each Year.

Metering Related Charges	
Disputed Meter Testing Fees	
Meters rated at less than or equal to 14.2 m^3/Hour	$60.00
Meters rated greater than 14.2 m^3/Hour	Actual Costs of Removal and Replacement
Reactivation Charges	
Performed During Regular Working Hours	$90.00 per hour
Performed After Regular Working Hours	$115.00 per hour

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