Diane Roy
Director, Regulatory Affairs

FortisBC Energy
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

August 13, 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: British Columbia Utilities Commission (BCUC or the Commission) Generic Cost of Capital (GCOC) Proceeding – Stage 2

FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) Response to the BCUC Information Request (IR) No. 1

In accordance with the Regulatory Timetable set out for Stage 2 of the GCOC proceeding by Commission Order G-77-13, FEVI-FEW respectfully submit the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY (VANCOUVER ISLAND) INC. and
FORTISBC ENERGY (WHISTLER) INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

1.0 Reference: Exhibit B1-71, Evidence of FEVI and FEW, pp. 1-2, Tab B, p. 4; Exhibit A2-3, The Brattle Group Report, p. 50

Capital Structures and Equity Risk Premiums of FEVI and FEW

The Evidence states on page 1 that the 2009 TGI, TGVI and TGW Capital Structure (CAP) and Return on Equity (ROE) Decision determined that FortisBC Energy (Vancouver Island) Inc. (FEVI, formerly known as TGVI) and FortisBC Energy (Whistler) Inc. (FEW, formerly known as TGW) are subject to higher overall business risk and set the risk premia for FEVI and FEW at 50 basis points (bps) greater than the benchmark FortisBC Energy Inc. (FEI, formerly known as TGI).

The Evidence proceeds to quote the *obita dicta*, remarks said in passing, from the Commission Panel that it "notes Ms. McShane's testimony that both utilities require greater equity thickness than 40%." [Emphasis added] The Commission then directed FEVI and FEW to file evidence in their next revenue requirements application (i.e., 2012-2013 RRA) as to what equity component best reflects their respective long-term business risk.

1.1 Please confirm that on page 70 of the 2009 CAP/ROE Decision, the Commission reduced FEVI's equity risk premium from 70 bps to 50 bps and determined that FEW's equity risk premium should remain at 50 bps.

Response:

Confirmed.

1.2 When the 2009 CAP/ROE Decision referred to "equity thickness greater than 40%," do FEVI and FEW agree that the "40%" refers to the newly determined equity thickness for FEI based on the evidence on the capital markets and business risk at the time of that proceeding? Do FEVI and FEW agree that it would be more appropriate in the Stage 2 proceeding to refer to the new equity thickness of 38.5 percent that has been effective since January 1, 2013?

Response:

FEVI and FEW do not agree that the Commission was referring to FEI's newly approved equity ratio of 40% in the 2009 Decision when they inferred that both utilities require greater equity thickness than 40%. FEVI and FEW believe that the reference was to the equity thickness of both companies in the context that a higher equity ratio than the 40% was warranted for both

FEVI and FEW. FEVI and FEW's respective common equity ratios were already at 40% prior to the 2009 proceeding, and neither entity had applied to increase it at that time. (FEVI's had been increased to 40% in the 2005 ROE proceeding in tandem with the benchmark utility's common equity ratio being approved at 35%). The Commission in 2009 observed that both FEVI and FEW require greater equity thickness, as neither FEVI or FEW had at the time put forth a request for an increase. It referenced in this regard Ms. McShane's evidence with respect to the need for greater equity thickness. The Commission took specific action by directing the Companies to bring forward evidence to determine the appropriate equity component.

For reference, this is the evidence of Ms. McShane that the Commission was referring to in its 2009 Decision, page 75:

> *"In my opinion, to equate TGVI to the benchmark low risk utility, an allowed common equity ratio of no less than 45-50% would be required (compared to the range of 35-40% for Terasen Gas). Terasen Gas is proposing a 40% common equity ratio for TGVI. I view the proposal as reasonable; however, the difference between the proposed 40% and the indicated range of 45-50% (mid-point of 47.5%) requires an incremental equity risk premium relative to the benchmark low risk utility return."* (Exhibit B-11, Panel 1.6) [Emphasis added.]

Ms. McShane was saying that FEVI's common equity ratio would have to be thicker than the existing 40% proposed by FEVI to equate FEVI with FEI or else there would need to be an additional "incremental risk premium" added. The implication of Ms. McShane's evidence was also that the common equity ratio should be thicker than that of the benchmark utility, whatever the benchmark utility's common equity ratio might be, to equate the utilities.

FEVI and FEW agree that for the purpose of comparing the equity ratio of FEVI and FEW in relation to the benchmark, it is appropriate to refer to FEI's current equity component of 38.5%, effective as of January 1, 2013.

2.0 Reference: Exhibit B1-71, Evidence of FEVI and FEW, p. 2

Generic Cost of Capital Proceeding (Stage 1) Decision dated May 10, 2013

Rate Impact – FEVI and FEW

The GCOC Stage 1 Decision determined a common equity ratio of 38.5percent and a Return to Equity (ROE) of 8.75 percent , effective January 1, 2013, for the benchmark utility FEI.

The expert witness for FEVI and FEW, Ms. McShane, has assessed the business risks facing FEVI and FEW relative to those of the benchmark FEI and concludes that the following common equity ratios and risk premiums over the benchmark ROE for FEVI and FEW reasonably compensate for the two utilities' higher business risks relative to FEI:

- FEVI – 43.5 percent common equity, with an ROE risk premium of 0.50 percent; and
- FEW – 45 percent common equity, with an ROE risk premium of 0.75 percent

2.1 Using the assumption that the risks faced by FEVI and FEW and the respective equity risk premiums faced by the utilities have remained unchanged for 2013, please estimate their respective revenue requirements, rate impact and bill impact based on the new Benchmark ROE determined in Stage 1 for 2013, holding all other factors such as equity thickness constant (i.e., a reduction in ROE of 75 bps).

Response:

For FEVI, a decrease to the existing approved 2013 ROE from 10.00% to 9.25% solely as a result in the change in the benchmark in the Stage 1 decision would result in a decrease in revenue requirement of $3.2 million and a notional decrease in the delivery rate of 1.6%. However, given the existence of the Revenue Stabilization Deferral Account (RSDA) and the rate freeze, the revenue requirement change would end up reducing the RSDA balance and there would be no immediate rate or bill impact to customers.

For FEW, a decrease to the existing approved 2013 ROE from 10.00% to 9.25% solely as a result in the change in the benchmark in the Stage 1 decision would result in a decrease in revenue requirement of $160 thousand, a decrease in the delivery rate of 1.9%, and an approximate decrease in an average annual residential customer bill of $22 per year.

2.2 Using the assumption that the Commission approves FEVI's and FEW's recommendations on common equity and ROE risk premiums, please estimate the revenue requirements, rate impact and bill impact, holding all other factors constant for 2013.

Response:

FEVI are providing a response to this question in the context of the subsequent questions in this series asking about how to implement rate changes, since it is well established that customer rate impacts should not be considered when determining a fair return.

For FEVI, an increase to the existing approved equity thickness from 40.0% to 43.5% and a decrease to the existing approved 2013 ROE from 10.00% to 9.25% would result in a decrease in revenue requirement of $1.2 million and a notional decrease in the delivery rate of 0.6%. However, given the existence of the Revenue Stabilization Deferral Account ("RSDA") and the rate freeze, the revenue requirement change would end up reducing the RSDA balance and there would be no rate or bill impact to customers.

For FEW, an increase to the existing approved equity thickness from 40.0% to 45.0% and a decrease to the existing approved 2013 ROE from 10.00% to 9.50% would result in an increase in revenue requirement of $57 thousand, an increase in the delivery rate of 0.7%, and an approximate increase in an average annual residential customer bill of $8 per year.

2.3 Do FEVI and FEW have views regarding: (a) whether their 2013 interim rates should be made permanent; and (b) whether the allowed cost of capital as a result of the review that takes place in Stage 2 should be made effective January 1, 2013 or January 1, 2014?

Response:

The Commission's Letter L-31-13A, issued on June 5, 2013, appears to have determined that the Stage 2 decision will be effective January 1, 2013.

2.4 If the allowed costs of capital from this proceeding were to be made effective January 1, 2013 would it be efficient to recover the difference between the interim and approved cost of capital in 2013 from a deferral account to be recovered perhaps as a rate rider amortized over one or two years? What approach would work best for FEVI & FEW?

Response:

For FEVI, the most efficient way to recover the difference between interim and approved cost of capital in 2013 would be to allocate the difference to the Revenue Stabilization Deferral Account and keep customer rates the same as they have been for the last several years.

For FEW, the most efficient way to recover the difference between interim and approved cost of capital in 2013 would be to record the difference to a deferral account to be returned to or recovered from customers over one year, 2014, or the remainder of 2014 depending on when the Stage 2 Decision is issued.

3.0 Reference: Exhibit B1-71, Evidence of FEVI and FEW, p. 8

Development since 2009 Affecting Relative Risk

"The one significant development since 2009 affecting relative risk is the Common Rates Application Decision. The possibility for FEVI to address long-term competitive issues by amalgamating with FEI and adopting common rate structures was not a central issue in 2009, but was part of the factual context. Moody's Investor Service (Moody's) Credit Opinion March 16, 2009, which was before the Commission in 2009, discussed amalgamation and the adoption of common rates at length as a potential solution for addressing FEVI's competitive challenges that have been impacted by the expiry of government royalty revenues."

3.1 Is it the position of FEVI and FEW that the obvious solution to addressing long-term competitive issues is through amalgamation? If not, what are the other possibilities?

<u>Response:</u>

As discussed in Appendix A of Exhibit B1-71, FEVI and FEW face number of risks and long-term competitive issues, one of which is high delivery rates for both FEVI and FEW and loss of royalty revenues for FEVI. Recognizing these competitive challenges, the FEU pursued amalgamation. The FEU believe it is the only suitable solution that offsets significant rate increases for FEVI customers and insulates FEW customers from volatility associated with changes in throughput and rate impacts from large capital investments.

3.2 Other than the Common Rates Application, what are the other developments that could have changed the business risks of FEVI and FEW relative to the benchmark utility since 2009?

<u>Response:</u>

Please refer to the response to BCUC FEVI-FEW IR 1.3.1.

3.3 What was the FEVI natural gas commodity price effective June 2009 (with royalty revenue reduction) compared to the FEVI natural gas commodity price in June 2013 (without royalty reduction)?

Response:

The Commission approved FEVI unit cost of gas after royalty adjustments for 2009 was $6.40 per gigajoule and the Commission approved FEVI cost of gas for 2013 is $5.98 per gigajoule. Both of these costs are exclusive of the British Columbia Provincial Carbon Tax first introduced in July 2008. This increased FEVI customers' natural gas charges by $0.4966 per gigajoule effective July 1, 2008, and is currently $1.4898 per gigajoule. FEVI customers have not seen a increase since 2009 given the approved approach to freeze rates delivered at the burnertip. FEVI's challenge from the perspective of price competition lies within the current higher delivery rates than the benchmark, as well as challenge of higher delivery rates in the future.

3.3.1 Hasn't the collapse in natural gas prices and the escalation in electricity rates offset, to a large degree, the concerns that existed for the loss in the royalty revenue subsidy?

Response:

No. The royalty revenue arrangement offset the cost of a significant volume of FEVI's overall gas supply requirements and was directly linked to the market price of natural gas. In other words, when market prices were high, the royalty revenue credit was also high, and likewise when market prices decreased, the royalty revenue also decreased. In this way the royalty arrangement acted as a commodity hedge that served to reduce both overall gas costs and market price volatility. Now that the royalty revenue arrangement has expired, FEVI must recover the full cost of its gas from customers which in turn will be subject to the full impact of market price volatility.

As discussed in the GCOC Phase 1 proceeding, the FEU recognize that the outlook for natural gas supply and overall market prices has improved since the peak in mid-2008 due to the production technology advancements that have unlocked the potential of shale gas reserves across North America. Indeed, increased production, slow demand response, and warmer than normal weather causing record storage levels did lead to a "collapse" in natural gas prices in early 2012 to levels below the cost of production. Since that time, however, there has been significant price volatility and market prices have more than doubled. For example, AECO prices in April 2011 were close to $3.60/GJ and then fell to about $1.40/GJ by April 2012. Since then market prices rebounded back up to $3.60/GJ by April 2013. In comparison, average AECO prices in September 2009 were $2.84/GJ.

In addition, as discussed in the response to BCUC IR 1.3.3, although the FEVI core market customer burnertip rates have been frozen since 2009 the carbon tax increases from 2009 to now have resulted in overall higher bills for customers. Furthermore, the current rates are not sufficient to recover the full revenue requirements as evidenced by the fact that FEVI is now beginning to draw down the RSDA balance. The lower commodity rates since 2009 contributed to FEVI accumulating a relatively large RSDA balance which will allow FEVI to mitigate rate increases in the short term but will not provide a longer term, sustainable solution. Regarding the relative change in gas prices compared to electricity rates, such changes would affect FEI as well, and should be reflected in the benchmark cost of capital.

4.0 Reference: Exhibit B1-71, Tab A, pp. 6-7

Business Profile of FEI, FEVI, and FEW

Table 2 summarizes the business profiles of FEVI and FEW and shows that FEVI and FEW,are much smaller utilities than FEI when measured by their service area, rate base, load, and customer base. Their respective customer bases and economic bases are also less diverse.

4.1 For each utility, please expand Table 2 to show annual changes for each year from 2009. For number of customers and net customer additions, please include data by customer class.

<u>Response:</u>

The following data tables extend Table 2.

Rate Base	2009	2010	2011	2012
FEI	$2,462.1	$2,525.2	$2,563.6	$2,692.8
FEVI	$532.9	$547.6	$666.1	$778.7
FEW	$31.5	$45.4	$45.3	$41.7

Energy (TJs)	2009	2010	2011	2012
FEI	165,607	168,222	174,813	178,735
FEVI	35,449,086	36,557,222	37,224,498	38,083
FEW	632	765	721	686

Accounts	2009	2010	2011	2012
FEI				
Accounts	**836,975**	**843,844**	**849,188**	**839,040**
Residential	753,735	760,559	765,553	759,709
Commercial	82,175	82,316	82,733	78,430
Industrial	1,065	969	902	901
FEVI				
Accounts	**97,704**	**100,136**	**102,110**	**101,098**
Residential	88,321	90,671	92,554	92,067
Commercial	9,383	9,465	9,556	9,031
FEW				
Accounts	**2,580**	**2,592**	**2,649**	**2,612**
Residential	2,250	2,262	2,296	2,271
Commercial	330	330	353	341

Account Additions	2009	2010	2011	2012
FEI				
Residential	4,822	6,824	4,994	-5,844
Commercial	299	141	417	-4,303
Industrial	-31	-96	-67	-1
FEVI				
Residential	2,785	2,350	1,883	-487
Commercial	149	82	91	-525
FEW				
Residential	116	12	34	-25
Commercial	7	0	23	-12

*Note: In the new SAP-based CIS, the algorithm for determining the number of customers has changed. As a result the 2012 net customer additions appear to fall. The decline is only a result of the changed algorithm and is not indicative of recent trends.

Growth Rates	2009	2010	2011	2012
FEI	1%	1%	1%	1%
FEVI	3%	2%	2%	2%
FEW	5%	0%	2%	2%

Rate Base per Customer	2009	2010	2011	2012
FEI	$2,942	$2,992	$3,019	$ 3,209
FEVI	$5,454	$5,469	$6,523	$ 7,702
FEW	$12,209	$17,515	$17,101	$ 15,965

Customer Profile by Account	2009	2010	2011	2012
FEI				
Residential	90.1%	90.1%	90.2%	90.0%
Commercial	9.8%	9.8%	9.7%	9.0%
Industrial	< 1%	< 1%	< 1%	< 1%
FEVI				
Residential	90.4%	90.5%	90.6%	90.0%
Commercial	9.6%	9.5%	9.4%	9.0%
Industrial	-	-	-	-
FEW				
Residential	86.7%	86.9%	86.7%	87.0%
Commercial	13.3%	13.1%	13.3%	13.0%

Customer Profile by Demand	2009	2010	2011	2012
FEI				
Residential	42.3%	41.6%	39.4%	39.0%
Commercial	28.5%	27.7%	27.5%	27.0%
Industrial	29.2%	30.6%	33.0%	34.0%
FEVI				
Residential	13.1%	12.9%	16.5%	12.0%
Commercial	20.2%	19.3%	24.6%	18.0%
Industrial	66.6%	67.9%	58.9%	70.0%
FEW				
Residential	29.8%	30.2%	29.8%	30.0%
Commercial	70.2%	69.8%	70.2%	70.0%

4.1.1 Are there any notable differences now as compared to FEI since 2009? Please comment on the favourable and unfavourable changes relative to FEI.

Response:

Total energy demand for FEI and FEVI has continued to increase gradually year over year while FEW peaked in 2010 and has been gradually declining since. The 2010 peak is likely coincident with the Winter Olympics.

Account growth rates for FEI remain stable at approximately 1%. Growth rates for FEVI declined from 3% in 2009 to 2% and have held steady at 2% since. Growth rates for FEW are more volatile owing to the smaller base and an uptick seen prior to the Winter Olympics.

Customer profiles by demand for FEI have changed since 2009 as the industrial rate classes now account for a larger portion of the total energy. At the same time the residential portion has fallen from just over 43% in 2009. The profiles by demand for FEVI and FEW remain stable.

Customer profiles by account remain stable and unchanged in all three companies.

Rate base for FEVI peaked in 2011 due to Mt. Hayes while FEW's peaked in 2010 due to costs related to the Whistler Pipeline. FEVI's rate base per customer is still over double that of FEI's and FEW's rate base per customer is higher than it was in 2009, at approximately 5 times that of FEI's.

Overall, these factors tend to suggest that FEW's and FEVI's risk relative to that of FEI has changed little since 2009.

4.1.2 FEVI and FEW each experienced higher customer growth rates of 2 percent in 2012 compared to the 1 percent for FEI? What is the outlook for the next two years?

Response:

Residential customer additions are correlated with housing starts data. As such, housing starts forecast from Conference Board of Canada (CBOC) are used to forecast our own customer additions. The latest CBOC provincial outlook reports a modest decline of -6.3% in 2013 followed by a positive growth of 8.4% in 2014. FEU anticipates that our own customer base will grow in line with the aforementioned growth rates by CBOC.

Commercial customer additions are forecast using a three year average of the actual customer additions experienced by the company. Based on the historical additions, very modest growth rates are expected on an aggregated basis, namely 1.3% for FEVI and 2.2% for FEW in 2013 and 2014.

4.1.2.1 What were the average annual customer growth rates for FEVI, FEW and FEI respectively during the past four years 2009 to 2012?

Response:

Please refer to the response to BCUC FEVI-FEW IR 1.4.1.

4.2 Please expand Table 2 to show a Use Per Customer (UPC) column. Are there any notable UPC differences now as compared to FEI since 2009?

Response:

The following table provides residential and commercial Use Per Customer for FEI, FEVI and FEW since 2009. Notable UPC difference is shown for both FEI and FEW compared to FEI since 2009.

Normalized UPC 2009 to 2012

(GJ/Year)	2009	2010	2011	2012
Residential UPC				
FEI	93.3	92.6	90.4	92.2
FEVI	53.5	52.4	51.8	49.5
FEW	82.6	99.5	94.7	89.4
Commercial UPC				
FEI	576	568	584	625
FEVI	771	749	744	781
FEW	1,386	1,637	1,490	1,319

Similar to FEI, FEVI residential UPC has been declining since 2009. After an increase from 2009 to 2010, FEW residential UPC has been declining since 2010 at a greater rate than FEI and FEVI. The increase in UPC for FEI is a result of the CIS (change in customer counting methodology) adjustment.

Volatility has been seen in commercial UPC of all three utilities. While FEI commercial UPC shows an increase since 2010 after an increase from 2009 to 2010, FEVI experienced a decrease from 2009 to 2011 and then increased again in 2012. FEW commercial UPC increased from 2009 to 2010, and then decreased from 2010 to 2012. Given the smaller customer base of FEVI and FEW, greater changes are expected on their commercial UPC.

The Company does not measure industrial demand using Use per Customer.

The CIS adjustment in 2012 resulted in changes in UPC across all regions and rate classes. The overall adjustment was -14,892 for FEI, -3,029 for FEVI and -88 for FEW resulting in higher UPC values for most regions and rate classes. LCS 3 Rate Schedule in FEVI is the exception where UPC decreased as a result of adding 47 customers.

5.0 Reference: Exhibit B-71, Tab A, p. 8; Commission Letter L-32-13

FEVI and FEW Geographic and Service Area

FEVI and FEW operate in a smaller geographic area than FEI, serving few communities in those service territories.

The Evidence states that FEVI's and FEW's high capital costs per customer reflect the significant investment in transmission infrastructure required to reach their small customer base and their lower market penetration relative to other natural gas Local Distribution Companies.

Table 2 shows that FEVI's rate base per customer is more than double that of FEI, and FEW's rate base per customer is almost five times greater than that of FEI. FEVI and FEW must recover their fixed costs from a smaller customer base, which translates to higher cost per customer or higher delivery rates.

In Letter L-32-13, the Commission comments on the 2012 FEI and FEVI Main Extension (MX) Report. It states that "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."

5.1 To what extent would uneconomical main extension installations (which lead to higher cost per customer and higher delivery rates) be considered controllable risks?

Response:

It is not factually correct to classify any main as "un-economical" until the end of the useful life of the main extension (this being 40+ years). The results included in the 2012 Main Extension Report, as referenced above, represent a snap shot in time only and are not indicative of the final impact of a main extension on ratepayers. In fact, due to the 20 year DCF (Discounted Cash Flow) time frame of the Main Extension Test, the re-forecasting methodologies required by Staff and the variances between forecast and actual consumption values, the results contained in the annual Main Extension Report submissions should only be considered to be preliminary in nature.

Furthermore, a discussion of the external influences associated with the four main pillars of the Companies' Main Extension Test is provided in Section 5 (pages 22-25) of the 2012 Main Extension Report. (refer to Attachment 5.1) These pillars, namely the customer consumption, attachments, mains costs and service costs all contain some degree of uncertainty. The uncertainty cannot be classified as "controllable risk" when taken within the context of forecasted attachments and customer consumption because the Companies do not have influence over these external factors. These main extension test elements are controlled by the builder or homeowner requesting the service(s), external market fundamentals, and the individual consumption patterns of each customer attaching to the system.

Using the best information at the time, the Company administers the MX test, and attaches customers that meet the MX Test parameters and the associated tariff pages and policies which have been approved by the Commission.

5.1.1 In the view of FEVI and FEW, to what extent should shareholders be compensated for taking controllable risks?

Response:

Please refer to the response to BCUC FEVI-FEW IR 1.5.1. Many aspects influencing the economics of a main extension are outside of the utility's control. However, to respond directly to this question, even if risks are controllable, it is appropriate to compensate the shareholder where taking the risk is prudent. Many aspects of running a utility involve taking some degree of risk and the prudence test is used to determine when utility actions are unreasonable and should not be included in rate base.

6.0 Reference: Exhibit B1-71, Tab A, p. 10

Customer Profile – Vancouver Island Gas Joint Venture (VIGJV) Industrial Load

"The pulp and paper mills served by FEVI take gas service under a single service agreement. Since the term of the existing agreement with the VIGJV started in 1995, two of the original seven mills have shut down permanently. The VIGJV's original contract demand was 60 TJs per day; however, it has been at the minimum level under the agreement of 8 TJs per day since August of 2008. The VIGJV recently increased their contract demand under the existing agreement up to 12 TJs per day, effective November 1, 2012; however, they continue to have the right to reduce their contract demand to the minimal level on 1 year notice."

6.1 Does the uncertainty derived from VIGJV demand volume means that it could go up as well as down, as the description above indicates?

Response:

No, the original agreement with the VIGJV was amended in 2005, and subsequently the VIGJV exercised their right to reduce the contract demand from 12.5 TJs to the minimum level of 8 TJs per day in Aug 2008. Under the amended agreement, any requests for reinstatement of contract demand is to a maximum of 12 TJs per day and any requests for firm capacity above 12 TJs per day would be on an annual review basis (effective November 1 of each year) and subject to the capacity being available. However the current agreement expires in 2017, and there is no certainty on what the VIGJV requirements will be beyond that time.

6.2 VIGJV has been taking contract demand at the minimum level since 2008 and has recently increased their demand. Please confirm that the risk relative to FEI has not increased since 2009. Given the increase in contract demand in 2012 and recent improvements in the business climate for the remaining VIGJV mills, would that not imply that the VIGJV industrial business risk of FEVI has been reduced since the last Cost of Capital proceeding in 2009?

Response:

Regarding FEVI's risk associated with the VIGJV, FEVI does not see a material change in the risk on a prospective basis associated with the VIGJV. While there has been an increase in contract demand, the impact to FEVI if this customer were to cease to be a customer, or materially reduce its load on a more permanent basis, is still prevalent and has not been reduced due to recently incremental demand.

With regard to the relationship between the state of the industry and the allowed return for FEVI, including its capital structure and equity risk premium compared to FEI, please refer to the response to BCUC FEVI-FEW IR 1.8.1.

7.0 Reference: Exhibit B1-71, Tab A, pp. 10-11

Customer Profile – Island Generation (IG) Agreement with BC Hydro – FEVI

In 2008, FEVI entered into an agreement with British Columbia Hydro and Power Authority (BC Hydro) for transportation service to IG until April 12, 2022; however, BC Hydro has the right to terminate the agreement early on or after November 1, 2015 upon giving 24 months notice. If BC Hydro were to terminate its contract, the remaining FEVI customers would be faced with a substantial delivery margin increase of approximately 11 percent, or over $12 million.

Today, the Elk Falls mill has been shut-down and the IG facility is fully dispatchable by BC Hydro and generally is run as a peaking facility or emergency back up to the BC Hydro system. This change in operations is reflected by the change in contract demand for this facility from 50 TJ/day to 45 TJ/day in November 2011 and further reduction down from 45 TJ/day to 40 TJ/day in November 2012, resulting in about 20 percent reduction in firm demand charges paid by BC Hydro to FEVI. This also creates greater uncertainty on whether BC Hydro will elect to terminate early, and/or renew the transportation service agreement after 2022.

Footnote 4 on page 11 notes that under the current agreement, BC Hydro can increase or decrease their contract demand by up to 5 TJ per day to a maximum of 50 TJ and a minimum of 40 TJ per day with one year's notice.

7.1 As of this date, has FEVI received any indication that BC Hydro would exercise its right to terminate the transportation service agreement on November 1, 2015?

Response:

No, as of this date, FEVI has not received any indication that BC Hydro would exercise its right to terminate the transportation service agreement on November 1, 2015. The increased uncertainty exists due to the change in nature of use of the facility, not due to receipt of notice of possible termination.

7.2 FEVI considers that there is greater uncertainty with respect to BC Hydro electing to terminate early due to the fact that IG has changed from a "must run facility" to a fully dispatchable peaking facility. If BC Hydro elects to terminate the agreement and if a change in circumstances requires that IG facility is needed as a base load facility, does BC Hydro have to re-negotiate a new transportation service agreement?

Response:

Yes.

8.0 Reference: Exhibit B1-71, Tab A, pp. 11-12; Exhibits A2-54, A2-55

Economic Base – Pulp and Paper Industry

"The bulk of FEVI's industrial customers as defined by customer count are pulp and paper mills. The pulp and paper industry is cyclical, with the fortunes of the sector tied to the strength of export markets and the value of the Canadian dollar. The long-term health of the BC pulp and paper sector is dependent on the BC industry's ability to compete in global markets. As an illustration of FEVI's dependency on the VIGJV group of mills, a total shutdown of these mills would require a 5 percent delivery margin increase, the equivalent of over $6 million, for FEVI customers. Even the closure of some of the mills would have a measurable impact."

BC Stats on June 26, 2013 released its Business Indicators the following information (Exhibit A2-54):

11 – Manufacturing — Non-Durables, NAICS based

Period	Total Non-Durables	Food	Beverage	Paper	Printing & Related Support	Plastics & Rubber
	Value of Manufactured Shipments- Seasonally Adjusted					
	$ thousand					
	Seasonally Adjusted					
2009	17,146,431	6,050,243	1,220,502	4,398,030	631,245	992,090
2010	18,259,831	6,347,397	1,185,066	4,975,187	634,949	1,091,781
2011	19,136,098	6,811,405	1,128,171	5,145,688	-	1,131,591
2012	18,832,306	7,049,340	-	4,477,973	-	1,056,725

BC Stats on July 5, 2013 released its Earnings and Employment Trends the following information (Exhibit A2-55):

3.4A B.C. INDUSTRIAL COMPARISON - EMPLOYMENT (Actual)

	All Goods Prod. Industries (incl. Utilities)		Agriculture		Forestry & Logging		Fishing Hunting & Trapping		Mining & Oil & Gas		Total Manufacturing		Selected Breakout of Manufacturing: Food and Beverage		Wood		Paper		Construction	
	('000)	% Chg	('000)	% Chg	('000)	% Chg	('000)	% Chg	('000)	% Chg	('000)	% Chg	('000)	% Chg	('000)	% Chg	('000)	% Chg	('000)	% Chg
2003	409.6		33.1		27.1		4.4		13.1		203.3		31.0		48.4		14.1		117.4	
2004	428.5	4.6	37.2	12.4	21.1	-22.1	2.9	-34.1	11.0	-16.0	206.0	1.3	30.8	-0.6	45.7	-5.6	11.8	-16.3	141.6	20.6
2005	444.1	3.6	39.0	4.8	21.3	0.9	2.1	-27.6	13.7	24.5	194.8	-5.4	30.9	0.3	45.1	-1.3	12.1	2.5	162.9	15.0
2006	453.8	2.2	35.0	-10.3	21.4	0.5	2.7	28.6	19.0	38.7	193.3	-0.8	23.8	-23.0	43.8	-2.9	15.0	24.0	174.0	6.8
2007	483.5	6.5	35.5	1.4	24.2	13.1	2.9	7.4	19.9	4.7	199.4	3.2	27.5	15.5	43.7	-0.2	15.0	0.0	192.1	10.4
2008	490.9	1.5	33.1	-6.8	17.3	-28.5	2.2	-24.1	25.4	27.6	184.8	-7.3	30.3	10.2	33.6	-23.1	13.1	-12.7	214.9	11.9
2009	438.8	-10.6	33.0	-0.3	13.9	-19.7	2.2	0.0	24.2	-4.7	160.8	-13.0	28.9	-4.6	26.8	-20.2	10.8	-17.6	192.7	-10.3
2010	442.7	0.9	31.8	-3.6	16.1	15.8	1.9	-13.6	22.7	-6.2	165.8	3.1	27.3	-5.5	28.7	7.1	9.8	-9.3	190.5	-1.1
2011	447.4	1.1	26.1	-17.9	14.0	-13.0	n.a.	n.a.	24.7	8.8	163.9	-1.1	30.3	11.0	30.1	4.9	9.2	-6.1	204.6	7.4
2012	459.1	2.6	26.0	-0.4	17.7	26.4	2.1	n.a.	26.2	6.1	179.2	9.3	31.8	5.0	26.7	-11.3	12.0	30.4	192.9	-5.7

8.1 In the views of FEVI, to what extent should the Commission consider the strength of the export market as well as B.C. Industry's ability to compete globally when reviewing FEVI's cost of capital?

Response:

In determining what is a reasonable capital structure and equity risk premium for FEVI, the Commission should take into account the longer-term risks to which FEVI is exposed arising from the nature of its customer base. In other words, the focus for determining an appropriate capital structure and equity risk premium for FEVI is not the fact that the circumstances of the pulp and paper industry may have improved as the economy has improved (or conversely deteriorated in less favourable economic times), but the forward looking risks that are associated with serving a service area where the pulp and paper industry plays a key role. In this regard, it is important to recognize that the principal risk to FEVI relating to the reliance on customers in the pulp and paper industry is primarily the failure, or closure of the operations, of its customers in, and related to, the industry. Further, inasmuch as FEI, the benchmark utility, also serves customers in the pulp and paper industry, it is the forward looking risks to which FEVI is exposed relative to those of FEI.

8.2 Would FEVI agree that the information from BC Stats is useful and representative to assess the general BC pulp and paper industry including the Vancouver Island region? If not, why not?

Response:

Yes. With regard to the relationship between the state of the industry and the allowed return for FEVI, including its capital structure and equity risk premium compared to FEI, please refer to the response to BCUC FEVI-FEW IR 1.8.1.

8.3 Would FEVI agree that for the 2010-2012 years the paper manufacturing industry, in terms of value of shipments, is no worse than in 2009? If not, why not?

Response:

Yes. With regard to the relationship between the state of the industry and the allowed return for FEVI, including its capital structure and equity risk premium compared to FEI, please refer to the response to BCUC FEVI-FEW IR 1.8.1.

8.4 Would FEVI agree that employment in the BC paper manufacturing industry in 2012 has improved as compared to 2009? If not, why not?

Response:

Yes. With regard to the relationship between the state of the industry and the allowed return for FEVI, including its capital structure and equity risk premium compared to FEI, please refer to the response to BCUC FEVI-FEW IR 1.8.1.

8.5 Do FEVI and FEW believe that business cycle and the stage of the business cycle in B.C. has already been considered in GCOC proceeding Stage 1 when the Commission assessed the various financial models to estimate the Benchmark ROE?

Response:

Ms. McShane indicates that the models that were used to estimate the cost of equity do, to some extent, capture effects of the phase of the business cycle generally on the cost of equity, as reflected, for example, in the forecast risk-free rate and the market risk premium in the Capital Asset Pricing Model and in the dividend yields of utilities in the DCF model. The models themselves do not, however, capture factors that are specific to the state of the business cycle in BC, as the models are applied to samples of companies that operate in many regional economies and participate in global capital markets.

8.5.1 Would FEVI agree that the pulp and paper industry in BC, including Vancouver Island, has generally improved since 2009? If not, why not?

Response:

Yes. With regard to the relationship between the state of the industry and the allowed return for FEVI, including its capital structure and equity risk premium compared to FEI, please refer to the response to BCUC FEVI-FEW IR 1.8.1.

8.5.2 How would FEVI assess its economic base in terms of industrial customers since 2009? Have the margins from industrial customers increased compared to overall margins from other customer classes?

Response:

Since 2009, FEVI's economic base in terms of industrial customers (VIGJV and BC Hydro) has decreased from 7 sites to 6 sites. In February of 2009, Catalyst paper (member of the VIGJV) indefinitely shutdown it's Elk Falls site near Campbell River and Catalyst Paper announced the closure would be permanent in July 2010. As can be seen in the table below, margins from industrial customers decreased slightly from 2009 through 2011 and increased slightly in 2012. The levels are similar to what they were in 2009.

FEVI MARGIN $000	2009	2010	2011	2012
% to Total Margin	17.1%	15.2%	15.1%	16.8%

9.0 Reference: Exhibit B1-71,Evidence of FEVI and FEW, p. 9; Tab A, p. 12; Tab B, p. 10;

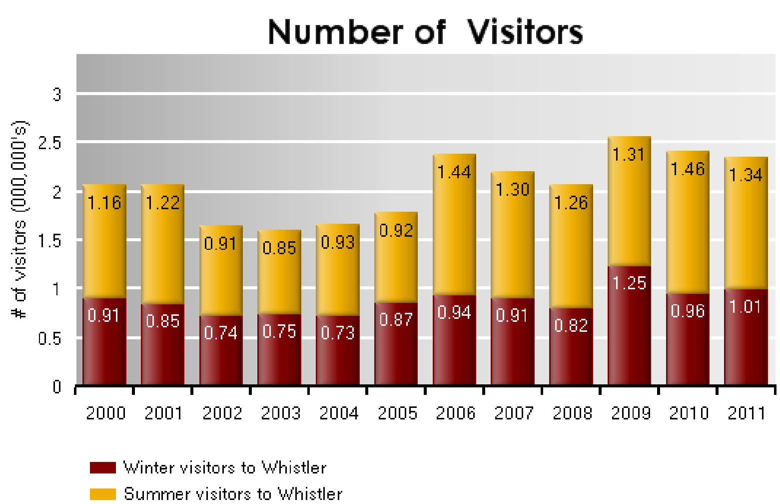
Economic Base – Whistler Tourism Industry

The FEW 2009 RRA Decision had referenced and accounted for unique longer-term risk factors, notably related to FEW's heavy reliance on tourism and less diverse customer base.

Nine of FEW's largest ten customers are either condominium developments or resort-style hotels, and all current commercial development in Whistler is related directly, or indirectly, to tourism. Tourism is a cyclical industry, whose fortunes are dependent on the availability of discretionary income, and thus on the economic strength of the markets from which it draws revenues.

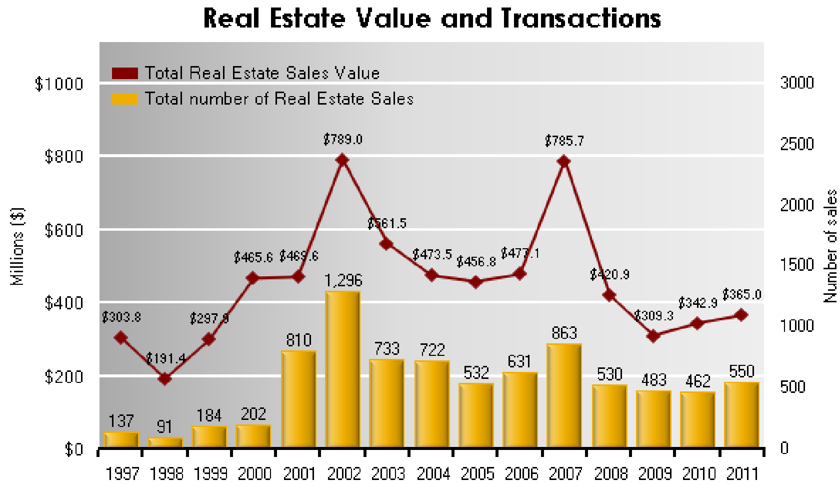
Figure 4 shows that FEW's commercial rate classes are a mix of various sectors, with the top three sectors being real estate (35percent), accommodation (26 percent) and retail (11 percent).

Whistler2020 shows the following information regarding Whistler's facts and figures.[1]



---

[1] http://www.whistler2020.ca/monitoring/business_resort_development
http://www.whistler2020.ca/Indicators/2011/Visitor_Number



9.1 Would FEW agree that the information from Whistler2020 is useful and representative of the Whistler commercial sector, including the tourism industry? If not, why not?

Response:

Yes, directionally the information is useful. However, please refer to the response to BCUC FEVI-FEW IR 1.8.1, which addresses the state of the pulp and paper industry and how it relates to FEVI's allowed return. The same broad conclusions apply to FEW in regards to the tourism industry.

9.2 Does FEW agree that in general the number of visitors in Whistler has been similar as compared to 2009?

Response:

No, the number of visitors appears to have been lower in 2010 and 2011 than in 2009, not higher as the question suggests. However, FEW would not maintain that the decline in and of itself leads to higher risk. With regard to the relevance of the number of visitors in 2009 versus 2010 and 2011, please refer to the response to BCUC FEVI-FEW IR 1.9.1.

Year	Winter	Summer	Total	Change Compared to 2009
2009	1.25	1.31	2,560,000	
2010	0.96	1.46	2,420,000	(140,000)
2011	1.01	1.34	2,350,000	(210,000)

9.3 Does FEW agree that in general the real estate market in Whistler (real estate value and transactions) is no different or has improved now as compared to 2009? Does FEW wish to make any adjustments for significant events such as the 2010 Winter Olympics to account for outliers? If so, please specify what type of adjustments should be made and the basis of such adjustments.

Response:

FEW agrees, and does not wish to make any adjustments. Please refer to the response to BCUC FEVI-FEW IR1 9.1.

9.3.1 Has FEW considered that the continued addition of tourism infrastructure at Whistler that will improve both the summer and winter tourism (e.g., Olympic Plaza and the two new lifts for this winter)? If yes, how? If not, why not?

Response:

FEW is aware of the addition of additional tourism infrastructure, which, all other things equal, increases the tourism focus of the service area and makes its long-term prospects more reliant on a single industry. Nevertheless, FEW does not believe that the addition of the tourism infrastructure referenced alters the utility’s forward looking business risk profile compared to 2009.

9.4 Has FEW considered any development studies or statistics regarding Whistler’s commercial development and tourism industry?

Response:

FEW is aware of the trends in Whistler's commercial development and tourism industry but has not undertaken any statistical analysis of either as such analysis would not provide any insight into the utility's throughput. Nor does FEW believe that the statistical analysis of the trends in commercial development and the tourism industry would provide any further insight into the utility's forward looking business risk profile.

Market Research has not undertaken any research specific to the commercial sector in Whistler. The primary barriers to undertaking research in the FEW service territory are the small size of the overall market and the type of customer.

FEW residential customers were included in the 2002, 2008 and 2012 Residential End Use Studies and the response rate in all three studies was considerably below the participation rate for other service territories. In the 2012 study the FEW response rate was 5.2% compared to the overall survey response rate of 13.7%. The low participation rate is due to the seasonal nature of home occupancy in Whistler. The participation rate in commercial studies is generally lower than residential studies and given that a significant portion of FEW commercial customers are MFD buildings in rental pools, FEW would expect that participation in any commercial study would be very low.

9.4.1 If yes, please compare the information: (i) between 2009 versus present time; and (ii) last 10 years. Please include relevant studies or statistics. If not, why not?

Response:

Please refer to the response to BCUC FEVI-FEW IR 1.9.4.

10.0 Reference: Exhibit B1-71, Tab A, pp. 3, 15 – 17

Current Price Differentials – FEVI and FEW

FEVI and FEW take the position that while they have higher natural gas rates than FEI, BC Hydro's electricity rates are consistent (i.e., postage stamped) across the areas served by all three utilities. FEVI believes that its price competitiveness with electricity will become more challenged in the future once the Revenue Stabilization Deferral Account (RSDA) has been drawn down.

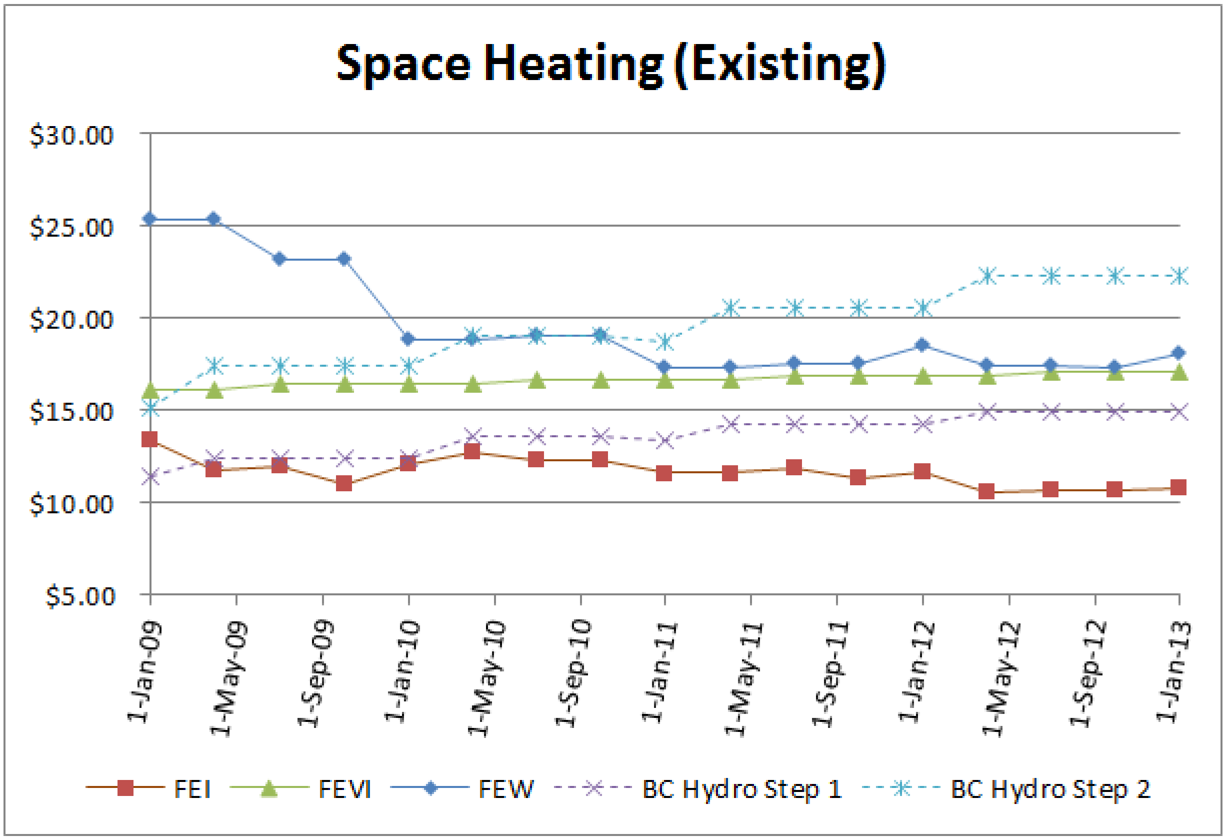
Figure 9 shows the space and water heating rate (cost $/GJ) comparisons as of January 2013.

10.1 Please expand Figure 9 for each year from 2009 to show the comparisons between gas and electricity rates of space and water heating.

Response:

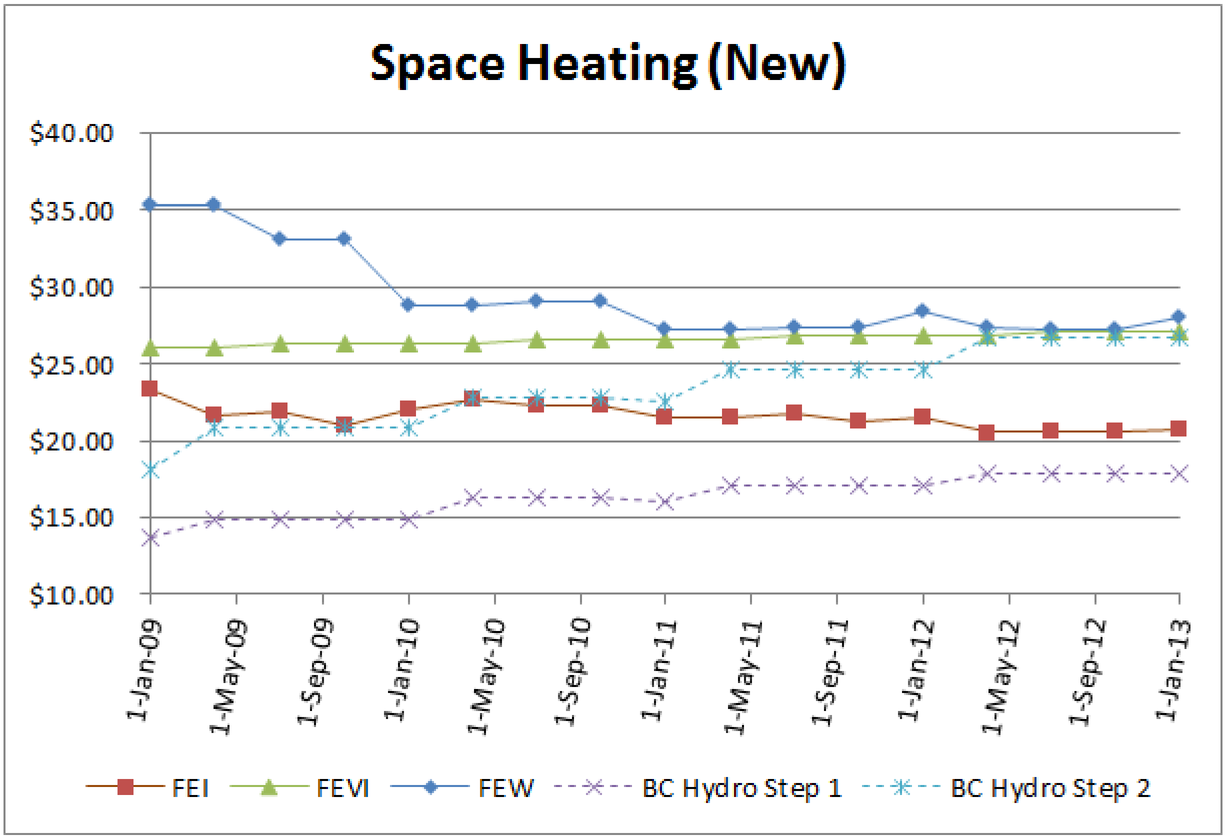
Figures 1 to 4 below illustrate the expanded space and water heating rate ($/GJ) comparisons from January 2009 to January 2013. All rates are based on 95 GJ/year consumption for comparison purpose. In summary, both FEVI and FEW are less competitive than the benchmark (FEI) when compared to BC Hydro rates for space and water heating applications for all customers (existing and new).

1 **Figure 1: Burner Tip Space Heating (Existing) Rate ($/GJ) Comparisons**

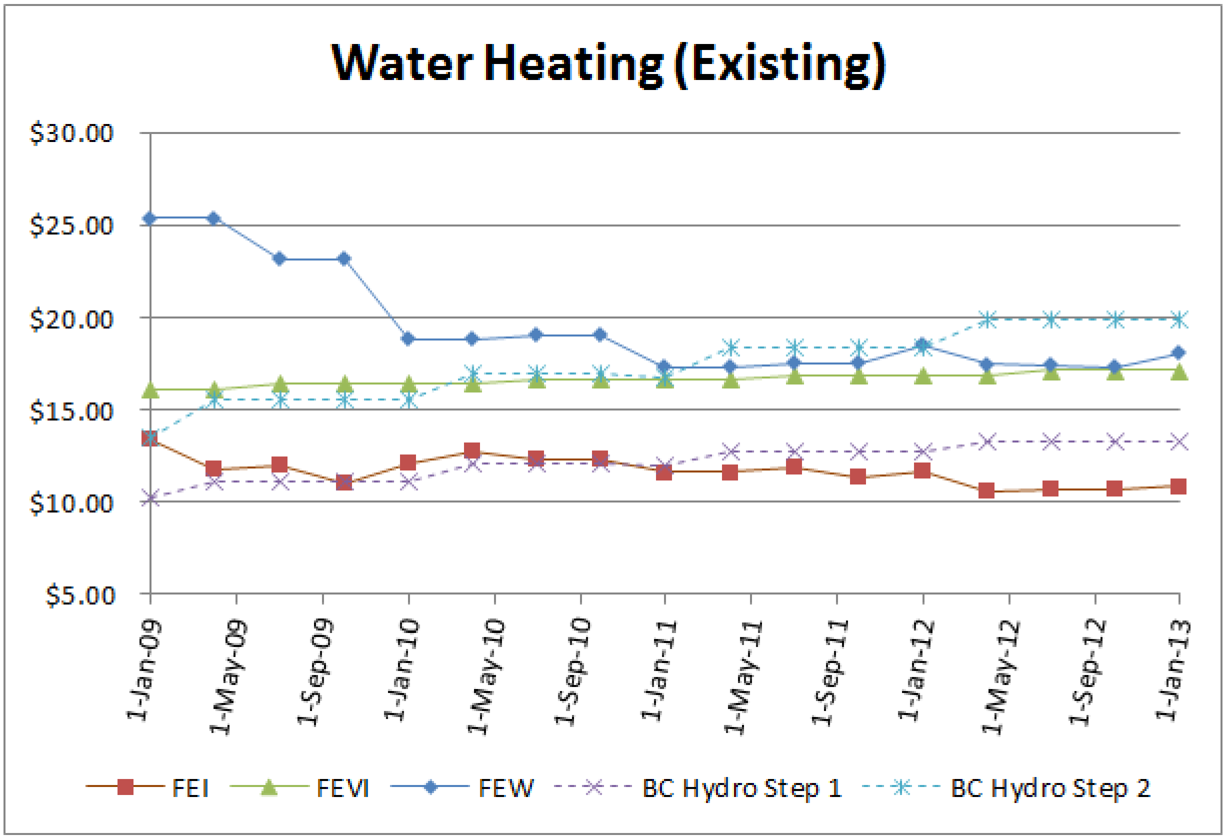


2

Figure 2: Burner Tip Space Heating (New) Rate ($/GJ) Comparisons

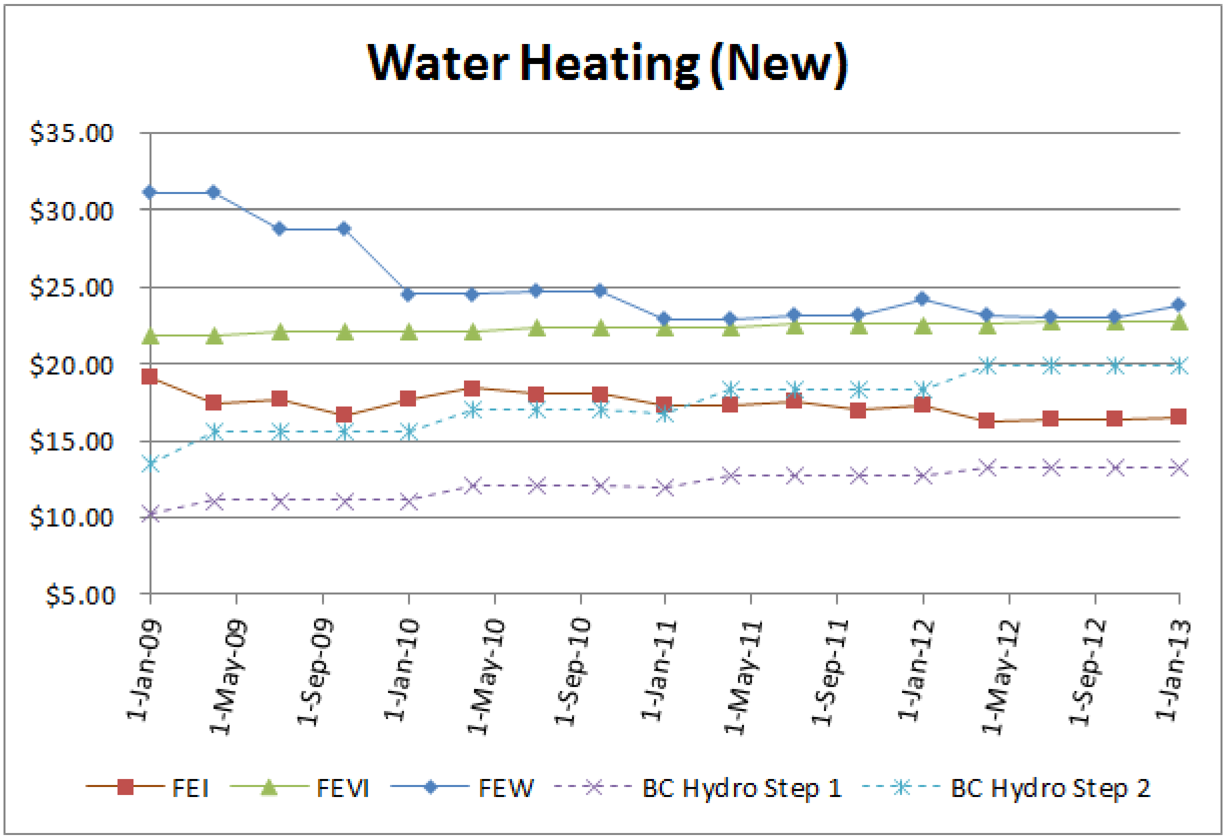


1 **Figure 3: Burner Tip Water Heating (Existing) Rate ($/GJ) Comparisons**



2

Figure 4: Burner Tip Water Heating (New) Rate ($/GJ) Comparisons



10.2 Please provide comparisons between FEVI and FEW rates versus Step 2 and Step 1 electricity rates, in terms of commodity market price changes and throughput, similar to Exhibit B1-24, BCUC IR 151 and IR 152 in the GCOC Stage 1 proceeding.

Response:

As stated in the response to BCUC IR 2.151.1 as part of the Stage 1 GCOC Proceeding, the FBCU do not agree that this kind of calculation provides a basis to suggest that the FEU's business risks have decreased. They ignore the effects of the other differences between providing for customers' thermal energy requirements using natural gas vs. electricity, such as the higher upfront capital costs of natural gas equipment and other factors that were described in detail in the response to BCUC IR 1.97.1. Commodity prices and the differential between natural gas and electricity rates are only one factor impacting the competitiveness of natural gas in BC relative to electricity. Furthermore, this analysis does not include the carbon tax applicable to natural gas and not electricity (approximately $1.50/GJ) or the higher capital costs for natural gas versus electricity applicable for new equipment. Finally, it is the change in the total burner tip rate that is relevant to the analysis, as the commodity charge cannot be viewed in isolation without consideration of the impacts to the delivery component.

The analysis that was provided in response to BCUC IR 2.151.1 and 2.152.1.1 modeled scenarios of assumed throughput loss for FEI of (i) 50 percent, (ii) 25 percent, (iii) 10 percent, and (iv) zero percent to achieve a residential commodity price that would be required to equate the combined natural gas rate to the BC Hydro RIB Step 1 or Step 2 rate at 60% and 90% efficiency. The 2013 residential rates for FEVI are currently set at $16.461/GJ and for FEW at $17.593/GJ. FEVI's rates are set below the cost of service. BC Hydro Residential Step 1 Rates are $12.083/GJ at 60% efficiency and $18.125 at 90% efficiency. As a result, FEVI and FEW have not modeled scenarios that incorporate a loss of throughput since their rates are already set at a level comparable to BC Hydro, and any loss in throughput would drive their rates to be at or above BC Hydro's.

FEI also provided tables in response to BCUC IR 2.152.1 calculating the natural gas throughput that would need to be lost to drive FEI's distribution margin up so that natural gas rates would become equal to BC Hydro's Step 1 electric rates at 2009 and today's rates, under both 60% and 90% efficiency scenarios. Since FEVI's and FEW's existing rates are already above the BC Hydro Step 1 rate at 60% efficiency in both 2009/2010 and 2012, no analysis of the throughput sensitivity has been provided for that scenario.

The following tables show the calculations and assumptions used to determine how much natural gas throughput would need to be lost to drive FEVI's derived margin and FEW's margin up so that natural gas rates would become equal to BC Hydro's Step 1 electric rates at 2009 (2010 for FEW as this was the first full year on natural gas rates) and 2013's rates at 90% efficiency.

As shown in Table 1, for the FEVI scenario where the natural gas thermal efficiency vs. electricity is 90%, the total rate increase required in 2013 to equate to the BC Hydro Step 1 rate is $1.66/GJ while the equivalent decrease in 2009 is $1.54/GJ (Line 12). This decrease was applied through the delivery margin but could also have been shown as a reduction to the commodity costs to achieve the same results. The table shows that FEVI's natural gas throughput would have to increase by 33% based on 2009's natural gas and Step 1 electricity rate to decrease the rate as requested in the question. The same calculation was applied to 2013's natural gas rates and RIB Step 1 rate but it would require a decrease of 17% of throughput to achieve the same result (because the natural gas rate is lower than the electric rate in 2013).

Table 1: Throughput Decrease Required to Increase FEVI's Distribution Margin and Overall Natural Gas rates to the RIB Step 1 (based on 90% Efficiency for Gas)

Line			Residential 2013	Residential 2009
1	Rates			
2	BC Hydro Step 1 ($/GJ) - 90% Efficiency for Natural Gas	As at April 1, 2013 and July 1, 2009 Converted to $/GJ	18.125	14.925
3				
4	FEVI Residential Rates ($/GJ)			
5	Residential Commodity embedded in Energy Charge	Weighted average 2013 and 2009	5.980	8.098
6	Residential Delivery porton of Energy Charge [1]		8.345	6.227
7	Residential Daily Basic Charge [2]	As at January 1, 2013 and 2009	2.136	2.136
8				
9				
10	Volumetric Delivery Rate Needed	Line 2 - Line 5 - Line 7	10.01	4.69
11	Existing Volumetric Delivery Rate	Line 6	8.345	6.227
12	Increase in Delivery Rate Required	Line 10 - Line 11	1.66	(1.54)
13				
14	Approved Volumetric Residential Delivery Margin ($000s)	Line 11 x Line 18	38,186	31,862
15				
16	Throughput Required at Revised Volumetric Delivery Rate(TJ)	Line 14 / Line 10	3,815.1	6,791.7
17				
18	Existing Throughput (TJ) [3]		4,575.9	5,116.8
19	% of Existing Throughput	Line 16 / Line 18	83%	133%
20				
21	Throughput that would need to be lost (TJ)	Line 18 - Line 16	**760.8**	**(1,674.9)**
22	Throughput that would need to be lost (%)	1 - Line 19	**17%**	**-33%**
23				
24	Notes:			
25	[1] Embedded delivery margin is calculated as approved Energy Charge less Cost of Gas embedded in 2013 and 2009 approved rates			
26	[3] Calculated as approved daily basic charge of $0.345 per day x 365.25 days / avg Residential Vancouver Island customer use rate of 59 GJs			
27	[3] FEVI Rate Schedule 1 Residential Volumes as approved in 2012/2013 RRA and 2009 RRA			
28				
29	Assumptions:			
30	-No loss in customer counts or basic charges. All change was based on customer use rate decreases			

As shown in Table 2, for the FEW scenario where the natural gas thermal efficiency vs. electricity is 90%, the total rate increase required in 2012 to equate to the BC Hydro Step 1 rate is 1.32/GJ while the equivalent decrease in 2009 is $2.737/GJ (Line 13). This decrease was applied through the delivery margin but could also have been shown as a reduction to the commodity costs to achieve the same results. The table shows that FEW's natural gas throughput would have to increase by 32% based on 2010's natural gas and Step 1 electricity rate to decrease the rate as requested in the question. The same calculation was applied to 2013's natural gas rates and RIB Step 1 rate but it would require a decrease of 10% of throughput to achieve the same result (because the natural gas rate was lower than the electric rate in 2013).

Table 2: Throughput Decrease Required to Increase FEW's Distribution Margin and Overall Natural Gas rates to the RIB Step 1 (based on 90% Efficiency for Gas)

Line			Residential 2013	Residential 2010
1	Rates			
2	BC Hydro Step 1 ($/GJ) - 90% Efficiency for Natural Gas	As at April 1, 2013 and July 1, 2010 Converted to $/GJ	18.125	16.174
3				
4	FEW Residential Rates ($/GJ)			
5	Residential Midstream	As at January 1, 2013 and 2010	0.935	1.043
6	Residential Commodity	Weighted average 2013 and 2010	3.445	5.554
7	Residential Delivery (excluding Riders) [1]		11.422	11.314
8	Residential Daily Basic Charge [2]	As at January 1, 2013 and 2010	1.000	1.000
9				
10				
11	Volumetric Delivery Rate Needed	Line 2 - Line 5 - Line 6 - Line 8	12.75	8.58
12	Existing Volumetric Delivery Rate	Line 7	11.422	11.314
13	Increase in Delivery Rate Required	Line 11 - Line 12	1.32	(2.737)
14				
15	Approved Volumetric Residential Delivery Margin ($000s)	Line 12 x Line 19	2,706	2,347
16				
17	Throughput Required at Revised Volumetric Delivery Rate(TJ)	Line 15 / Line 11	212.3	273.6
18				
19	Existing Throughput (TJ) [3]		236.9	207.4
20	% of Existing Throughput	Line 17 / Line 19	90%	132%
21				
22	Throughput that would need to be lost (TJ)	Line 19 - Line 17	**24.6**	**(66.2)**
23	Throughput that would need to be lost (%)	1 - Line 20	**10%**	**-32%**
24				
25	Notes:			
26	[1] Delivery margin on which approved rates set			
27	[2] Calculated as approved daily basic charge of $0.2464 per day x 365.25 days / avg Residential Whistler customer use rate of 90 GJs			
28	[3] FEW Rate Schedule 1 Residential Volumes as approved in 2012/2013 RRA and 2010 RRA			
29				
30	Assumptions:			
31	-No loss in customer counts or basic charges. All change was based on customer use rate decreases			

11.0 Reference: Exhibit B1-71, Tab A, pp. 3, 18

Revenue Surplus Deferral Account – FEVI

FEVI's rates are expected to increase in the near term once FEVI uses the remaining surplus in the Revenue Surplus Deferral Account (RSDA) to offset the rate impact of the elimination of the Provincial royalty revenues. The higher rates present a much greater competitive challenge for FEVI and FEW, as compared to FEI.

Based on FEVI's approved cost of service for 2013, an overall burner tip impact of between 8 percent and 25 percent is required (all else equal) in order to compensate customers for the loss of the royalty revenue amounts. A rate change of this magnitude will further erode FEVI's competitive position.

11.1 Please show the actual RSDA balance for each year from 2009 and show the forecast RSDA balance for 2013. Please include any calculations and assumptions as appropriate.

Response:

The Commission approved the creation of the RSDA account effective January 1, 2010. The following table summarizes the actual RSDA balance (net of tax) as of December 31 each year from 2010 to 2012, as well as the forecast balance for December 31, 2013:

RSDA Year End Balance ($ 000)	2010	2011	2012	2013P
Net of Tax Balance	$35,281.9	$63,830.6	$74,641.1	$71,279.6

*Excludes Interest Accumulated

11.1.1 Will FEVI apply for a rate increase immediately if the RSDA surplus is zero?

Response:

Once the RSDA balance is depleted, and in the absence of approval for amalgamation and the adoption of common rates or other material change in FEVI's circumstances, it can be reasonably assumed that FEVI will need to apply for a rate increase. At this point, the exact timing of the increase is uncertain but it will be dealt with in a future application should amalgamation and adoption of common rates not be approved upon reconsideration. Please refer to the response to BCUC FEVI-FEW IR 1.11.3.

11.2 Please confirm, or clarify, that FEVI rates are frozen until December 31, 2013. Please provide the information related to the date and the background that led to FEVI's rates being frozen.

Response:

Confirmed, FEVI rates are frozen until December 31, 2013. The basis for the rate freeze originated several years ago.

Recognizing that the provincial Royalty Revenues would be discontinued at the end of 2011, the 2010-2011 FEVI Revenue Requirements and Rate Design Application recommended and the Commission approved that rates be frozen for 2010 and 2011 for core market customers by Order G-140-09 issued on November 26, 2009. The surplus revenue that resulted from this rate freeze was captured in a deferral account called the RSDA. The RSDA was intended to accumulate revenue that would later be used to offset the loss of Royalty Revenues and mitigate the impact of forecasted rate increases.

The FEU 2012-2013 RRA further proposed that FEVI rates remain unchanged for 2012 and 2013. This rate freeze would ensure continued rate stability for Vancouver Island customers, and would allow sufficient time to implement an appropriate longer term solution to protect Vancouver Island customers against potential future rate increases. The rate freeze for FEVI's 2012 and 2013 rates was approved by Order G-44-12 on April 12, 2012.

11.2.1 For those years that FEVI rates are frozen, does that mean FEVI customers are not subject to any volatility of the natural gas commodity price as opposed to quarterly gas cost reviews of FEI?

Response:

Yes, for those years that FEVI rates are frozen, FEVI customers are not immediately subject to volatility in natural gas prices. Currently, the variance between the approved and forecast cost of gas for FEVI customers is captured in the Gas Cost Variance Account (GCVA). The balance in the GCVA is amortized into the cost of service, and therefore affects the balance in the RSDA (which captures differences between the revenues collected and the actual cost of service, other than O&M). For example, an increase in gas costs would result in a debit balance in the GCVA which would have the effect of increasing the cost of service and drawing down the

RSDA credit balance. This reduces the amount of RSDA available for rate mitigation and will result in an earlier increase to FEVI's rates than if gas costs had remained flat, all else equal. FEVI's 2013 Second Quarter Report on the GCVA and RSDA indicated a forecast GCVA deficit of approximately $2.9 million as of December 31, 2013.

11.3 With the best information available at this point, what is the likelihood that FEVI will increase customer rates and when will the rate increase be effective?

Response:

The FEU are currently involved in a Reconsideration Process for the Common Rates, Amalgamation and Rate Design Application. The Application involves implementation of common rates across FEI, FEVI and FEW, which is the proposed solution to the impending rate increases for FEVI. If approved, FEVI would adopt FEI's rate structure and implement common rates, therefore FEVI's customers would not face increased rates as noted in the preamble to the question.

In the absence of an approval of the amalgamation and adoption of common rates, or other material change in FEVI's circumstances that would address the higher effective rates faced by FEVI customers, FEVI anticipates that the RSDA balance would be depleted by 2020. Once depleted, rates would increase approximately 15% that year, and approximately 2% annually thereafter. The actual rate increases would depend on a number of factors, including an analysis of the options available to phase in the rate increase, as well as BCUC approval of the forecasted rate increases. In this analysis, FEVI's ROE is assumed to be 10% and its equity percentage is assumed to remain at 40%. Since a final decision in Stage 2 of the Generic Cost of Capital Proceeding remains outstanding, FEVI has not varied from these percentages.

The following table summarizes the rate increases forecast for FEVI based on utilization of the RSDA balance to mitigate rate increases:

Line	Assumptions	2013 Approved	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	Incremental Delivery Margin Increase		3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
2	Incremental Commodity Cost Increase		10%	10%	5%	5%	5%	2%	2%	2%	2%	2%
3	Cumualtive Tax Rate Increase compared to 2013		1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
4												
5												
6		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
7		Approved	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
8												
9	Annual Revenue Deficiency (Surplus)											
10	Delivery Margin	129,058	132,930	136,918	141,025	145,256	149,614	154,102	158,725	163,487	168,391	173,443
11	Cost of Gas	70,924	78,016	85,818	90,109	94,614	99,345	101,332	103,359	105,426	107,534	109,685
12	Income Tax Changes	-	582	582	582	582	582	582	582	582	582	582
13		199,982	211,529	223,318	231,716	240,453	249,541	256,016	262,666	269,495	276,508	283,711
14	Less: Forecast Revenue at Existing Rates	(195,727)	(202,819)	(210,621)	(214,912)	(219,417)	(224,148)	(226,135)	(228,162)	(230,229)	(232,337)	(234,488)
15	Forecast Annual Deficiency (Surplus)	4,255	8,709	12,697	16,805	21,035	25,393	29,881	34,504	39,266	44,171	49,223
16	RSDA	(4,255)	(8,709)	(12,697)	(16,805)	(21,035)	(25,393)	(29,881)	(465)	-	-	-
17	Net Annual Deficiency (Surplus)	-	-	-	-	-	-	-	34,039	39,266	44,171	49,223
18												
19	**Approximate Rate Increase (Decrease), %**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**14.9%**	**17.1%**	**19.0%**	**21.0%**
20	**Effective Rate**	**15.725**	**15.725**	**15.725**	**15.725**	**15.725**	**15.725**	**15.725**	**18.071**	**18.407**	**18.715**	**19.026**
21												
22												
23	RSDA Forecast											
24	Opening RSDA Balance, net of tax	(77,773)	(76,867)	(72,533)	(65,081)	(54,328)	(40,087)	(22,162)	(348)	-	-	-
25	Annual (Surplus)/ Deficiency	4,255	8,709	12,697	16,805	21,035	25,393	29,881	465	-	-	-
26	Add: Interest on Balance	(3,047)	(2,853)	(2,626)	(2,273)	(1,790)	(1,170)	(404)	5	-	-	-
27	Less: Rate Rider drawdown		-	-	-	-	-	-	-	-	-	-
28	Less: Tax	(302)	(1,523)	(2,618)	(3,778)	(5,004)	(6,298)	(7,664)	(122)	-	-	-
29	Closing RSDA Balance, net of tax	(76,867)	(72,533)	(65,081)	(54,328)	(40,087)	(22,162)	(348)	-	-	-	-
30												
31	Tax Rate	25.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
32	Closing RSDA Balance, before tax	(102,489)	(98,018)	(87,947)	(73,416)	(54,172)	(29,949)	(470)	-	-	-	-

11.3.1 Are FEVI's rates expected to be separately charged for components of delivery and commodity or would the components be combined?

Response:

At this time, the Reconsideration Process is before the Commission. In the event that the Amalgamation request is approved, common rates will be implemented for FEVI, FEW and FEI, and FEVI customers will adopt FEI's rate structure consisting of a basic, commodity, midstream and delivery charge. It is anticipated that amalgamated rates can be implemented effective January 1, 2015.

In the absence of approval for Amalgamation, it is anticipated that FEVI rates will still be unbundled, however the timing of the unbundling is currently unknown.

12.0 Reference: Exhibit B1-71, Tab A, p. 18

FEU 2012 Common Rates, Amalgamation and Rate Design, Exhibit B-9, IR 58.0

FEVI Royalty Revenue – FEVI

In the FEU 2012 Common Rates, Amalgamation and Rate Design proceeding, FEU stated that FEVI faces the elimination of Royalty Revenues at the end of 2011 that have ranged from $17 to $43 million in recent years and cover approximately 15percent-25percent of the current cost of service.

Page 18 of Tab A of Exhibit B-71 states that FEVI's royalty revenues have ranged from $15 million to $49 million in recent years, which translate to approximately 6 percent to 23 percent of total operating revenue.

12.1 Please reconcile the difference or clarify which is the accurate amount.

Response:

Both statements are accurate but one reflects actual amounts recorded in the year while the other reflects amounts which relate to the year but may have been recorded in the following year. Each year, a true-up adjustment is applied to the prior years' royalty revenues. This difference results from an annual true-up adjustment between the aggregate quarterly royalty revenues received and the final annual calculation of royalty revenues receivable by the Province of British Columbia, which is recorded in the following year.

The 2012 Common Rates, Amalgamation and Rate Design Application indicated that royalty revenues ranged from $17 to $43 million in recent years. This is based specifically on the royalty revenues received from 2006 to 2010, and is evidenced in Appendix B-3 of that Application, which summarizes FEVI's Annual Report statistics from 2003 to 2010.

The GCOC Application in Tab A of Exhibit B-71 indicated that royalty revenues ranged from $15 million to $49 million in recent years. These amounts reflect the amounts that related to the specific year but were recorded in other years (they include the true-up adjustment the following year but exclude the prior year true-up made in the current year).

13.0 Reference: Exhibit B1-71, Tab A, p. 20

New Building Distribution and Capture Rates for 2011

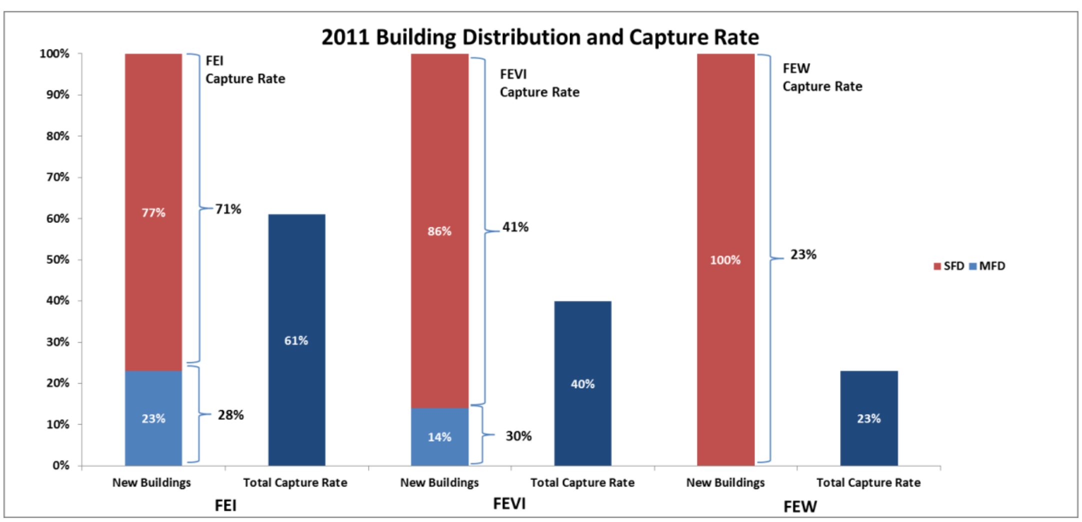
Figure 10 shows the new building distribution and capture rates for 2011 for FEI, FEVI, and FEW.

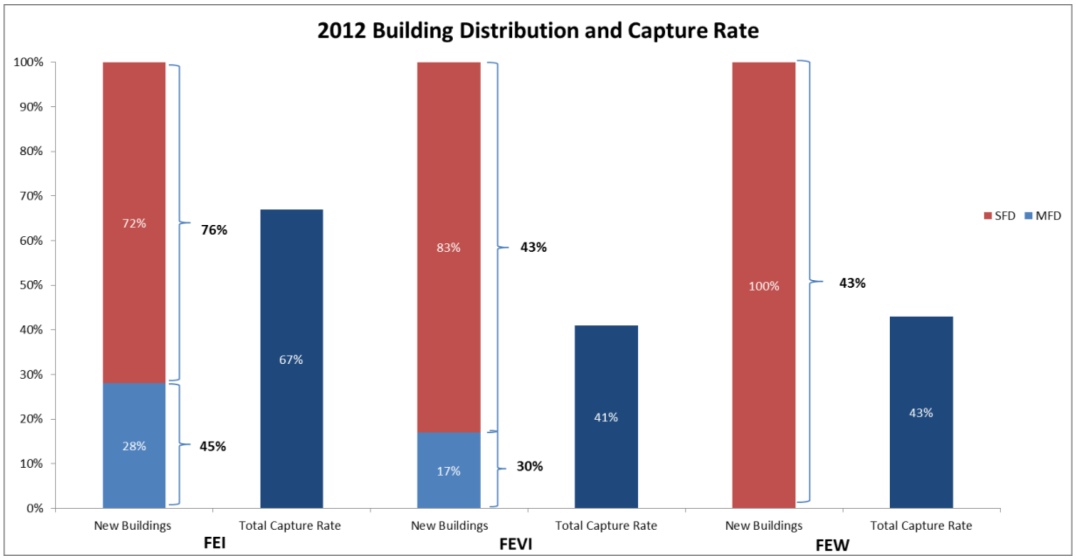
13.1 Please expand Figure 10 to show this information annually from 2009, and, if available, for 2012. Please also provide the supporting data in tabular format.

<u>Response:</u>

Capture rates prior to 2011 were analyzed on an aggregate level. Hence, no information is available for new building distribution prior to 2011. On aggregate, FEVI and FEI had been experiencing a decline in capturing new housing stock as gas customers. However the results for 2012 show a slight uptick in overall capture rates compared to previous years. While all segments of the new construction market continue to be challenging in the face of ever increasing competition, the multi-family segment represents the largest challenge. This is a result of builders and developers opting to install less expensive and easier to install equipment such as electric space heat and hot water.

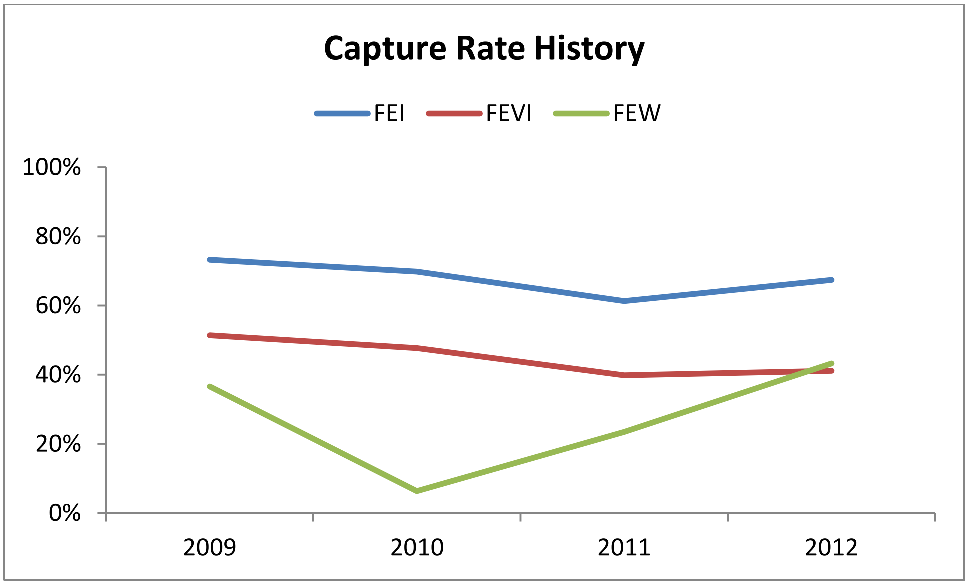
The following charts and table show the new building distribution and corresponding capture rates for 2011 and 2012, and demonstrate that FEVI and FEW continue to lag behind FEI in terms of capture rate on aggregate and by dwelling type (single-family and multi-family).





Summary Table of New Building Distribution and Capture Rate (2011 and 2012)												
	FEI				FEVI				FEW			
	2011		2012		2011		2012		2011		2012	
	MFD	SFD	MFD	SFD	MFD	SFD	MFD	SFD	MFD	SFD	MFD	SFD
Number of New Buildings	2,031	6,711	2,343	6,117	299	1,807	284	1,368	0	47	0	37
New Building Distribution	23%	77%	28%	72%	14%	86%	17%	83%	0%	100%	0%	100%
No. of Attachments	576	4,780	1,048	4,652	91	747	86	593	NA	11	NA	16
Capture Rate	**28%**	**71%**	**45%**	**76%**	**30%**	**41%**	**30%**	**43%**	**NA**	**23%**	**NA**	**43%**
Overall Capture Rate	**61%**		**67%**		**40%**		**41%**		**23%**		**43%**	

The chart and table below show the aggregate capture rate trend for FEI, FEVI and FEW between 2009 and 2012.



	2009			2010			2011			2012		
Utility	**New Completions**	**New Attachments**	**Capture Rate**	**New Completions**	**New Attachments**	**Capture Rate**	**New Completions**	**New Attachments**	**Capture Rate**	**New Completions**	**New Attachments**	**Capture Rate**
FEI	6,120	4,482	**73%**	8,215	5,731	**70%**	8,742	5,356	**61%**	8,460	5,700	**67%**
FEVI	1,999	1,028	**51%**	2,506	1,195	**48%**	2,106	838	**40%**	1,652	679	**41%**
FEW	104	38	**37%**	126	8	**6%**	47	11	**23%**	37	16	**43%**

13.2 Please comment whether or not there are any material changes in the new building distribution and capture rates since 2009 for FEVI and FEW as compared to FEI since 2009.

Response:

Please refer to the response to BCUC FEVI-FEW IR 1.13.1.

14.0 Reference: Exhibit B1-71, Evidence of FEVI and FEW, p. 4; Tab A, p. 24, Tab B, pp. 11-12

Supply Interruption Risk

"FEVI and FEW are further downstream of the FEI coastal transmission system so by this very nature their supply security concerns are greater than FEI. FEVI depends on a high pressure pipeline system that interconnects with the coastal transmission system. It traverses rugged terrain and includes marine crossings. FEW is further served by a single pipeline lateral that interconnects with FEVI's system at Squamish. A disruption on this pipeline lateral would disrupt service to FEW's entire customer base."

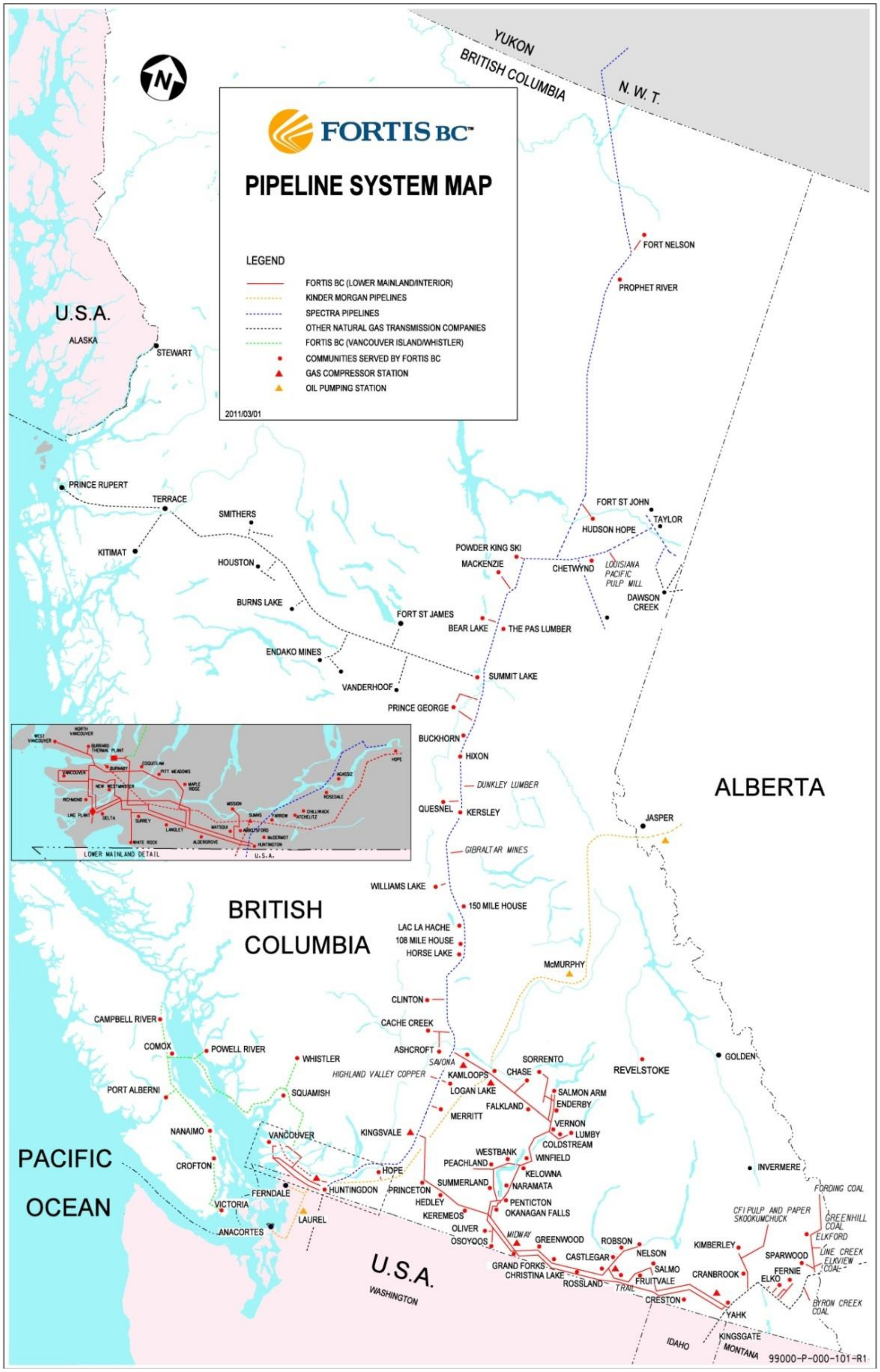
"These supply-related risks for FEVI and FEW remain essentially unchanged from what was assessed in the 2009 ROE and Capital Structure proceeding and 2009 FEW RRA."

14.1 Please provide a detailed map showing the location of the FEI, FEW, and FEVI pipeline system and compressor stations, the Mt. Hayes LNG facility, the Tilbury facility, the Westcoast Energy Inc. transmission pipeline, and FEI point of interconnection at Huntingdon.

Response:

Please refer to the map below showing the location of FEI's Coastal Transmission System, including the interconnection with Spectra's Westcoast's system at Huntingdon, and the referenced facilities for the other FEVI and FEW. Also included is a system map that provides an overview of FEI's transmission system, along with its interconnections with the Westcoast Mainline and Trans Canada Pipeline, and the FEVI system.

LEGEND
FEVI GAS PIPELINE
FORTISBC GAS PIPELINE
PIPELINES BY OTHERS
COMMUNITY SERVICED BY FORTISBC
COMPRESSOR UNITS
METER STATIONS
JOINT VENTURE MILLS
COGENERATION FACILITIES
I.C.P.
ELK FALLS
MS-25
MS-18
MS-17
CAMPBELL RIVER
POWELL RIVER
MS-16
CS-V4
TEXADA
ISLAND
MS-05
COURTENAY
COMOX
CUMBERLAND
MS-06
WHISTLER
MS-01
SQUAMISH
MS-15
CS-V3
SECHELT
PORT MELLON
MS-03
GIBSONS
STRAIT OF GEORGIA
QUALICUM
MS-07
PARKSVILLE
MS-08
MS-20
MS-19
PORT ALBERNI
NANAIMO
MS-09
MS-10
MS-21
HARMAC
LADYSMITH
MS-11
Mt.Hayes LNG
CS-V1
COQUITLAM
VANCOUVER
Tilbury LNG
CS-Langley
Westcoast Energy (Spectra)
HUNTINGDON
WHITE ROCK
SUMAS
CHERRY POINT
BELLINGHAM
CHEMAINUS
MS-22
CROFTON
DUNCAN
MS-12
MS-24
SHAWNIGAN LAKE
VANCOUVER ISLAND
MS-13
GREATER VICTORIA
CANADA
U. S. A.


FORTIS BC
PIPELINE SYSTEM MAP
LEGEND
FORTIS BC (LOWER MAINLAND/INTERIOR)
KINDER MORGAN PIPELINES
SPECTRA PIPELINES
OTHER NATURAL GAS TRANSMISSION COMPANIES
FORTIS BC (VANCOUVER ISLAND/WHISTLER)
COMMUNITIES SERVED BY FORTIS BC
GAS COMPRESSOR STATION
OIL PUMPING STATION
2011/03/01
YUKON
BRITISH COLUMBIA
N. W. T.
U.S.A.
ALASKA
ALBERTA
BRITISH COLUMBIA
PACIFIC OCEAN
U.S.A.
WASHINGTON
IDAHO
MONTANA
LOWER MAINLAND DETAIL
FORT NELSON
PROPHET RIVER
STEWART
PRINCE RUPERT
TERRACE
KITIMAT
SMITHERS
HOUSTON
BURNS LAKE
ENDAKO MINES
VANDERHOOF
FORT ST JAMES
FORT ST JOHN
TAYLOR
HUDSON HOPE
POWDER KING SKI
MACKENZIE
CHETWYND
LOUISIANA PACIFIC PULP MILL
DAWSON CREEK
BEAR LAKE
THE PAS LUMBER
SUMMIT LAKE
PRINCE GEORGE
BUCKHORN
HIXON
DUNKLEY LUMBER
QUESNEL
KERSLEY
JASPER
GIBRALTAR MINES
WILLIAMS LAKE
150 MILE HOUSE
LAC LA HACHE
108 MILE HOUSE
HORSE LAKE
McMURPHY
CLINTON
CACHE CREEK
ASHCROFT
SAVONA
HIGHLAND VALLEY COPPER
KAMLOOPS
LOGAN LAKE
SORRENTO
CHASE
REVELSTOKE
GOLDEN
SALMON ARM
ENDERBY
FALKLAND
MERRITT
VERNON
LUMBY
COLDSTREAM
WINFIELD
KELOWNA
WESTBANK
PEACHLAND
SUMMERLAND
NARAMATA
PENTICTON
OKANAGAN FALLS
KINGSVALE
HOPE
PRINCETON
HEDLEY
KEREMEOS
OLIVER
OSOYOOS
MIDWAY
GREENWOOD
GRAND FORKS
CHRISTINA LAKE
CASTLEGAR
ROBSON
NELSON
SALMO
FRUITVALE
ROSSLAND
TRAIL
CRESTON
KIMBERLEY
CRANBROOK
YAHK
KINGSGATE
INVERMERE
CFI PULP AND PAPER SKOOKUMCHUCK
FORDING COAL
GREENHILL COAL
ELKFORD
LINE CREEK
ELKVIEW COAL
SPARWOOD
FERNIE
ELKO
BYRON CREEK COAL
CAMPBELL RIVER
COMOX
POWELL RIVER
WHISTLER
SQUAMISH
PORT ALBERNI
NANAIMO
CROFTON
VANCOUVER
HUNTINGDON
FERNDALE
VICTORIA
ANACORTES
LAUREL
99000-P-000-101-R1

14.2 Have there been any interruptions since 2006 that have affected FEVI or FEW customers? Please briefly describe each instance including the time needed to restore service.

Response:

FEVI and FEW have not faced a significant system outage. Numerous incidents since 2006 have required careful management. The ability to manage these events can also be impacted by the time of year (i.e. overall loads on the system) and the operational status of the Island Generation facility at Elk Falls. FEVI has faced numerous potential service outages as illustrated by the following list of planned maintenance activities and unplanned incidents. A number of these incidents required a reduction of delivery volumes to the industrial customers that form the VIGJV, however to date FEVI had been able to manage these interruptions to maintain sufficient service levels to meet the VIGJV's firm contract demand.

- April 2007 - boulders fell onto FEVI right-of-way in the Seymour watershed. A precautionary pressure reduction was required which reduced the delivery capacity of the system, although no restriction was imposed on FEVI's customers.
- September 2007 - a section of transmission pipeline required relocation near Ladysmith. The Joint Venture's Crofton mill was held to firm for 12 hours; Western Forest Industries in Ladysmith town was required to move off process loads for the same 12 hours.
- November 2008 - Huntingdon station was forced to shut in following an incident during a repair and maintenance activity. The V1 compressor station was shut-in and the Joint Venture held to firm contract for approximately 4-5 hours and service to Island Generation facility reduced to the equivalent of 33 mmcfd for 5 hours.
- January 2011 - repairs were required for Unit 3 at the V1 compressor station. The VIGJV mills were held to authorized nomination for one day. The Island Generation facility was not operating.
- June 2012 - a panel upgrade at the V1 compressor station required a planned shutdown for five days. Load reductions were required and FEVI prearranged with BC Hydro not to request service for the Island Generation facility andthe VIGJV was held to firm contract demand.
- September 2012 - linepack on the Spectra T-South mainline was well below normal and FEI and FEVI was requested to reduce delivery. The VIGJV was held to authorized nomation for the day. The Island Generation facility was not operating.

In addition, to the above events that required temporary load reductions, FEVI faced a number of transmission pipeline incidents that arose from pipe exposure and washouts. While contingency planning helped to prevent service interruptions, they had the potential to significantly affect delivery to customers. These incidents include the following:

- Calvin Creek (1993) - creek channel movement threatening DOC. Creek banks reinforced with riprap. About a week to repair. No service interruptions.
- Indian River washout (1994) - pipeline exposed for 35m parallel to the river. No service interruptions. About three weeks to repair.
- Qualicum River washout (1994) - same weather event as the Indian River washout exposed approximately 40 feet of the Pt. Alberni lateral. No service interruptions but possible pressure reduction. About a month to repair.
- Tsolum River washout. (1995) - river switched channels exposing the pipeline. No service interruptions. About a month to repair.
- Dove Creek washout (1996) - small section of pipeline exposed. No service interruptions. About one month to repair.
- Rainy River washout (1997) - small section of pipe exposed for approximately 10 feet. One day to repair. No service interruptions.
- Hixon Creek washout (2003) - pipeline exposed in creek. Temporary line installed on the bridge deck. No service interruptions. Installed bridge crossing the following year.
- Dakota Creek washout (2003) - small water run moved across the pipeline compromising the depth of cover. Three days to repair. No service interruptions.
- Haslam Creek (2006) - creek channel movement threatening DOC. Creek banks reinforced with riprap and DOC reinstated with concrete matting. About three days to repair.
- Bonnal Creek (2007) - creek channel movement threatening DOC. A rock weir was installed downstream of pipeline to protect DOC. About a week to repair. No service interruptions.
- Wilfred Creek (2008) - river channel threatening to expose pipeline. Bank of river reinforced with riprap. About a week to repair. No service interruptions.
- French Creek (2009) - creek channel movement threatening DOC. Pipeline DOC reinstated with concrete matting. About one week to repair. No service interruptions.

- Quad Creek (2009) - pipeline exposed in creek. No service interruptions. Pipeline DOC reinstated.

The Whistler Lateral connecting from Squamish to supply FEW has not experienced any service interruption since its operation beginning in 2009. However, the Whistler Lateral, located for the most part adjacent to the Sea-to-Sky Highway, remains as a potential single point failure subject to damage from third parties and rock falls and slides.

From a transmission perspective, the FEVI system, and lateral serving FEW, is exposed to interruption risk given the rugged terrain and numerous creeks and major river crossings it traverses. This requires both FEVI and FEW to maintain a high level of contingency planning and incident management to manage interruption risk. Monitoring, inspection, and adequate maintenance are key to keeping the system in service and avoiding a significant outage given this circumstance.

From a distribution perspective, FEVI and FEW need to manage a considerable number of incidents in a typical year that involve third parties hitting distribution lines and that then cause outages. On average from 2006 to 2012 FEVI needed to manage 220 line hits each year across its distribution territory. These line hits involved an average outage of 1.6 hours each and affected an average of 450 customers each. FEW, given its much smaller size, faced an average of 9 line hits each year, which involved an average outage of 1.7 hours each and affected an average of 14 customers each.

15.0 Reference: Exhibit B1-71, Tab A, p. 24; Tab B, p. 12

Commission Letter L-21-13

Supply Interruption Risk – Mt. Hayes LNG Facility

"FEVI's Mt Hayes LNG storage facility is located on FEVI's system at Ladysmith. Construction of the facility was approved by the Commission in 2008, and it was put into service in April 2011. The primary purpose of the facility is to provide peaking gas supply and system capacity to both FEI and FEVI during periods of high demand. However, the location of the facility on FEVI's system also provides FEVI some ability to maintain critical loads on its system in the event of a short term pipeline disruption."

"FEVI's pipeline has three twinned submarine crossings, which are approximately 12.3 km, 10.9 km, and 23.7 km in length, respectively. While the probability of a total failure of a submarine crossing is small, there is some additional security of supply risk associated with the difficulty of repairing a submarine crossing to maintain uninterrupted service once the reserves in Mt. Hayes have been depleted."

"These supply-related risks for FEVI and FEW remain essentially unchanged from what was assessed in the 2009 ROE and Capital Structure proceeding and 2009 FEW RRA."

In her Evidence, Ms. McShane states that the Mt. Hayes LNG facility improves the security of supply, but is a short term solution in the event of a significant failure on the pipeline. With FEVI's dependence on the marine crossing, it is exposed to higher supply disruption risk than FEI.

On March 22, 2013,FEVI sought approval of the level of the Supplemental LNG Service (Put) that FEVI intends to provide to FEI from April 1, 2014 to March 31, 2015, under the terms of the Storage and Delivery Agreement between FEVI and FEI.

In Letter L-21-13, the Commission noted:

> "FEVI submits that maintaining the Put level at 35 TJ/d of daily withdrawal capability and 350 TJ of total capacity (equivalent to 65 percent of FEVI's primary Mt. Hayes LNG Storage capacity) for a one-year term commencing April 1, 2014 and ending March 31, 2015, would optimize the cost effectiveness of FEVI's portfolio while ensuring consistency with the objectives of its Annual Contracting Plan and other considerations."

15.1 Please indicate approximately how many days (summer and winter) Mt. Hayes would be able to provide emergency service to FEVI firm (non industrial) customers in case of a disruption of the twin submarine crossings. Please confirm that each of the twin pipelines was sized to meet total FEVI firm loads so that both pipelines would have to be ruptured to cause a supply shortage.

Response:

The Mt. Hayes LNG Storage Facility could provide enough on-island supply to meet roughly 30 days of core market demand with curtailment of all firm transportation services during an average winter period; and roughly 65 days of core market demand with curtailment of all firm transportation services during an average summer period in case of a disruption of the twin submarine crossings.

FEVI confirms that each of the twin submarine crossings was designed and constructed to meet total FEVIs firm load.

15.1.1 What is the normal repair time of submarine pipelines to restore service?

Response:

Generally, several months to a year would be required to plan, design, and to secure the material and labour resources needed to carry out a repair of a submarine pipeline. The long lead time needed to prepare for a repair of a submarine pipeline is the reason why each of TGVI's marine crossings is twinned.

A simultaneous outage of all of the twinned marine crossings would result in a long term service interruption, as a temporary bypass of the marine crossing is not practical and LNG supply from Mt. Hayes supply would not be sufficient.

15.2 Based on the availability of Mt. Hayes since April 2011, why would the security of supply risks for FEVI not decrease relative to FEI?

Response:

The reduction in the security of supply risk that was realized since the initial operation of Mt. Hayes in April 2011 was already known at the time of the 2009 ROE and Capital Structure proceeding. The facility had been approved by the Commission in 2008. There has been no additional reduction in supply risk for FEVI since that time.

Within this context, it is important to consider that FEVI remains subject to single point of failure risks. While Mt. Hayes provides short term relief from a long term supply disruption, this relief is limited depending on tank levels, time of year, and location of the disruption on the system.

Please refer to the response to BCUC FEVI-FEW IR 1.15.2.1.

15.2.1 Would FEVI agree that the supply interruption risk of FEVI is now less risky as compared to 2009? If not, why not?

Response:

Yes, the supply interruption risk of FEVI is now less risky as compared to 2009 given the introduction of Mt. Hayes as an emergency supply in the event of FEVI pipeline disruption and supply outage from Huntingdon-Sumas hub. However, the facility had been approved by the Commission in 2008 and the risk reduction was already known in 2009 when the Commission last determined FEVI's cost of capital. See, for instance, page 95 of the 2007 CPCN application for Mt. Hayes and the response to BCUC Panel IR 1.6.0 from the 2009 ROE and Capital Structure proceeding which stated:

> *"The Mt. Hayes LNG facility is currently being constructed which will provide a degree of supply interruption protection but failure of the marine crossing pipeline segments would likely result in prolonged supply interruption beyond the capacity of the storage facility."*

15.3 Please confirm that the FEI gas portfolio includes gas supply to FEW's customers.

Response:

Confirmed.

15.4 Please indicate approximately how many days (summer and winter) Mt. Hayes would be able to provide service to FEW in case of a disruption of a line break between Coquitlam and Squamish.

Response:

A line break on FEVI's transmission system between Coquitlam and Squamish, would disrupt supply for all of the loads on FEVI's system, including FEW and FEI's customers in Squamish. In this scenario the Mt. Hayes LNG Storage Facility could be required to satisfy the core market demand on Vancouver Island, the Sunshine Coast, Squamish and Whistler. Assuming the full curtailment to all firm transportation service to industrial customers, it could provide enough supply for approximately 25 days during an average winter period. Far fewer days would be available if a peak day or colder than normal spell of weather occurred during this period. During the average summer period roughly 60 days of core market demand could be supplied, also assuming the full curtailment to all firm transportation service to industrial customers.

15.4.1 Please indicate the normal repair time for such unplanned pipeline outage.

Response:

In the event of a major line break on FEVI's system excluding the marine crossings, a temporary repair using a bypass around the damaged section of the pipeline could be constructed within two to five days depending on the severity of the damage and remoteness of its location. This bypass could potentially be a smaller pipe size or be operated at a lower operating pressure to expedite service recovery, which would result in a reduction in throughput capacity. A permanent repair of a major line break would take considerable time in terms of months to plan, design, and to secure the material and labour resources needed. The actual repair could be completed within a two to five day period.

15.4.2 Is it true that the FEW and FEW gas portfolio is amalgamated? Wouldn't FEI's LNG tankers be able to serve FEW?

Response:

FEI's gas portfolio includes meeting the gas supply requirements for FEW. However, even if the gas portfolios were separate, FEI's LNG tankers could be used to mitigate disruptions on segments of FEW's distribution system, but would not be able to replace FEW's supply in the case of a transmission line failure.

FEI's two 12,500 USG (1.1 TJ) LNG road tankers, combined with the 0.5 TJ/d LNG vaporizer are designed to provide sufficient capacity to deliver emergency supply for only limited sections of natural gas distribution systems. As a result, this portable LNG supply is not sufficient to supply the total demand of FEW even at the lowest demand period during the summer months.

15.5 Based on the availability of Mt. Hayes since April 2011, why would the security of supply risks for FEW not decrease relative to FEI? Would FEW agree that the supply interruption risk of FEW is now less risky as compared to FEI since 2009? If not, why not?

Response:

The supply interruption risk of FEW has declined somewhat since Mt. Hayes came on line. However, the role of Mt. Hayes in helping to manage supply interruptions was already known when the Commission determined FEVI's and FEW's cost of capital. See page 95 of the 2007 CPCN application for Mt. Hayes and the response to BCUC Panel IR 1.6.0 from the 2009 ROE and Capital Structure proceeding. A relevant quote from the latter evidence is included in the response to BCUC FEVI-FEW IR 1.15.2.1.

While FEW's ability to manage a short term supply interruption has improved with availability of Mt. Hayes since 2011, Mt. Hayes will not reduce FEW's risk of supply interruption in the event of a rupture of the Whistler Lateral connecting the FEVI transmission system to FEW. As set out in the response to IR 1.15.4.2, portable LNG supply using Tilbury LNG road tankers and associated portable vaporizer are insufficient to provide supply to meet the total demand of FEW in the event of a major disruption.

16.0 Reference: Exhibit B1-71, Tab A, p. 24; Tab B, pp. 12-13

FortisBC Energy Utilities 2012-2013 Revenue Requirements & Natural Gas Rates, Exhibit B-22, BCUC IR 1.0

Supply Interruption Risk – FEW

"FEW is served by the pipeline lateral between Squamish and Whistler owned and operated by FEVI as part of its overall system. It thus faces similar risk of supply disruption as that of FEVI through the Coquitlam watershed, and also faces single point failure risk on FEVI's pipeline lateral between Squamish and Whistler. Furthermore, FEW does not currently have any on-system storage or LNG that can be used to maintain service in emergency situations (e.g., a disruption on FEVI's pipeline lateral)."

"These supply-related risks for FEVI and FEW remain essentially unchanged from what was assessed in the 2009 ROE and Capital Structure proceeding and 2009 FEW RRA."

In her Evidence, Ms. McShane states that FEW is also exposed to higher supply interruption risk than either FEI or FEVI, as it is dependent on the FEVI pipeline (connecting at Squamish) plus a single transmission line through rugged territory from Squamish to Whistler, with no storage on its system for emergency back-up. FEW has no marine crossing, but only has enough line pack to serve the system for a very short time in the event of a disruption on the pipeline.

Exhibit B-22 of the FortisBC Energy Utilities 2012-2013 Revenue Requirements & Natural Gas Rates:

> "… FEI currently owns two LNG tankers, both of which are kept in inventory at the Tilbury LNG facility available for service as required. Currently, the LNG tankers are used primarily for emergency response when LNG is required to be delivered and vaporized into the FEI delivery system in circumstances such as large scale service outages."

In its response to BCUC IR 1.1 in Exhibit B-22, it states:

> "The tanker can be transported by a semi-tractor to locations as required to provide LNG. The primary use of the tanker will be as a backup resource for system reliability and integrity in both planned and unplanned (emergency) outages. When FEI's gas lines are hit or when planned pipeline work is required that involves interrupting the flow of gas, the LNG tanker is used as an alternate natural gas supply source where the LNG is vapourized into the distribution system to maintain service to customers."

16.1 Please confirm that FEI currently owns two LNG tankers that are used as a backup resource for system reliability and integrity in both planned and unplanned outages, which would include servicing FEW in the case of line breaks.

Response:

Yes, FEI currently owns two LNG tankers and they are used as emergency portable supply for both planned and unplanned outages, which could include servicing FEW. However, as stated in the response to BCUC FEVI-FEW IR 1.15.4.2, the portable supply is designed to provide sufficient capacity to provide emergency supply only for sections of natural gas distribution systems. In the case of a line break of the Whistler Lateral to FEW, this portable LNG supply is not sufficient to supply the total demand of the FEW even at the lowest demand period during the summer months.

16.2 Please confirm that the second tanker was purchased in December 2010.

Response:

The second LNG road tanker was purchased in June 2010 and delivered to the Tilbury LNG facility in November 2010.

16.3 Please confirm that the second tanker has been available to respond to FEI gas delivery system emergencies and planned outages and as a back up to the other tanker, which such emergencies would include serving FEW customers.

Response:

Confirmed. As noted in the response to BCUC FEVI-FEW IR 1.15.4.2, the second LNG tanker along with the first LNG tanker and the portable LNG vaporizer are designed to provide sufficient capacity to provide emergency supply only for sections of natural gas distribution systems. These tankers are unable to meet total firm load requirements of either FEW or FEI in the event of a major system outage.

16.4 Suppose there's an unplanned pipeline outage from Squamish to Whistler, does FEW have access to the Tilbury LNG plant where FEI can use tankers to supply FEW customers? Is it not common practice in the natural gas utility industry to share such resources in emergency situations?

Response:

It is common practice in the natural gas utility industry to share resources through mutual aid agreements among neighbouring utilities in order be able to lend support in emergency situations. FEW does have access to the Tilbury LNG plant where FEI can use tankers to supply FEW customers. However, as set out in the response to BCUC FEVI-FEW IR 1.15.4.2, in the event of an unplanned pipeline outage from Squamish to Whistler, the portable LNG supply from the road tankers and vaporizer is not sufficient to satisfy the total demand of all FEW customers even on the lowest demand period during the summer months.

16.4.1 Please indicate how many days of supply (summer and winter) would FEW obtain by way of using tankers to transport gas from Tilbury to the FEW system to serve its customers?

Response:

As set out in the response to BCUC FEVI-FEW IR 1.15.4.2, in the event of an unplanned pipeline outage from Squamish to Whistler, the portable LNG supply from FEI's two road tankers and vaporizer is not sufficient to satisfy the total demand of all FEW customers even on the lowest demand period during the summer months. While FEI's road tankers would provide approximately three hours supply for an average winter day and nine hours supply for an average summer day, the portable vaporizer is not sufficiently sized to meet FEW's hourly demand even on a summer day.

16.5 Would FEW agree that there are well established alternatives to supply gas to FEW customers in the event of line break from the Coquitlam watershed to Squamish, and/or from Squamish to Whistler? E.g., LNG tankers from Tilbury or Mt. Hayes LNG to Whistler?

<u>Response:</u>

No, please refer to the responses to BCUC FEVI-FEW IRs 1.15.4.2, 1.16.1, 1.16.3, 1.16.4 and 1.16.4.1.

16.6 Based on the alternatives to supply gas in unplanned outages and since FEI now owns two LNG tankers, why would the supply-related risks for FEW remain essentially unchanged? Would FEW agree that the supply interruption risk of FEW is now less risky as compared to 2009? If not, why not?

<u>Response:</u>

For the reasons explained in the responses to BCUC FEVI-FEW IRs 1.15.4.2, 1.15.5, 1.16.1, 1.16.3, 1.16.4, and 1.16.4.1, today's supply-related risks for FEW remain unchanged from 2009.

17.0 Reference: Exhibit B1-71, Tab B, pp. 2, 7, 15

Historical Percentage Point Difference – FEVI and FEW

In her Evidence on page 2, Ms. McShane states that the historical five percentage point difference between the equity ratios of FEI and those of FEVI and FEW suggest, in isolation, an equity ratio for both of 43.5 percent.

The following information is based on past Decisions related to capital structure and ROE risk premiums:

Line No.	Company	2013 [1]	2012	2011	2010	July 2009	2009 [2]	2008	2007
1		**Allowed Company Equity Risk Premiums (bps)**							
2	FEI (Benchmark)	0	0	0	0	0	0	0	0
3	FEVI	50	50	50	50	50	70	70	70
4	FEW	75	50	50	50	50	50	60	60
5		**Allowed Common Equity Thickness**							
6	FEI (Benchmark)	38.5%	40%	40%	40%	35%	35%	35%	35%
7	FEVI	43.5%	40%	40%	40%	40%	40%	40%	40%
8	FEW	45%	40%	40%	40%	40%	40%	40%	40%
9	**Notes:**								
10	(1) Proposal of GCOC Proceeding Stage 2 for FEVI and FEW								
11	(2) 2009 Benchmark as per Letter L-55-08								

(Source: The Brattle Group Report, p. 50)

In her Evidence on page 7, Ms. McShane also states that for purposes of Stage 2 as regards FEVI and FEW, the focus is on how FEVI's and FEW's current business risks compare to those of FEI and whether there has been any material change in the relative business risks of FEVI or FEW as compared to FEI since 2009.

17.1 FEW is recommending a 6.5 percent differential above the FEI benchmark equity thickness and a 75 bps differential above the FEI benchmark allowed ROE, which makes the combined cost of capital the highest in its history relative to the benchmark utility. Please describe the main driver of the big differential relative to 2009.

Response:

Ms McShane indicates that the main driver of the differential was the determination that FEW is riskier than FEVI and that its common equity ratio and equity risk premium should reflect its higher risk. In other words, the main driver is the recognition of the risks that existed even in 2009, rather than a change in the relative risk as between FEI and FEW since 2009.

17.1.1 In Ms. McShane's view, is FEW currently the highest risk natural gas or electric utility in B.C.? Why or why not?

Response:

No. In Ms. McShane's opinion, Pacific Northern Gas Ltd. (PNG-West Division) and Pacific Northern Gas (N.E.) Ltd., Tumbler Ridge division face higher business risk than FEW, with key differentiating factors being higher market demand and throughput risk for the two PNG utilities.

17.1.2 Are there higher risk utilities in other Canadian jurisdictions? If so, please provide the names of those utilities and their allowed cost of capital.

Response:

Yes. Both Heritage Gas and Enbridge Gas New Brunswick are examples of Canadian utilities that are higher business risk than FEW. The allowed cost of capital for Heritage Gas is 8.94% comprised of a cost of debt of 7.25%, an ROE of 11% and a capital structure containing 45% equity and 55% debt. The allowed cost of capital for EGNB in 2012 was 8.23% comprised of a cost of debt of 6.04%, an ROE of 10.9% and a capital structure containing 45% equity and 55% debt.

18.0 Reference: Exhibit B1-71, Tab B, pp. 3-4

Credit Rating Outlook – FEVI

Evidence related to FEVI's deemed common equity ratio was last reviewed by the Commission during the 2005/2006 cost of capital proceeding, when FEVI's equity ratio was set at 40 percent, along with an equity risk premium of 70 bps.

In the 2009 CAP/ROE Decision, the Commission reduced FEVI's equity risk premium from 70 to 50 bps and confirmed FEW's equity risk premium at 50 bps. In that decision, because no changes to either FEVI's or FEW's equity ratios had been proposed in that proceeding, the Commission confirmed the previously approved 40 percent deemed common equity ratios.

18.1 When the Commission adjusted FEVI's equity risk premium in 2009, did that prompt any response from the credit agencies?

Response:

FEVI received no direct response from the Credit Agencies regarding the change in the equity risk premium resulting from the 2009 Decision. However, both ratings agencies did acknowledge the change in the overall ROE of FEVI in reports following the Decision. The reports were submitted to the Commission as part of the Minimum Filing Requirements. See the Moody's March 12, 2010 and the DBRS' November 15, 2010 reports.

18.1.1 If yes, please summarize their response and provide those reports.

Response:

Please refer to the response to BCUC FEVI-FEW IR 1.18.1.

18.1.2 If not, does Ms. McShane have any views as to why not?

Response:

In Ms. McShane's view, the muted nature of the response from the two debt rating agencies reflected the fact that the magnitude of the increase in ROE for FEVI due to the increase in the benchmark utility ROE was significantly larger than the reduction in the FEVI specific risk premium.

19.0 Reference: Exhibit B1-71, Evidence of FEVI and FEW, pp. 10-11; Tab D Moody's Credit Opinion

Credit Metrics

In the June 26, 2013 report, Moody's refers to FEVI's recent developments that include the phase-out of royalty revenues from the Province and a denied application to amalgamate operations with affiliates FEI and FEW.

The same report also refers to FEVI's allowed ROE having decreased to 9.25 percent as a result of the GCOC –Stage 1 Decision and notes that FEVI's capital structure and risk premium are currently under review in Stage 2.

According to the report, the key Moody's indicators for 2012 are as follows:

(CFO Pre-W/C + Interest)/Interest Expense	4.8x
(CFO Pre-W/C)/Debt	19.6%
(CFO Pre-W/C – Dividends)/Debt	17.7%
Debt/Book Capitalization	44.0%

19.1 Please provide the key indicators for FEVI in 2013 under the following scenarios. Please make explicit any assumptions used and show your calculations.

(a) Equity thickness 38.5percent, risk premium 50 bps

(b) Equity thickness 40.0 percent, risk premium 50 bps

(c) Equity thickness 42.0 percent, risk premium 50 bps

(d) Equity thickness 43.5 percent, risk premium 50 bps

<u>Response:</u>

Fiscal 2013 is yet finished so FEVI has applied the adjusted scenarios to the 2012 data on a retroactive basis:

Key Indicators	2012	Adjusted 2012 Scenarios			
	Actual	(a)	(b)	(c)	(d)
(CFO Pre-W/C +Interest)/Interest Expense	4.8x	4.6x	4.7x	4.9x	5.0x
(CFO Pre-W/C)/Debt	19.6%	18.3%	19.0%	20.1%	21.0%
(CFO Pre-W/C-Dividends)/Debt	17.7%	16.4%	17.1%	18.2%	19.0%
Debt/Book Capitalization	44.0%	45.3%	44.1%	42.4%	41.2%

20.0 Reference: Exhibit B1-71, Tab B, pp. 17, 22; GCOC Stage 1 Decision dated May 10, 2013, pp. 19-20

Consideration from other Canadian and United States Jurisdictions

In her testimony, Ms. McShane states:

> "An analysis of the differences between the allowed common equity ratios of small and large Canadian gas utilities and the absolute values of the small gas utilities' equity ratios indicates an equity ratio of approximately 45% for both FEVI and FEW.
>
> The allowed and actual equity ratios of U.S. gas utilities are appropriate benchmarks for both FEVI and FEW and point to equity ratios in the 50% to 52% range."

In the GCOC Stage 1 Decision with respect to the considerations from other Canadian jurisdictions, the Commission acknowledged the importance of considering the methodologies, approaches and regulatory principles related to other jurisdictions' decisions. However, the Commission did not accept that it was appropriate for results and values to be used for the purpose of calibration in B.C.

With respect to US data and decisions, the Commission accepted that while there are similarities between the two jurisdictions, the Panel did not accept that US data should be considered to be the same or necessarily be given equal weight as the data for Canadian utilities.

20.1 In light of the GCOC Stage 1 Decision, why should the Commission give weight based on the US gas utilities data that led to the conclusion that the common equity ratio should be in the 50 percent to 52percent range?

<u>Response:</u>

Ms. McShane provides the following response.

Moody's has a global methodology for rating gas and electric utilities and uses the same guidelines across borders. Moody's is comparing FEVI's business risk to other gas distributors globally, including U.S. gas distributors, not to just other Canadian gas distributors when it concludes that FEVI's high cost of service and small size cause its market position i.e., fundamental business risk, to be weaker than most gas LDCs. "Most LDCs" would include the U.S. gas distribution utilities, many of which Moody's rates and considers comparators to FEVI. In its Credit Opinion for FEVI dated June 26, 2013, Moody's explicitly compared FEVI to U.S. utilities on regulatory environment, concluding "We view the BC regulatory framework to be similar in its framework to a strong US jurisdiction, due to similar procedural and legal processes and supportive cost recovery features, including a forward looking test year, deferral accounting for certain costs and timely decisions from the commission."

20.2 If the equity ratios of FEVI and FEW were set respectively at 43.5 percent and 45 percent they would put them at the highest level of awarded equity ratios for small Canadian utilities. Please present the business profiles of FEVI, FEW, AltaGas Utilities, Heritage Gas, Enbridge Gas NB, Gazifère using Table 2 on page 6 of FEVI and FEW Evidence as template.

Response:

Please refer to Attachment 20.2 for the requested information.

21.0 Reference: Exhibit B1-71, Tab B, p. 17

Business Risk Comparison with Enbridge Gas NB, Gazifère, and Heritage Gas

In Table 2 on page 17 of her Evidence, Ms. McShane provided comparisons of the allowed cost of capital for smaller gas distribution utilities such as Enbridge Gas New Brunswick (EGNB), Gazifère, and Heritage Gas.

21.1 Please provide the following data for the above three utilities:

21.1.1 Existing burner tip rate comparison between each utility and its electric equivalent in the jurisdiction under which it operates.

Response:

EGNB reports a total cost for August 2013 of $21.17 per GJ for customers in the Small General Service rate class, which includes the delivery charge and a gas cost of $9.50 per GJ, but excludes the monthly $16 customer charge. According to EGNB, the monthly cost of natural gas is equivalent to a cost of $0.076 per kWh of electricity, compared to NB Power's rate of $0.0985. Gazifère has a current total cost of $0.447 per m^3 for residential service (for the first 50 m^3), or $11.80 per GJ, which includes the delivery charge transportation charge, and a gas supply charge of $0.14 per m^3, but excludes the monthly fixed charge of $10.05. The equivalent price of electricity in their service area from Hydro Québec is $0.054 per kWh, or $15.00 per GJ. Heritage Gas has a current total cost of $15.351 per GJ for residential service, which includes the base charge and a gas cost of $6.95, but excludes a monthly $21.87 customer charge. According to Heritage Gas, the monthly cost of natural gas is equivalent to a cost of $0.056 per kWh. This compares to Nova Scotia Power's rate of $0.144 per kWh.

21.1.2 Number and type of deferral accounts and true-up mechanisms to capture variances and mitigate risks.

Response:

The requested information is provided in the table below:

	Deferral Accounts
Gazifère	Temperature Stabilization Account
	Lost Gas Volume Variance Account
	Self- Insurance
	Gas Cost Adjustment Variance Account
	Novoclimat, An Energy Efficiency Certification, Rebate Program
	Regulatory Expense
	Demand Side Management (Pgeé)
	PGEE Volume Variances
	Variance Account For Agency For Energy Efficiency (AEE) Expense
	Green Energy Fund Variance Account
Heritage Gas	Revenue Deficiency Deferral Account
	Large Volume Customer Competitive Supply Cost Deferral Account
EGNB	1/

1/ Prior to the provincial legislation introduced in 2011 that rendered EGNB's revenue deficiency deferral account (RDDA) inoperable, EGNB's RDDA captured all variances between actual revenues and expenses. Ms. McShane is not aware of any individual deferral accounts that have been requested or put in place since the provincial legislation was introduced.

21.1.3 Annual growth in number of customers in the past five years.

<u>Response:</u>

The requested customer growth data are shown in the table provided in the response to BCUC FEVI FEW IR 1.20.2.

21.1.4 Annual growth in throughput in the past five years.

Response:

The requested annual growth rates over the most recent 5 years for which Ms. McShane has data are below:

	Period Covered	Annual Growth Rate
Enbridge Gas NB	2008-2012	5.9%
Gazifère	2005-2009	2.3%
Heritage Gas	2006-2010	89.2%

21.1.5 Customer profile by customer accounts, demand and delivery margin.

Response:

The requested customer profile data are shown in the table provided in response to BCUC FEVI FEW IR1 20.2.

21.2 In the cases of EGNB and Heritage Gas, are their special circumstances related to the objective of their development to distribute Maritime natural gas?

Response:

Yes, Heritage Gas and Enbridge Gas New Brunswick are both relatively new gas distributors, which were created to develop and operate natural gas distribution utilities in Nova Scotia and New Brunswick respectively.

22.0 Reference: Exhibit B1-71, Tab B, pp. 17-21

Common Equity Ratios

Ms. McShane describes in her Evidence that some regulators' approach in compensating for differentials in business risk among utilities is through capital structure (e.g., Alberta, Ontario), whereas some, like the BCUC, do not and therefore, the corresponding equity risk premiums need to be taken into account also.

Ms. McShane provided two examples, EGNB and Heritage Gas whose current allowed equity ratios are both 45 percent, a component of their higher business risk relative to their mature peers has been reflected in significantly higher equity risk premiums.

Table 2 shows that EGNB has 275 bps risk premium and Heritage Gas has 200 bps risk premium.

22.1 The current EGNB has an allowed equity ratio of 45 percent. Please provide EGNB's equity ratio in 2010. Is it higher or lower? What was the reason for the change?

Response:

Ms. McShane indicates that EGNB's allowed equity ratio was reduced from 50% to 45% in November 2010. The driving factor was the regulator's conclusion that the utility had moved toward maturity since 2000 and that movement should be reflected in the capital structure.

22.2 Please confirm that when the 2.75 percent risk premium was awarded to EGNB, EGNB was at risk of not being able to recover its deferral account.

Response:

Confirmed. Ms. McShane indicates that this was an important business risk consideration, among others.

22.2.1 Please comment on the magnitude of its deferral account and its gas rates?

Response:

At the time of the cost of capital proceeding in 2010, the deferral account balance was $155 million. Currently the small general service rate class rate is $21.17/GJ, which includes gas costs of $9.50/GJ, but excludes the $16 per month customer charge. This rate is market based and is lower than the equivalent heating oil and electricity rates.

22.2.2 Were the EGNB's gas rates capped by the provincial legislature?

Response:

Yes, commercial and industrial rates were capped at 120% of costs. However, in May 2013, the Court of Appeal of New Brunswick decided that the provincial cabinet had overstepped its authority in the regulations adopted in 2011 in limiting the way the utility regulator can set rates.

22.2.3 Please explain any special circumstances that exist for EGNB related to its agreement to build a natural gas distribution company in NB. Please describe EGNB's capture rates compared to initial expectations.

Response:

In 2000, EGNB was granted a general franchise to distribute natural gas in New Brunswick. The utility's customer attachments (capture rates) have been significantly lower than initially forecast and the utility accrued a materially higher cumulative revenue deficiency than it had anticipated. In 2011, the Gas Distribution Act was amended to exclude the revenue deficiency account from the regulated assets of the utility and to not permit the utility to earn a return on it or to create a new deficiency account except as permitted under the regulations, i.e., the regulations referenced in BCUC IR 2.22.2.

22.3 Please confirm that the 275 bps premium for EGNB resulted in an allowed ROE of 10.9 percent in 2012, which implies that the premium was over 8.15 percent "benchmark ROE," lower than the 9.5 percent benchmark ROE in B.C. If unable to confirm, please provide EGNB's ROE in 2012.

Response:

Confirmed. The 8.15 percent benchmark was actually explicit.

22.4 Please confirm that both the 11.0percent ROE for Heritage Gas and the 9.0 percent for Nova Scotia Power Inc. (NSPI) are negotiated.

Response:

Confirmed.

22.4.1 Are there specific methodology used to determine the 200 bps risk premium for Heritage Gas? If available, please describe the specific methodology.

Response:

No, as both were negotiated ROEs, the indicated risk premium is simply the difference between the two.

22.5 Does NSPI have more market share in space and water heating in Nova Scotia than BC Hydro in the Vancouver Island service area and the Whistler service area? Please provide the comparative data in your response.

Response:

To Ms. McShane's knowledge there are no NSPI specific data available. However because NSPI provides the preponderance of electricity to the Nova Scotia market, Natural Resources Canada data for the province of Nova Scotia can be used as a reasonable approximation.

In 2010, the residential electric market share of space heating secondary energy in Nova Scotia was 19.9%. The residential electric market share of water heating secondary energy use was 21.7%. The largest residential market share in Nova Scotia belonged to heating oil, which had a 62.8% market share in space heating and a 73.2% share in water heating during 2010. No commercial sector data specific to Nova Scotia are available, as Natural Resources Canada combines the commercial sector data for Nova Scotia with the other Atlantic Provinces.

There are no data available specific to BC Hydro's market share in either FEVI or FEW's service area. In British Columbia as a whole during 2010, the electricity share of residential market space heating secondary energy was 32.6% versus natural gas' 53.5% share. Electricity had a 17.8% share of water heating secondary energy use in the residential market in British Columbia during 2010 with natural gas having an 80.7% share.

23.0 Reference: Exhibit B1-71, Tab B, pp. 25-27; Schedule 2

Implication of Cost of Equity

Ms. McShane states that three approaches can be used to quantify the range of the impact of a change in financial risk, or the common equity ratio, on the cost of equity. They were each described in Appendix F in Exhibit B1-9-6.

According to Ms. McShane's anlaysis, the indicated difference in ROE at the recommended 43.5 percent common equity ratio for FEVI versus a 48 percent equity ratio, which is the mid-point of a range of reasonableness she picked, is 50 bps. Thus, based on the estimated differential, in isolation, the indicated equity risk premium for FEVI is approximately 50 bps and for FEW is approximately 55 bps.

Ms. McShane concludes that an increase in financial risk (debt ratio) will be accompanied by an increase in the cost of equity. She says that her analysis shows that, if the Commission were to deem the same 38.5 percent common equity ratio for FEVI and FEW as for FEI, equity risk premiums of approximately 115 basis points and 130 bps above the benchmark utility would be warranted for FEVI and FEW respectively.

23.1 Please show the detailed calculations of the analysis that the difference in the cost of equity between a 38.5 percent common equity ratio and the 43.5 percent and 45 percent common equity ratios recommended for FEVI and FEW respectively is approximately 65 and 80 bps for the ROE equity risk premium.

Response:

Please refer to Attachment 23.1 for the requested calculations comparing the benchmark common equity ratio to the recommended common equity ratios. A summary of the results is presented below:

FEVI	
Change from 38.5% to 43.5%	
	Change in ROE
Approach 1	0.75% (75 basis points)
Approach 2	0.54% (54 basis points)
Tax Rate = 0%	0.62% (62 basis points)
Average	**0.64%**
FEW	
Change from 38.5 to 45%	
Approach 1	0.98% (98 basis points)
Approach 2	0.69% (69 basis points)
Tax Rate = 0%	0.80% (80 basis points)
Average	**0.82%**

23.2 Please show the detailed calculations of the analysis that if the Commission is to establish the same 38.5 percent common equity ratio for FEVI and FEW as for FEI, ROE equity risk premiums are approximately 115 bps and 130 bps above the benchmark utility.

Response:

As Ms. McShane stated on Exhibit B1-71, Tab B, page 25, lines 672 to 673, based on the benchmarks, the range of reasonable common equity ratios for FEVI is approximately 43.5% to 52%. For purposes of determining the incremental risk premium for FEVI above the benchmark, the recommended common equity ratio of 43.5% is compared to the approximate mid-point of the range, 48%. For FEW, as stated at page 27, lines 733 to 736, given its higher business risks relative to FEVI, the corresponding comparison is determined to be at the upper end of the range, i.e. approximately 50%, versus the recommended 45%. The resulting estimated differentials of 50 and 55 basis points for FEVI and FEW, respectively, recognize the higher financial risk of the two utilities arising from setting the deemed equity ratios at the lower end of the range of reasonableness (43.5% and 45% respectively) rather than the 48% and 50%. Please refer to Attachment 23.2 for the calculations. The calculations are summarized below:

FEVI	
Change from 43.5% to 48%	
	Change in ROE
Approach 1	0.60% (60 basis points)
Approach 2	0.42% (42 basis points)
Tax Rate = 0%	0.49% (49 basis points)
Average	**0.50%**
FEW	
Change from 45% to 50%	
Approach 1	0.64% (64 basis points)
Approach 2	0.45% (45 basis points)
Tax Rate = 0%	0.53% (53 basis points)
Average	**0.54%**

Ms. McShane's view is that if the Commission were to deem common equity ratios of 38.5% for FEVI and FEW rather than recommended common equity ratios of 43.5% and 45%, the incremental risk premium, in isolation, i.e., based on capital structure theory alone, would be equal to the sum of 1) the incremental risk premiums shown in the response to BCUC FEVI-FEW IR 1.23.1, reflecting the incremental risk premium accounted for by the higher recommended equity ratios versus FEI, and 2) the incremental risk premiums shown above, reflecting the additional financial risk of FEVI and FEW indicated by setting the deemed equity ratios at the lower end of the range. Therefore, FEVI's incremental risk premium relative to FEI would be equal to the sum of 65 basis points plus 50 basis points or 115 basis points. For FEW, the incremental risk premium relative to FEI at a 38.5% common equity ratio would be 80 basis points plus 55 basis points or, as rounded, approximately 130 basis points.

24.0 Reference: Exhibit B1-71, Tab B, pp. 28-31

Betas

On page 31 of her testimony, Ms. McShane states:

> "the average of the difference between the relevered betas of the FEVI proxy split-rated sample and the A-rated (benchmark utility proxy) sample was 0.12. The average of the differences in the betas of the alternative FEVI proxy BBB+/Baa1-rated sample and the A-rated sample was 0.25. At a market risk premium of 6.4%, those differences translate into a difference in the cost of equity ranging from 75 to 165 basis points (mid-point 120 basis points)."

> "The average of the difference between the relevered betas of the FEVI proxy split-rated sample and the A-rated (benchmark utility proxy) sample was 0.12. The average of the differences in the betas of the alternative FEVI proxy BBB+/Baa1-rated sample and the A-rated sample was 0.25."

> "The average of the differences in the betas of the FEW proxy BBB/Baa-rated category sample and of the A-rated sample was 0.23."

24.1 Is Ms. McShane's methodology to re-state the betas as "relevered betas" an accepted methodology? Please provide examples or cite academic journals and industry practices that have carried out her methodology.

Response:

The approach used by Ms. McShane of unlevering and relevering betas to isolate differences due solely to differences in business risk as set forth in Exhibit B1-71, Tab B, page 30, footnote 24 is not Ms. McShane's methodology. The formula set forth in the footnote is referred to as the Hamada formula or equation and is premised on the well-known work of Modigliani and Miller (MM) in their series of articles that explained the modern financial theory with respect to cost of capital and capital structure. Those articles were:

- M. Miller and F. Modigliani, "Dividend Policy, Growth and the Valuation of Shares, " *Journal of Business*, October 1961
- M. Miller and F. Modigliani, "The Cost of Capital, Corporation Finance, and the Theory of Investment," *American Economic Review*, June 1958.
- M. Miller, "Debt and Taxes," Journal of Finance, May 1976
- F. Modigliani, "Debt, Dividend Policy, Taxes, Inflation and Market Valuation," *Journal of Finance*, May 1982.

In Robert S. Hamada's article, "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stocks", *Journal of Finance*, May 1972, Hamada tested the MM theory and the capital asset pricing model indicating that the Hamada equation did reflect an accurate quantification of the differences in systematic risk between the leveraged and leverage-free firm. By using the Hamada formula it is possible to estimate the cost of capital for individual firms at varying degrees of leverage without resorting to an extensive risk-class study to obtain the relevant benchmarks for debt and preferred stock.

The use of the Hamada equation to distinguish between financial and business risk is discussed in basic financial management texts, e.g., Eugene F. Brigham and Louis C. Gapenski, *Financial Management, Theory and Practice*, 4th edition, Dryden Press, 1997.

The Hamada equation is discussed specifically in relation to regulated utilities in the following text: Dr. Roger A. Morin, PhD., *New Regulatory Finance*, Public Utilities Reports, Inc. (2006), Chapter 7.

It is widely used in practice to take account of differences in capital structure. In the article *Incorporating Default Risk into Hamada's Equation for Application to Capital Structure*, Wilmott Magazine, 2007, Ruben D. Cohen stated:

> *Implemented widely in the area of corporate finance, Hamada's Equation enables one to separate the financial risk of a levered firm from its business risk. The relationship, which results from combining the Modigliani-Miller capital structuring theorems with the Capital Asset Pricing Model, is used extensively in practice, as well as in academia, to help determine the levered beta and, through it, the optimal capital structure of corporate firms.*

24.1.1 In Footnote 24, Ms. McShane describes her methodology. Please comment on the effects of changes to corporate tax rate over the period 2008-2012 and changes to corporate tax rate among jurisdictions to the relevered betas.

Response:

With reference to the methodology being attributed to Ms. McShane in the question, as described in the response to BCUC FEVI-FEW IR 1.24.1, Ms. McShane employed a widely accepted and applied methodology.

Although changing tax rates can impact the unlevered and levered beta calculations, the estimates were done using the U.S. marginal federal corporate tax rate of 35%, as these are U.S. firms. The federal rate of 35% was adopted in 1986, and the beta estimates rely on data beginning in 2004.

24.2 If FEW does not have any debt rating or credit opinions, can the beta differentials approach be useful and reasonable to determine FEW's equity ratio and equity risk premium?

Response:

Yes, it is possible because an analyst can assess FEW's relative risk, from which a hypothetical debt rating can be specified.

24.3 With respect to Ms. McShane's testimony regarding the differences at a market risk premium of 6.4 percent translate into a difference in the cost of equity ranging from 75 to 165 bps, please confirm this range is only estimated for FEVI. If not confirmed, please clarify.

Response:

Yes, this range, which appears at Exhibit B1-71, Tab B, page 31, lines 832 to 835, refers to FEVI. The subsequent two sentences, at lines 835 to 838, provide the estimate for FEW as follows:

> *The average of the differences in the betas of the FEW proxy BBB/Baa-rated category sample and of the A-rated sample was 0.23. At a 6.4% market risk premium, the associated difference in the cost of equity between the two samples is close to 150 basis points.*

24.4 Are the figures 0.12 and 0.25 quoted in the preamble an average of 'unadjusted' and 'adjusted' betas?

Response:

Yes. Please refer to Attachment 24.4 for the working spreadsheet.

24.5 The range between 75 to 165 bps is 90 bps. Does Ms. McShane have any concerns regarding preciseness and accuracy of the betas differential results?

Response:

No, there is an unavoidable degree of imprecision in cost of equity estimation.

25.0 Reference: Exhibit B1-71, Tab B, pp. 33-35

Size Premiums

The Ibbotson analysis, which looks at returns for different size equities, where size is defined as market capitalization, shows two facets of the impact of size on returns. First, the analysis shows that there is an inverse relationship between market capitalization and betas, i.e., smaller firms tend to have higher betas than larger firms. Second, the analysis shows that small firms tend to earn higher returns than predicted by the Capital Asset Pricing Model and their betas.

25.1 With respect to the analysis showing that small firms tend to have higher betas than larger firms, please indicate the sector type (e.g., all industries or utilities), data used (e.g. timeframe and location), and the nature of business (e.g., competitive or monopolistic).

Response:

All industries are included. The equities used are U.S. equities and the data cover the period 1926 to 2012.

25.2 Would the size premium be treated any different in a competitive versus monopolistic business nature? For example, Ms. McShane states, "As FEVI and FEW are regulated utilities, they are afforded protection not available to the unregulated firms that would comprise the majority of the firms in the Ibbotson analysis. Consequently, it is reasonable to conclude, while still arelevant factor, the size premia applicable to utilities are smaller than those applicable to companies that operate in fully competitive markets." (Tab B, p. 35)

Response:

Ms. McShane is not certain what is meant by "treated any different". Although the magnitude of the risk premium investors would require to account for small size may be different for competitive and regulated firms, there is no reason to believe that it would be "treated any different'.

25.3 Is it fair to assume that Ms. McShane only relies on the Ibbotson analysis to support the general proposition that a size premium exists but she does not rely on the analysis to recommend the actual premiums for FEVI and FEW?

Response:

It is correct to conclude that Ms. McShane has not expressly used the Ibbotson results presented in Table 7 of her testimony to quantify the risk premiums for FEVI and FEW.

26.0 Reference: Exhibit B1-71, Tab D, Moody's Credit Opinion of FEVI dated June 26, 2013; Tab E, DBRS Credit Opinion dated June 11, 2013

Financial Metrics – FEVI

Moody's Credit Opinion of FEVI dated June 26, 2013 states:

> "Given the GCOC's downward revision to the benchmark ROE and potential for a reduced equity layer, we expect that <u>FEVI's CFO pre-WC to debt could potentially fall below 13% over the intermediate-term.</u>" [Emphasis added]

The DBRS Credit Opinion dated June 11, 2013 states:

> "Given that FEVI's cost of capital is based on FEI's cost of capital, FEVI's ROE has decreased to 9.25%, effective January 1, 2013, from the previous ROE of 10%. The current equity component in capital structure of 40% and ROE risk premium of 0.5% will be reviewed in phase 2 of the GCOC proceeding and may change. <u>DBRS does not expect these decisions to have a material impact on the Company's earnings and cash flow</u>." [Emphasis added]

26.1 Please clarify what are the common equity ratio and allowed ROE assumptions for Moody's to conclude that FEVI's CFO pre-WC to debt could potentially fall below 13 percent over the intermediate-term.

<u>Response:</u>

FEVI is not aware of the assumptions used by Moody's in its analysis of certain events and the potential future impact those events may have on FEVI's future credit metrics. FortisBC can only speculate that the revised equity thickness and revision to the benchmark as made in their statement refers to the revision to the benchmark ROE decrease of 75 basis points and the reduced equity layer is that of the Benchmark - 38.5%.

26.2 To the best of FEVI's knowledge, why would DBRS expect that the GCOC Stage 2 Decision would not have a material impact on the FEVI's earnings and cash flow whereas Moody's appear to be concerned about FEVI's financial metrics?

<u>Response:</u>

Moody's and DBRS are separate, independent, third parties, entitled to differing views. For example, this is demonstrated by the fact DBRS rates FEVI BBB(high) and Moody's has a higher rating of A3, while Moody's rates FEI A3, yet DBRS has a higher rating of A. FEVI doesn't know why they differ with respect to the impact of the Stage 2 decision on earnings and cash flow.

26.3 Please explain why FEVI's debt ratings and credit opinions should affect the equity ratio of FEW when the two utilities have different business risks and financial metrics.

Response:

The Companies do not see where the rating agencies have discussed FEW's equity ratio in the above referenced passages or reports, and thus are unsure of what is intended by the question.

26.3.1 Are there any instances in cost of capital proceedings where the conclusions of a utility credit rating are transferrable to a non-rated sister company? If so, please specify.

Response:

Cost of Capital proceedings do hear evidence from experts comparing a Utilities business risk to other rated Utilities with similar business risks, however, FEVI is not aware of proceedings where the credit rating of one entity is transferred, in some form, to a non-rated sister company.

26.3.2 Should the "stand alone" principle apply to FEW compared to FEVI?

Response:

Yes, the "stand alone" principle should apply to FEW.

27.0 Reference: Exhibit B1-71, Tab E

DBRS Credit Opinion dated June 11, 2013 – FEVI

The DBRS Credit Opinion dated June 11, 2013 states:

> "Given that FEVI's cost of capital is based on FEI's cost of capital, FEVI's ROE has decreased to 9.25%, effective January 1, 2013, from the previous ROE of 10%. The current equity component in capital structure of 40% and ROE risk premium of 0.5% will be reviewed in phase 2 of the GCOC proceeding and may change. DBRS does not expect these decisions to have a material impact on the Company's earnings and cash flow." [Emphasis added]

27.1 Is DBRS suggesting that, all other things equal, there will be no material impact on FEVI's credit rating if the Commission establishes a common equity ratio of 40 percent and a ROE risk premium of 50 bps? If not, why not?

Response:

DBRS has stated that they do not expect the decision from Stage 2 of the GCOC proceeding (which would be limited to a change to the current 40% equity ratio or the 0.50% risk premium), to have a material impact on the Company's earnings and cash flow. Therefore, if the Commission maintains the 40% equity ratio and the 0.50% equity risk premium, there should be no material impact on earnings or cash flow from the perspective of DBRS. DBRS has not commented on the impact on credit rating in the above quoted passage, however, if the only consideration to the rating was the change in earnings and cash flow, then one could presume there should be no material impact to the DBRS rating.

Attachment 5.1

Diane Roy
Director, Regulatory Affairs - Gas
FortisBC Energy Inc.

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

March 28, 2013

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 No. G-152-07 Compliance Filing; and**
- **FEI Vertical Subdivision Report – Commission Order No. G-6-08 Compliance Filing**

On October 16, 2012 in response to the FEI-FEVI Year End MX Report and FEI Vertical Subdivision Report (the "MX Report") filed for 2011, the Commission issued letter L-60-12, which found the report to be generally compliant. In the letter, the Commission also identified a number of enhancements that were to be included in the 2012 MX Report to improve the clarity and completeness of the MX Report.

In response to Commission Staff's requests, as identified in letter L-60-12, the Companies respectfully submit the attached 2012 MX Report. In addition to reflecting the format and methodologies utilized in the previously approved 2011 MX Report, the 2012 MX Report provides the requested enhancements and continues to comply with Orders No. G-152-07 and No. G-6-08.

We trust that the Commission will find the report in order and request confirmation from the Commission that the 2012 MX Report is in compliance with Orders No. G-152-07 and No. G-6-08. If there are any questions, please contact Mike Metza at 604-592-7852.

Yours very truly,

FORTISBC ENERGY INC.
FORTISBC ENERGY (VANCOUVER ISLAND) INC.

Original signed by: Ilva Bevacqua

For: Diane Roy

Attachment

FortisBC Energy Inc.
FortisBC Energy (Vancouver Island) Inc.

Main Extension Report for 2012 Year End

Compliance Filing in Accordance with Commission Orders No. G-152-07 and G-6-08

March 28, 2013

Table of Contents

List of Appendices

Index of Tables and Figures

1 EXECUTIVE SUMMARY

The Main Extension ("MX") report from FortisBC Energy Inc. ("FEI") and FortisBC Energy (Vancouver Island) Inc. ("FEVI") (collectively called the "Companies") and the FEI Vertical Subdivision ("VSD") Report for 2012 Year End (collectively referred to as the "Report") are respectively filed in accordance with British Columbia Utilities Commission (the "Commission") Orders No. G-152-07 and No. G-6-08.

The primary findings in the Report are summarized below:

1. **The Companies are in compliance with the Commission reporting directives and continue to refine reporting practices based on Commission feedback.**

The 2012 MX Report continues to comply with and contains the requisite information in accordance with Commission Orders No. G-152-07 and No.G-6-08. The regulatory history section of this Report contains a detailed outline of the MX Report history. The 2012 MX Report format has been updated based on feedback received from Commission Staff while continuing to reflect the format and methodologies utilized in the previously approved 2011 MX Report.

2. **The variance in forecast versus actual main extension costs is reasonable.**

The Companies' methods of cost forecasting continue to provide a reasonable representation of actual project costs. Current forecasting methods capture an extensive scope of project-related expenses such as planning, materials and labour, and service line costs, which will generally have a higher level of variance when compared to mains cost due to the unique characteristics of individual lots. For the 2012 MX Report, the cost variances contained in this Report are reasonable as further demonstrated below.

3. **Attachments continue to follow economic conditions and are generally on track.**

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 consumption quantity and expected time of attachments on new main extension projects. However, similar to other utilities such as water and electricity, the Companies' forecasts are primarily affected by economic conditions and a multitude of other variables which can result in a misalignment of 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. For the 2012 MX Report, the attachment variances relate closely to economic and housing market conditions and are generally on track or improving on an annual basis.

4. Actual consumption levels are consistent with new customers.

The Companies consumption forecasts used in the Main Extension test are based on the best available 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 are accurate in that they are reflective of the existing customer base. However, the consumption patterns of new customers presented throughout the 2012 MX Report and previous reports have highlighted significant differences between new and existing customers. For the 2012 MX Report, the actual consumption levels are representative of new customers and the impacts current technological improvements and energy efficiency gains present in today's housing market; while the forecasted levels represent the consumption levels of all existing customers on the Companies distribution system who connected to the system in an entirely different environment.

5. The Company has provided a plan to address low aggregate Profitability Index ("PI") thresholds on a go-forward basis.

As a result, Commission Staff have required the Companies to come up with a "plan" to determine if the PI thresholds need to be adjusted on a go-forward basis in order to achieve the aggregate PI threshold of 1.1. In response to the Commission requirement detailed in letter L-60-12 issued on October 16, 2012, the Companies have attached as Appendix C, a detailed System Extension policy review with recommendations on how to improve the Companies' PI on a go-forward basis.In summary, the Companies will continue to apply the format and methodologies used in the 2012 MX Report for future reports as they are a direct result of suggestions by Commission Staff. The Companies also propose to develop a framework for System Extension policy enhancements through a collaborative effort with Commission Staff and Stakeholders based on the findings of the System Extension Policy review in Appendix C.

2 REGULATORY HISTORY

On July 31, 2007, FEI and FEVI[1] applied to the Commission for changes to the System Extension and Customer Connection Policies ("System Extension and Customer Connection Policies Review"). In December, 2007, the Commission issued Order No. G-152-07 and Reasons for Decision ("Order No. G-152-07") approving changes requested in the Companies System Extension and Customer Connection Policies Review. Commission Order No. G-152-07 established the parameters for the MX Test and the Companies were directed to file with the Commission an annual MX Report (page 37 of G-152-07):

> *"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."*

Subsequently, FEI was directed to make revisions to the MX Test methodology and was further directed to provide information relating to Vertical Subdivisions under Commission Order No. G-6-08[2] issued on January 10, 2008:

> *"Terasen is directed include, in the Main Extension Report that Terasen was directed to file in the Commission's Main Extension Decision, the results of TGI's main extension tests to Vertical Subdivisions."*

The Companies applied the MX Test (also referred to as the "economic test" or "system extension test") as approved by the Commission to 2007, 2008 and 2009 main extensions, and filed the respective Main Extension reports in compliance with the requirements of Orders No. G-152-07 and No. G-6-08 on April 7, 2008, April 3, 2009 and April 10, 2010 respectively.

As a result of discussions with Commission Staff subsequent to the filing of the 2009 Report and a meeting with Commission Staff held on July 13, 2010, the Companies submitted a revised 2009 Report on August 18, 2010 with further information requested by Commission Staff. FEVI also submitted a detailed report for the Shawnigan Lake Main Extension, providing additional

[1] Then Terasen Gas Inc. (TGI) and Terasen Gas (Vancouver Island) Inc. (TGVI) respectively.
[2] Order No. G-6-08 was issued in response to an application by FEI (then TGI) to amend the general terms and conditions of its Tariff to allow an alternative method of providing gas service to Vertical Subdivision developments.

information and explanations for the performance of the Shawnigan Lake Main Extension based on then available information.

The Companies and Commission Staff continued their dialogue with respect to the MX Report via written correspondence, phone calls and a meeting on February 15, 2011, to review the compliance reporting requirements. As agreed with Commission staff, the Companies filed a draft report on March 31, 2011, prior to filing the final 2010 MX Report. The Companies then met with Commission Staff on April 12, 2011, and presented the findings contained within the draft report. Commission Staff provided comments on the draft report on April 20, 2011.

On June 1, 2011, the Companies filed the final 2010 MX Report, believing that the final 2010 MX Report was in full compliance with Orders No. G-152-07 and No. G-6-08.

On August 30, 2011, the Commission issued Letter No. L-67-11, which identified several issues for the Companies to address in the annual MX report. The Commission requested the Companies to:

- *Re-file within 45 days of the date of this Letter a fully compliant and informative 2010 MX Report in accordance with Commission Order G-152-07 and its Decision, Order G-6-08, and as clarified in this Letter L-67-11.*
- *File within 45 days of the date of this Letter meaningful and informative main extension performance updates on Sooke MX and Shawnigan Lake MX.*

An Addendum report to specifically address each issue identified in L-67-11 was filed October 14, 2011, referred to as the 2010 MX Report Addendum.

On March 22, 2012, the Commission issued Letter No. L-19-12, stating that the 2010 FEI and FEVI Year End Main Extension Report and the Addendum to the 2010 Main Extension Report still did not comply with the reporting requirements in Orders No. G-152-07 and No. G-6-08.

In order to have a clear understanding of the MX Report compliance requirements from the Commission's perspective and to provide an MX Report satisfactory to the Commission, including the MX Report format and methodologies, the Companies and Commission Staff met on March 28, 2012 and April 26, 2012. As a result of these discussions and further phone and email correspondence with Commission Staff, an agreed upon set of reporting tables and methodologies were developed to act as a framework for the 2011 MX Reports and future MX Reports.

On July 31, 2012, the Companies filed the 2011 MX Report, in full compliance with Orders No. G-152-07 and No. G-6-08. The report reflected the framework and methodologies developed as part of the previously mentioned meetings. A complete list of the updated reporting requirements is provided in the 2011 MX Report[3].

On October 16, 2012, in response to the 2011 MX Report, the Commission issued letter No. L-60-12 which found the report to be generally compliant. In the letter, the Commission also identified a number of enhancements that were to be included in the 2012 MX Report to improve the clarity and completeness of the Report. A brief summary of the reporting enhancements are as follows:

Letter L-60-12 Item	2012 MX Report Implementation
Consumption and Use Per Customer should be changed from a cumulative result to an annual result.	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.
Provide a breakdown of attachments, consumption and use per customer segmented by rate class.	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 will now reflect segmentation by rate class.
Include an explanation as to whether or not consumption Ramp-Up analysis was conducted.	Past practice has been to apply Ramp-Up on a per project basis at the planner's discretion. For those projects throughout this report that show a Ramp-Up factor of zero, the 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.
Include 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.
Include a plan to address low aggregate PI thresholds on a go-forward basis.	Please see Section 3 for a discussion of this requirement and refer to Appendix C of this report for a full and detailed response.

The 2012 MX Report has been updated to address Commission Staff's requests as identified in Letter No. L-60-12, which are outlined above. Also, based on the direction received from Commission Staff, the 2012 MX Report continues to reflect the format and methodologies

[3] FEI & FEVI Main Extension Report for 2011 Year End, submitted on July 31, 2012 – Section 1, p10.

utilized in the previously approved 2011 MX Report. All tables, charts, and calculations contained in the 2012 MX Report are reproductions of previously agreed upon designs which have been revised with updated figures. Also, as seen in Table 1 below, the 2012 MX Report continues to comply with and contains the requisite information in accordance with Commission Orders No. G-152-07 and No. G-6-8.

Table 1: 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.	pp.20-27
G-152-07	Update FEVI MX test to reflect FEVI use per appliance.	pp.24
G-152-07	Reflect in the Companies' MX tests their experience of the consumption ramp-up in the early months of service.	pp.32-116
G-152-07	Comparison of forecast and actual costs, consumption and PI for the first five years of main extensions in the sample.	pp.32-116
G-152-07	A concise explanation of the random sampling method used.	pp.19-20
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.	pp.32-116
G-6-08	The results of FEI's main extension tests to Vertical Subdivisions.	pp.32-116

The 2012 MX Report is organized in the following manner:

Exploration of PI and EES Whitepaper Introduction: Section 3 below provides a summary of the issues surrounding the historically low PI results as well as the framework for the analysis undertaken on the Companies' System Extension Policies attached as Appendix C and titled "FortisBC Energy Utilities Review of System Extension Policies". The information found in Appendix C and outlined in Section 3 is in response to the Commission requirement in Letter No. L-60-12 to include a plan to address the low aggregate PI thresholds as identified in previous Main Extension Reports, on a go-forward basis.

MX Test and Parameter Details: At the request of Staff, the 2012 MX Report provides detailed information on the Companies' Main Extension Test calculations with accompanying data tables comparing annual MX Test parameter updates for each reporting cohort year retroactive to 2008.

Review of Forecasting Methodologies: The 2012 MX Report also repeats an in-depth discussion on the methodologies and challenges relating to the forecasting of inputs used in every Main Extension Test.

Presentation of Results and Conclusion: An annual break down of Main Extension Test results tables is presented in Sections 6 to 10. The tables have been designed in conjunction with Commission Staff and are organized by reporting cohort year.

3 EES CONSULTING LTD. AND THE SYSTEM EXTENSION POLICY WHITEPAPER

3.1 Purpose of Engagement

In the case of the 2012 MX Report and the Commission requirement to formulate a plan to address the low PI thresholds on a go-forward basis, the Companies have engaged EES Consulting to provide research, analysis and recommendations on system extension policy options to assess the appropriateness of PIs on a go-forward basis. Additional prerequisites are also to ensure any recommendations will not adversely affect existing customers, while at the same time continue to promote the use of natural gas as a clean and economical energy source by minimizing any barriers to connection for new customers connecting to the Companies' distribution system for the first time.

EES Consulting Ltd. ("EES Consulting") is a multidisciplinary management consulting firm with particular expertise in Rate Design methodology and Cost of Service Allocation modelling, previously retained by the Commission, FortisBC Inc. and FEI for the validation of rate design methodologies and models. EES Consulting is familiar with the FortisBC Energy Utilities' ("the FEU[4]") business and has been retained by the Companies on an ad-hoc basis for several years.

3.2 Understanding the Profitability Index

Previous Main Extension Reports have shown the aggregate PI for both FEI and FEVI to be below the 1.1 threshold outlined in Order No. G-152-07. As a result and as part of the 2012 MX Report, Commission Staff have required the Companies to come up with a "plan" to determine if the PI thresholds need to be adjusted on a go-forward basis in order to achieve the aggregate PI threshold of 1.1.

Although the Companies recognize the importance of assessing each main extension project before it begins to better understand the potential effects on existing and new customers, there remains considerable question around the use of the PI as the measure of performance of projects and the Companies themselves, especially when taken within the context of the Companies' annual Main Extension Report. The PI contained in the MX Reports should be viewed as a snapshot in time only. In fact, due to the five-year reporting structure, many results reviewed by the Commission should only be considered to be preliminary in nature as they are highly vulnerable to economic conditions which will significantly raise or lower the PI of a new main extension simply based on present housing market demand levels and the re-forecasting methodologies required by the Commission. As will be seen throughout the results of this MX Report, the majority of main extensions continue to add customers year after year. However, these actual attachments are, in most cases, misaligned with original forecasts due to the difficulties in determining exactly when a home in a given subdivision will be planned, constructed, sold and the meter activated. These ongoing and potential future customer

[4] The FEU consist of FEI, FEVI and FortisBC Whistler Inc.

connections support the notion that the PI at any given time on an existing main is generally representative of that point in time only. When considered in conjunction with re-forecasting methodologies where unrealized attachments are assumed to have disappeared forever, the PI becomes even less representative of the long-term potential economic benefits to customers.

The current MX Test itself is also structured in such a way that it lends itself to being viewed as a short-term measure based on the maximum twenty-year discounted cash flow of all main extension projects. Because the vast majority of the Companies' assets last well beyond twenty years, the MX Test does not accurately portray the final, economic impact of a main extension project on rate payers as it assumes customers simply disappear from the FEU systems at the end of twenty years. In reality, many customers' homes at this time are undergoing renovations or their neighbourhoods are undergoing renewal. A prime example would be the demographic shift in Vancouver's residential neighbourhoods where coach homes are being added in addition to existing single family dwellings. This represents unanticipated additional consumption on a pre-existing main and would translate into an improved PI, well after the twenty year PI calculated in the Companies' current Main Extension Test. Furthermore, many main extensions spawn additional main extensions which are not translated back, or have an effect on, the original system extension (due to the current five year window of forecasting attachments). This additive effect can serve to make original main extensions even more positive than would be shown in current reporting. Therefore the only way to truly asses the viability of a main extension is at the end of life of the economic period.

3.3 EES System Extension Policy Review

The Companies intend to use the recommendations from EES Consulting to form the framework for a proposed System Extension policy review to support higher PI's for new main extension projects on a go-forward basis in relation to the issues discussed above. The EES report found in Appendix C, titled "FortisBC Energy Utilities Review of System Extension Policies" provides the following information:

- Analysis of existing FEU main extension policies
- Identification of issues within current FEU policies
- Review of alternative methods and final recommendations.

3.4 System Extension Policy Review Process Objectives

The Companies propose the following preliminary schedule as an outline of how the Companies propose to engage with Commission Staff and our Stakeholders regarding the review of the MX Test policies recommendations outlined above:

- 2012 MX Report Submission March 31, 2013;
- Initial meeting between the Companies and Commission Staff early April 2013. The purpose of this meeting is to review the results of the 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.

The above list is intended to provide a preliminary framework only and can be refined and updated based on discussion with Commission Staff and potential Stakeholders once initial reviews of this material are completed.

4 MAIN EXTENSION TEST METHODOLOGY

The following section summarizes the formula for the MX Test, the inputs into the 2012 MX Test and the methodology used to present the results of the 2012 MX Report.

For background, the Companies have provided in Appendix A and Appendix B the applicable Definitions and Section 12: Main Extension of the FEI General Terms & Conditions ("GT&Cs"). The relevant terms found in these appendices apply throughout the 2012 MX Report. In addition, the Companies have also provided a set of comprehensive data for the years 2008 to 2012 for each of the MX Test parameters tables discussed in this section. Although the focus of the 2012 MX report is based on a comparison of the 2012 versus 2011 gas year, the Companies have included past year's data for reference purposes pursuant to the agreed upon methodology with Commission Staff.

4.1 Main Extension Test Formula

All applications to extend the gas distribution system to one or more new customers are subject to an MX Test approved by the Commission. The MX Test formula develops a PI which is the ratio of the discounted present value of all forecast net cash inflows over twenty years divided by the discounted present value of the capital costs of attaching customers in the first five years of the main extension.

While there are many components factored into the calculation of this ratio, the following formula provides a summary of the major components:

$$\textbf{P.I.} = \frac{\begin{array}{c}\textbf{Net Present Value of Net Cash Inflows}\\ \text{(Delivery Margin + Connection Fees – O\&M - System Improvement Charge – Property Tax – Income Tax)}\end{array}}{\begin{array}{c}\text{(Mains, Services, Meter Costs)}\\ \textbf{Net Present Value of Capital Costs}\end{array}}$$

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.

4.2 Re-Forecasted PI Calculation Methodology

The re-forecasting methodology used when calculating the updated PI of a main extension has a significant impact on the results contained in this Report. After the submission of the 2010 MX Report, the Commission issued Letter No. L-67-11 which found the Companies method of re-forecasting un-realized attachments to future years insufficient when calculating the re-forecasted PI of a main extension.

Following discussions with Commission Staff, it has been agreed that the Companies will not perform a re-forecasting of unrealized attachments when re-forecasting the PI of a main extension. For example, if a particular project has 50 attachments forecasted for both year 1 and year 2, and the actual year 1 and year 2 attachments figures are 0 and 50 respectively, then the re-forecasted PI calculation would only be based on one half (50 out of 100) of the planned attachments, with the assumption that the other 50 attachments would simply never occur. *Although this may provide a clear and consistent methodology, it will result in a re-forecasted PI that is less representative of the final PI of the project.* In this case, un-realized attachments may simply be deferred for economic reasons or project related complications and could arise in future years lending support to viewing the actual PI calculation as a "snap shot" in time only.

Furthermore, the MX Test applicable to all mains extensions contains both forecasted consumption and attachment figures for a full twenty years after the anticipated install date of the main; therefore a comparable measure of a project's forecasted PI versus actual PI can only be realized after a full twenty years have passed. The five-year time horizon is only relevant for reporting purposes. *The annual MX reports provided to the Commission thus represent a "snap shot" in time view of a main extension or group of main extensions out of the 20 year discounted cash flow ("DCF") time frame*. As discussed earlier, the time horizon for measuring the economic benefits of a project lie beyond 20-year DCF and are better equated to the life of the assets themselves. The BC housing market and the Companies' attachment and consumption results are closely related and cyclical in nature. Inevitably, there will always be uncertainty and variability from year to year inherent in forecasting attachments, despite the Companies' best efforts to apply their industry knowledge, experience and conservative approach to forecasting. The risk of focusing on performance of an individual year is that attachments that did not materialize in a given year may do so at some point in the future of the 20-year DCF time frame. Furthermore, over the 20-year timeframe, there may be attachments that materialize that were not originally forecast by the Companies. In summary, the performance of main extensions in aggregate cannot be fairly evaluated until, at the earliest, the end of the 20-year DCF timeframe.

Both FEI and FEVI currently use the same DCF test to evaluate main extensions; however, the inputs for the tests vary between each utility. A discussion of the net cash inflow, capital cost and discount rate inputs into the MX Test formula for each utility is provided in Section 2.4.

4.3 Main Extension Data

This section outlines the methodology used to establish the relevant main extension sample data sets along with the cost and consumption data provided in the 2012 MX Report.

The 2012 MX Report contains main extension projects that have been organized using the following methodology:

2012 Mains - Contain main extensions for the 2012 gas year (Nov-Oct) including forecasted attachments and consumption data and a comparison of the forecasted and actual mains costs only. The first year of actual attachments and consumption data for this set of mains will be presented in the 2013 MX Report. This group of mains will be updated in each annual MX Report over the next five years, from 2013 to 2017.

2011 Mains - Contain main extensions for the 2011 gas year (Nov-Oct) and includes a comparison of forecasted and actual attachments, consumption and mains costs from November 1, 2010 to October 31, 2011. The results in this report reflect Year 1 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 mains costs from November 1, 2009 to October 31, 2011. The results in this report reflect Year 2 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 mains costs from November 1, 2008 to October 31, 2011. The results in this report reflect Year 3 of actualized data for this group of mains. 2014 will be the final year of reporting for this set of mains.

2008 Mains - Contain main extensions for the 2008 gas year (Nov-Oct) and includes a comparison of forecasted and actual attachments, consumption and mains costs from November 1, 2007 to October 31, 2011. The results in this report reflect Year 4 of actualized data for this group of mains. 2013 will be the final year of reporting for this set of mains.

The 2008-2012 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 2012 MX Report as per Order No. G-152-07. As a result, the 2012 FEI and FEVI populations consist of 285 and 54 completed mains respectively, with a random sample size of 85 and 38 respectively. The data sets for the 2008-2011 gas years have been previously reported and are also based on the random sample method; and as such, all data tables contained in this report are based on the same random sample method. The random samples were determined by calculating a statistical sample size which meets the criteria discussed in Section 2 and then extracting that sample from the populations for each annual data set that met the conditions discussed above.

As stated in previous MX reports, historical main extensions will be reported until the end of the five year period, for example, through to October 31, 2013 for 2008 projects and will include costs, attachment, consumption and PI variance both in aggregate and the top 5 mains for both FEI and FEVI.

4.4 Main Extension Test Parameters

This section provides tables containing details on the parameters used in the Main Extension Test. The focus of reporting is a comparison of 2012 versus 2011 parameters; however, historical parameters have been included at the request of Commission Staff.

4.4.1 NET CASH INFLOWS

As discussed above, net 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 used in the economic test is determined as follows:

a) estimating the number of customers to be served by the main extension[5];
b) establishing consumption estimates for each customer (discussed in the next section);
c) projecting when the customer will be connected to the main extension; and
d) applying the appropriate delivery margin for each customer's consumption.

In the case of FEVI, an effective delivery margin is calculated by subtracting the unit cost of gas from the sales rate. The FEVI sales rate has remained relatively constant throughout the periods covered by the 2010-2011 and 2012-2013 Revenue Requirements Applications (RRAs).[6, 7, 8, 9] The basic and delivery charges, the in lieu rate and new service fee data are as follows:

---

5 Only those customers expected to connect to the main extension within 5 years of the completion are considered.

6 Up to December of 2011, the unit cost of gas includes royalty credits. Including the royalty credits in the cost of gas results in a derived delivery rate that more closely resembles the gross margin of FEVI.

7 FEI Basic and Delivery Charges – "Fortis BC Energy Inc. General Terms and Conditions, Rate Schedule 1, first revision of page R-1.1; Rate Schedule 2, first revision of page R-2.1; Rate Schedule 3, first revision of page R-3.1.)"

8 FEVI Basic and Delivery Charges – "Terasen Gas (Vancouver Island) Inc., Standard Terms and Conditions and Rates for Gas Service, first revision of pages C-2 to C-7 and page C-11".

9 FEI New Service Fees – "FortisBC Energy Inc. General Terms and Conditions", page S-1. As per Commission order no: G-28-11. FEVI New Service Fees – "Gas (Vancouver Island) Inc., Standard Terms and Conditions and Rates for Gas Service", page C-1 as per Commission order G-30-11.

Table 2: Basic & Delivery Charges, In Lieu Rate & New Service Fee

	2008				2009				2010				2011				2012			
Rate Class	Basic Charge ($/yr)	Delivery Charge ($/GJ)	In Lieu Rate (%)	New Service Fee ($)	Basic Charge ($/yr)	Delivery Charge ($/GJ)	In Lieu Rate (%)	New Service Fee ($)	Basic Charge ($/yr)	Delivery Charge ($/GJ)	In Lieu Rate (%)	New Service Fee ($)	Basic Charge ($/yr)	Delivery Charge ($/GJ)	In Lieu Rate (%)	New Service Fee ($)	Basic Charge ($/yr)	Delivery Charge ($/GJ)	In Lieu Rate (%)	New Service Fee ($)
FEI																				
Rate 1	$133.56	$2.78	3.22%	$85.00	$143.88	$3.00	2.97%	$85.00	$142.08	$3.18	2.55%	$25.00	$142.08	$3.28	2.51%	$25.00	$142.08	$3.56	2.23%	$25.00
Rate 2	$280.20	$2.33	3.95%	$85.00	$301.80	$2.51	3.70%	$85.00	$298.08	$2.64	3.11%	$25.00	$298.08	$2.71	3.07%	$25.00	$298.08	$2.93	2.63%	$25.00
Rate 3/23	$1,469.76	$2.01	3.60%	$85.00	$1,610.40	$2.16	3.36%	$85.00	$1,590.24	$2.26	2.87%	$25.00	$1,590.24	$2.32	2.85%	$25.00	$1,590.24	$2.48	2.40%	$25.00
FEVI																				
RGS	$126.00	$5.90	2.11%	$85.00	$126.00	$4.49	2.08%	$85.00	$126.00	$7.69	2.84%	$25.00	$126.00	$8.29	2.81%	$25.00	$126.00	$8.00	1.60%	$25.00
SCS-1	$113.40	$8.44	1.86%	$85.00	$113.40	$7.10	1.87%	$85.00	$113.40	$10.30	2.40%	$25.00	$113.40	$10.90	2.40%	$25.00	$113.40	$10.61	1.57%	$25.00
SCS-2	$402.36	$7.71	1.93%	$85.00	$402.36	$6.62	1.93%	$85.00	$402.36	$9.82	2.55%	$25.00	$402.36	$10.42	2.55%	$25.00	$402.36	$10.13	1.83%	$25.00
LCS-1	$732.00	$4.79	2.49%	$85.00	$732.00	$3.51	2.54%	$85.00	$732.00	$6.71	4.15%	$25.00	$732.00	$7.31	4.15%	$25.00	$732.00	$7.02	1.83%	$25.00
LSC-2	$1,173.84	$3.82	2.90%	$85.00	$1,173.84	$2.47	3.02%	$85.00	$1,173.84	$5.67	6.22%	$25.00	$1,173.84	$6.27	6.22%	$25.00	$1,173.84	$5.98	2.01%	$25.00
LCS-3	$2,418.12	$3.56	3.16%	$85.00	$2,418.12	$2.18	3.39%	$85.00	$2,418.12	$5.38	8.47%	$25.00	$2,418.12	$5.98	8.48%	$25.00	$2,418.12	$5.69	2.08%	$25.00
AGS	$480.00	$3.89	2.91%	$85.00	$480.00	$2.53	3.06%	$85.00	$480.00	$5.73	6.23%	$25.00	$480.00	$6.33	6.23%	$25.00	$480.00	$6.04	1.98%	$25.00

Additional inputs into the net cash inflows calculation are shown below:

Table 3: Net Cash Inflows Economic Parameters[10]

Economic Parameter	FEI					FEVI				
	2008	2009	2010	2011	2012	2008	2009	2010	2011	2012
O&M per Customer										
Residential	$75.00	$75.00	$75.00	$86.00	$84.00	$62.48	$62.48	$62.48	$70.00	$74.00
Commerical	$98.00	$98.00	$98.00	$89.00	$87.00	$86.48	$86.48	$86.48	$85.00	$90.00
System Improvement (SI)	$0.16	$0.16	$0.16	$0.16	$0.36	$0.15	$0.15	$0.15	$0.15	$0.49
Property Tax Rate	1.85%	1.96%	1.96%	1.95%	2.01%	1.80%	1.71%	1.81%	1.86%	1.90%
Income Tax Rate	31.50%	30.00%	28.50%	26.50%	25.00%	31.50%	30.00%	28.50%	26.50%	25.00%

Notes:

- O&M per customer figures for 2012 are from the 2012-2013 RRA.[11]
- Property tax rates are based on actual property tax payments. The changes in income tax rates reflect those included in the RRA.

4.4.2 SYSTEM IMPROVEMENT CHARGE & METHODOLOGY

Prior to 2012, the System Improvement ("SI") charge was calculated once every 5 years; the last SI charge calculation took place in 2007 and was approved in Order G-152-07 along with the methodology to re-visit the SI charge every 5 years. The resulting SI charges for FEI and FEVI of $0.16 per GJ and $0.151 per GJ respectively were applied to all Main Extension Tests from 2007-2011. As agreed upon with Commission Staff, the Companies will be re-calculating the SI charge on an annual basis in order to better capture the changing consumption patterns of customers and to reflect the resulting variability in peak day demand which forms the foundation for the SI charge calculations. Although the calculation methodologies behind the SI charge will remain consistent with past practices, the Companies are in agreement with Commission Staff that re-calculating the SI charge each year will not only reduce vulnerability to forecast error, but will ensure customers are charged a rate that is continuously refined to reflect the current state of the Companies' distribution system. Table 4 below identifies the variances between the 2007/2011 SI charge and the 2012 SI charge.

[10] For this table, FEI Commercial is defined as Rate Schedule 2 and FEVI Commercial applies to all sales customers excluding Residential (RGS)

[11] The FortisBC Energy Utilities 2012- 2013 Revenue Requirements and Rates Application (Commissions approval order G-44-12).

Table 4: SI Charge Calculation

Changes from 2007 - 2011 to 2012 SI Charge

		FEI	
		2007 - 2011	**2012**
A	**Increase to Peak Day over 5 years**	89.5	45.2
B	**System Improvement**	$17,209,119	$16,160,000
C	**Investment Cost per GJ of Peak Capacity** = B / (A x1000)	$ 192.28	$ 357.41
D	**5 Year Average Load Factor**	0.292	0.245
E	**Investment Cost per GJ of Annual Capacity** = C / (365 x D)	$ 1.80	$ 4.00
F	**Carrying Cost per $1,000**	$ 88.83	$ 88.97
G	**Levelized Cost/GJ** = E x (F / 1000)	**$ 0.160**	**$ 0.355**

		FEVI	
		2007 - 2011	**2012**
A	**Increase to Peak Day over 5 years**	17.4	9.4
B	**System Improvement**	$ 3,398,787	$ 5,550,000
C	**Investment Cost per GJ of Peak Capacity** = B / (A x1000)	$ 195.33	$ 588.82
D	**5 Year Average Load Factor**	0.302	0.281
E	**Investment Cost per GJ of Annual Capacity** = C / (365 x D)	$ 1.77	$ 5.74
F	**Carrying Cost per $1,000**	$ 85.08	$ 84.55
G	**Levelized Cost/GJ** = E x (F / 1000)	**$ 0.151**	**$ 0.485**

For the 2012 Main Extension Test, the SI charge was recalculated and resulted in SI charges of $0.36 per GJ and $0.49 per GJ for FEI and FEVI respectively.

The major driver of the change from 2007/2011 to 2012 is the reduction in the "Forecast Increase to Peak Day over 5 years". The Companies' System Planning department uses a forecasted "peak hour" demand to size the system to meet the hourly demand of gas. The "peak hour" demand is then used to determine the system improvement capital. With the installation of newer energy efficient and on-demand heating equipment the actual peak hour flows will likely creep upwards however, the total peak day demand will likely decrease as non-peak hours will use less gas.

The resulting implications are that the system improvement capital does not change significantly but when divided by the lower peak day demand, the investment per GJ of peak day demand increases resulting in a higher SI Charge.

The system improvement capital can also be impacted by the geographical location of the anticipated system expansion requirements. Overall, demand may be down, but the new customers that are being added may be at the edge of the system, and as a result, the Companies would incur more system improvement capital per customer for expansion in outlying areas as compared to previously settled areas.

4.4.3 CONSUMPTION

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"). The consumption figures for 2011 are based on the 2008 REUS which included a regionalized approach to forecasting consumption where usage amounts per appliance are based on the geographic location of a potential customer. The consumption values for 2008 to 2010 are reflective of the 2002 REUS, which assumed a single set of consumption per appliance parameters regardless of location. This data is presented in Table 4.

Table 5: Appliance Use Inputs for MX Test

	2008 - 2010 (GJ/yr)	2011-2012 (GJ/yr)		
Appliance	All Regions	Lower Mainland	Interior	Vancouver Island
Barbeque	3.1	3.1	3.1	3.1
Boiler	60.0	62.0	51.6	43.0
Clothes Dryer	4.0	4.2	3.6	3.4
Fireplace - Décor	15.8	18.3	15.9	16.1
Fireplace - Heating	16.8	21.4	19.8	19.7
Furnace (primary)	60.0	62.0	51.6	43.0
Furnace (secondary)	60.0	18.1	39.3	19.9
Hot Tub	17.9	19.5	19.5	19.5
Hot Water Tank	20.8	20.4	18.8	18.8
Pool	53.5	38.5	38.5	38.5
Range/Cooktop	8.5	5.6	5.1	4.7
Wall Heater	18.1	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.

As per Commission Order No. G-6-08, the Companies are required to confirm that some larger developments, including vertical subdivisions, may require several years before all units are occupied and normal consumption patterns are established. This is accounted for in the forecast. Various considerations go into meeting this requirement including accounting for economic conditions, project forecast from builder/developers and the Companies' expertise and experience in these areas.

As per Commission Order No. G-52-07, the Companies note that consumption "ramp up" is present in their aggregate forecasts. Specifically, the Companies build into selected year 1 consumption forecasts a 'ramp up' factor that reduces year 1 forecasts. The Companies and Commission Staff have agreed that the general use of the 'ramp up' factor, as well as its magnitude, is solely at the discretion of the planner and energy sales expert. The 'ramp up' tool is an option to assist the sales and planning groups with the potential to increase the accuracy of their forecasts. As requested by Commission Staff, the Companies have provided the associated 'ramp-up' factor for each of the top 5 main extensions for both FEI and FEVI.

4.4.4 CAPITAL COSTS

The inputs into the net present value of capital costs in the MX Test formula are discussed in the following section. The capital costs to be used in the economic test are described in Section 12.5(a) and 12.5(b) of the FEI and FEVI GT&Cs (refer to Appendix B).

4.4.4.1 Geo Codes and Manual Estimates

Geographic ("Geo") code and manual estimate pricing are the two methods used to determine main extension costs with approximately 10 percent of MX projects using the manual estimate cost methodology.

The following table illustrates the criteria used by the Companies to determine the requirement to use geo code versus manual estimates.

Table 6: Geo Code & Manual Estimates Criteria

Pipeline Criteria	Geo Code	Manual Estimate
Pressure	Distribution pressure (DP)	Intermediate pressure (IP)
Material	Polyetheleyne (PE)	Steel (ST)
Diameter	Up to 60 mm (2")	88 mm (3.5") and larger for PE and ST
Length	Maximum 1000 m	Greater than 1000 m
Cost	Maximum $100,000	Greater than $100,000
Crossing Type	Road or pipeline only	Direction drills, highway, bridge, water or railway crossing
Environmental impacts	All environmental impacts except fish bearing streams	Environmental impacts of fish bearing streams
Other		Vertical Sub Divisions Conversion Mains Mains in transmission right of ways

Recent geo codes and manual estimate inputs used in the MX Test are as follows:

Table 7: 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
2012	Vancouver & Richmond	$65					
	North Shore & Squamish	$55					
	North of Fraser River	$51					
	South of Fraser River	$43	manual		manual		
	Interior North	$31					
	Interior South	$29					
	Vancouver Island	$50					
2011	Vancouver & Richmond	$65					
	North Shore & Squamish	$56					
	North of Fraser River	$43					
	South of Fraser River	$42	manual		manual		
	Interior North	$33					
	Interior South	$23					
	Vancouver Island	$55					
2010	Vancouver & Richmond	$83	$141	$227	$208	$353	$566
	North Shore & Squamish	$55	$94	$150	$138	$234	$375
	North of Fraser River	$56	$95	$153	$140	$238	$382
	South of Fraser River	$47	$80	$128	$118	$200	$321
	Interior North	$35	$60	$96	$88	$149	$239
	Interior South	$26	$44	$71	$65	$111	$177
	Vancouver Island	$50	$85	$137	$125	$213	$341
2009	Vancouver & Richmond	$59	$84	$162	$148	$211	$405
	North Shore & Squamish	$54	$77	$148	$136	$192	$370
	North of Fraser River	$62	$88	$169	$154	$219	$422
	South of Fraser River	$40	$56	$108	$99	$140	$270
	Interior North	$27	$39	$74	$68	$96	$185
	Interior South	$28	$40	$77	$71	$101	$193
	Vancouver Island	$61	$87	$167	$153	$218	$419
2008	Vancouver & Richmond	$58	$99	$158	$145	$247	$394
	North Shore & Squamish	$60	$103	$165	$151	$258	$412
	North of Fraser River	$40	$68	$109	$100	$170	$272
	South of Fraser River	$40	$69	$110	$101	$172	$275
	Interior North	$26	$44	$71	$65	$111	$177
	Interior South	$26	$44	$71	$65	$111	$177
	Vancouver Island South	$66	$113	$181	$166	$284	$453
	Vancouver Island North	$41	$70	$111	$102	$174	$279

Notes:

- The geo code variance in the table above is attributable to the use of linear regression on historical main extension cost data (geo codes are derived by performing linear regression on historical cost data).

The capital cost portion of the MX Test formula includes economic parameter inputs used for all rate classes. The relevant parameters are summarized below:

Table 8: Capital Cost Economic Parameters

	FEI					FEVI				
Economic Parameter	**2008**	**2009**	**2010**	**2011**	**2012**	**2008**	**2009**	**2010**	**2011**	**2012**
Overhead Rate	32.00%	32.00%	32.00%	30.00%	27.40%	32.00%	32.00%	32.00%	30.00%	27.40%
CCA Class 1	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Working Capital Rate	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%

Notes:

- As seen above, in 2012 the Companies updated the applicable overhead figures to reflect data available from the RRAs. This overhead rate represents applicable costs required in support of new mains activities and is reflective of the Companies' current cost structure and overhead capitalization.

4.4.5 DISCOUNT RATE

The discount rates used for 2012 were 5.0 percent for FEI and 4.6 percent for FEVI. The discount rates reflect the capital structure of each company and the relative borrowing costs and allowed ROE (Commission Order No. G-44-12), as per the Companies' respective RRAs. For each year, the discount rates were adjusted to real dollars using an inflation factor of 2 percent.

The following section provides discusses the methodologies and challenges associated with the three pillars of the MX Test, consumption, attachments and costs.

5 MAIN EXTENSTON TEST FORECASTING METHODOLOGIES

The Companies place paramount importance on incorporating fair and reasonable forecasting methodologies used in the Main Extension Test. The Companies are committed to effectively managing the inherent variability between forecast and actuals of the three cornerstones of the PI calculation, namely consumption, attachments and cost. This section provides a high level summary of the challenges faced when attempting to forecast consumption, attachments and cost and the Companies' efforts to manage the variability. This section also serves as an introduction to the significant volume of data that follows and provides an efficient overview of common themes that apply to MX projects in general.

5.1 Customer Consumption

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. For example, although a developer may plan to install identical appliances for each home in a subdivision, the individual customers who purchase those homes will have their own unique usage patterns which add to the uncertainty in forecasting. In addition, the type of appliances installed can also result in differences between forecasted and actual consumption of each customer. A convenience hookup such as barbeque may have a wider consumption variation between customers than two customers that have a primary heat source appliance such as a furnace (assuming those premises are not vacation properties or properties that also have other sources of heating). The Companies also have very little control over fuel switching, where a customer may choose to easily install an electric fireplace in a high usage room rather than utilize the furnace to heat the entire home. 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 would be subject to significant variation from the forecast if just one of the larger commercial customers fails to connect given that the usage of a large business is generally much greater than several single-family dwellings.

Neither builders nor the Companies have control over the usage rate of the end use customer. Builders only have control over the installation of the natural gas appliance. *The usage rates of new end-users can be highly variable. Similarly, existing customers change their load and usage profiles over time as a result of changing equipment or moving from one form of energy to another for a specific appliance (i.e., electric stove to gas stove or vice versa) or through the changing demographics of the household in the event the home is re-sold*. These existing customers are not penalized for changing their load profiles; on the contrary, through Energy Efficiency and Conservation Programs ("EEC"), these customers are actually encouraged to use less than what they previously used. In this manner, it is inconsistent, and unequal from an intergenerational standpoint, to hold new customers/developers to a different standard than existing customers.

In the past, when performing the MX Test, the Companies have utilized a single average consumption value (dependent on the appliances) for each connection based on results from the 2002 REUS. However, the 2008 REUS included findings that prompted the Commission's decision to direct the Companies to move to a regionalized approach to consumption, where a customer's forecasted consumption would be contingent upon their appliances as well as where they lived and was based on the average consumption of all existing customers at that time. In Table 4 for example, the appliance use inputs for 2008-2010 years are based on 2002 REUS where 100 GJs of annual consumption would have been considered normal usage for a customer with a furnace, hot water tank and a fireplace regardless of where they lived. However, the 2008 REUS regionalized approach adopted in 2011, resulted in a reduction for a typical Vancouver Island resident to 75 GJs per year. This change in methodology has been in place since 2011 and will be reflected in the results of future MX Reports.

A primary deliverable of the 2012 REUS, which is currently underway, will be an in-depth analysis of the regional consumption forecasting methods currently employed by the Companies. For example, the consumption pattern of a new customer compared to current customer with the same appliances will differ because of continuously improving technology and energy efficiency. It is anticipated that the 2012 REUS will show a decline in the regionalized appliance-based consumption patterns of the average FEI and FEVI residential customer based on the addition of new energy efficient customers over the past few years. The Companies will be working through the analysis phase of the 2012 REUS data throughout the second and third quarter of 2013, with final results anticipated to be ready for review during the fourth quarter of 2013.

The Companies residential consumption forecasts are based on the best available data available at the time of formulation, and as such, will be updated based on feedback and approval from Commission Staff on the findings of the 2012 REUS. *However, even with a more robust REUS, the Companies continue to believe that there will be a disconnect between new and existing customers in terms main extension test inputs such as consumption, PI results, and overall policy impacts.*

5.2 Attachments

The primary contributor to the cash inflows of the Main Extension Test is the number of attachments or "services", and their related consumption levels. It is important to note, however, that without associated consumption, a service attachment contributes only to the cost portion of a main extension. For example, if a developer had built and attached new homes to the system, and, due to economic conditions, faced delays in selling those homes, the PI, at that snapshot in time moment, of the main extension would actually be lower than if the homes had not been built at all. In other words, the costs incurred by the Companies for the service connections would not yet be offset by consumption.

In general, the developer provides a good-faith estimate of the future attachments and appliances to be installed in a main extension project. The developers use their knowledge and experience, along with FEI/FEVI knowledge and experience to finalize these forecasted customer/appliance attachments. However, in certain instances where there is concern over the forecasts, a security deposit may be obtained from the developer (as per GT&Cs Section 12.9) which may be retained by FEI/FEVI, although this is very infrequent.

Both the timing and number of attachments in any main extension project contain the most uncertainty. In most instances, the number of homes that a developer plans to build will be significantly impacted by a multitude of external factors such as the economy, housing market, interest rates, labour market, cost of materials and planning and development issues. For example, a developer, due to economic conditions, may reduce the number of homes to be built after the completion of the main extension. These same issues are present for other utilities such as water, and electricity, and although the Companies work closely with the developer in determining forecasts, the number of unknown factors involved result in forecasted attachments that will inevitably be variable from the actuals on a yearly basis. However, over the life of the asset, the Company expects that the forecast attachments will materialize.

5.3 Mains Cost

There are two key components which contribute to the costs portion of the Main Extension Test, the mains cost and service cost. The mains cost accounts for the majority of the total cost of a project and would include a full scope of expenses such as planning, materials and labour. The service line costs generally contribute much less to a project's final cost, but their impact would increase in projects such as a residential subdivision where a developer plans to install a large number of homes. Both the mains and service line costs are discussed below.

As will be seen in the data tables in the 2012 MX Report, the MX Test element that has the least amount of variability is the cost of the main extension. In the past, the original forecast mechanism for determining main extension costs was a single Geo-Price based approach where the cost per meter was essentially derived from the geographic location of the main and the environmental characteristics of that area. However, the Companies still saw variability between the forecast and the actuals in those projects that included special characteristics such as a bridge or water crossing, larger size main, higher pressure requirements. To better capture the cost differences associated with these features, the Companies introduced in 2010 a pilot set of Manual Estimate criteria which were fully implemented in 2011 and are now used as an alternative to the Geo-Price method. These criteria are provided in the Geo Codes and Manual Estimates tables of this Report. For the small percentage of main extensions (approximately 10 percent) 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 Companies' service provider. In other words, the Planner uses the same criteria for cost projections as those actually performing the construction of these projects. As a result, the historic and current variances between the forecasted and actual main costs have been relatively minor and are reflected in the aggregate sample results throughout this MX Report.

5.4 Service Cost

The Companies have also employed the Geo-Price based approach when estimating the cost of a new service line. However, the service cost estimates will generally have a greater level of variance than the mains cost. For example, each attachment or "lot" in new subdivision would have its own unique set of characteristics, such as ground cover, soil type, lot size, and service line distance. As such, the variance between forecast and actual service line costs can be expected to be relatively high.

As described above in Section 3.3, the introduction of a Manual Estimate approach used in conjunction with Geo-Prices has helped to minimize the variances between forecasted and actual service line costs. Although the variances contained in this Report are reasonable, due to unforeseen circumstances such as rocky ground cover, conflicts with foreign utilities and changes made by the developer, there will always be a variance between the forecast and actual service line costs.

6 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 first year of actual results for this section will appear in the 2013 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 2012 main extension data tables as well as future report tables reflect the expanded rate class breakdown as discussed in Section 1.

6.1 2012 FEI Random Sample Results

The tables below summarize the sample aggregate 2012 main extension results for FEI.

Table 9: 2012 FEI Aggregate Main Extensions Costs

2012 SAMPLE MAIN EXTENSIONS - COSTS				
FEI	Cost of Installation ($)			
		Original Forecast	Actual	Variance %
Year 1	Mains	$ 585,584	$ 644,832	10%
	Service lines and meters	$ 246,400	$ -	-100%
	Year 1 Total	$ 831,984	$ 644,832	-22%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 106,805	$ -	-100%
	Year 2 Total	$ 106,805	$ -	-100%
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**	**$644,832**	**-45%**

Table 10: 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**	**263**	**0%**	**101,576**	**101,576**	**0%**	**386**	**386**	**0%**
Rate 1	*173*	*173*	*0%*	*20,640*	*20,640*	*0%*	*119*	*119*	*0%*
Rate 2	*88*	*88*	*0%*	*41,307*	*41,307*	*0%*	*469*	*469*	*0%*
Rate 3	*2*	*2*	*0%*	*39,629*	*39,629*	*0%*	*19,815*	*19,815*	*0%*
Year 2	**377**	**377**	**0%**	**111,841**	**111,841**	**0%**	**297**	**297**	**0%**
Rate 1	*270*	*270*	*0%*	*29,246*	*29,246*	*0%*	*108*	*108*	*0%*
Rate 2	*105*	*105*	*0%*	*42,966*	*42,966*	*0%*	*409*	*409*	*0%*
Rate 3	*2*	*2*	*0%*	*39,629*	*39,629*	*0%*	*19,815*	*19,815*	*0%*
Year 3	**483**	**483**	**0%**	**122,484**	**122,484**	**0%**	**254**	**254**	**0%**
Rate 1	*373*	*373*	*0%*	*37,536*	*37,536*	*0%*	*101*	*101*	*0%*
Rate 2	*108*	*108*	*0%*	*45,319*	*45,319*	*0%*	*420*	*420*	*0%*
Rate 3	*2*	*2*	*0%*	*39,629*	*39,629*	*0%*	*19,815*	*19,815*	*0%*
Year 4	**565**	**565**	**0%**	**129,157**	**129,157**	**0%**	**229**	**229**	**0%**
Rate 1	*452*	*452*	*0%*	*41,856*	*41,856*	*0%*	*93*	*93*	*0%*
Rate 2	*111*	*111*	*0%*	*47,672*	*47,672*	*0%*	*429*	*429*	*0%*
Rate 3	*2*	*2*	*0%*	*39,629*	*39,629*	*0%*	*19,815*	*19,815*	*0%*
Year 5	**620**	**620**	**0%**	**135,819**	**135,819**	**0%**	**219**	**219**	**0%**
Rate 1	*496*	*496*	*0%*	*45,452*	*45,452*	*0%*	*92*	*92*	*0%*
Rate 2	*122*	*122*	*0%*	*50,738*	*50,738*	*0%*	*416*	*416*	*0%*
Rate 3	*2*	*2*	*0%*	*39,629*	*39,629*	*0%*	*19,815*	*19,815*	*0%*
Years 1-5 Total	**620**	**620**	**0%**	**600,877**	**600,877**	**0%**	**219**	**219**	**0%**

Table 11: 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	2.37	-2%
Years 1-5 Total	**2.41**	**2.37**	**-2%**

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.

1 **6.2 2012 FEVI Random Sample Results**

2 The tables below summarize the sample aggregate 2012 main extension results for FEVI.

3 **Table 12: 2012 FEVI Aggregate Main Extensions Costs**

4

2012 SAMPLE MAIN EXTENSIONS - COSTS				
	Cost of Installation ($)			
FEVI		Original Forecast	Actual	Variance %
Year 1	Mains	$ 367,763	$ 350,279	-5%
	Service lines and meters	$ 109,251	$ -	-100%
	Year 1 Total	$ 477,014	$ 350,279	-27%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 38,486	$ -	-100%
	Year 2 Total	$ 38,486	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 28,554	$ -	-100%
	Year 3 Total	$ 28,554	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 12,415	$ -	-100%
	Year 4 Total	$ 12,415	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 12,415	$ -	-100%
	Year 5 Total	$ 12,415	$ -	-100%
Years 1-5 Total		**$568,885**	**$350,279**	**-38%**

Table 13: 2012 FEVI 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		
FEVI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	88	88	0%	9,725	9,725	0%	111	111	0%
Rate 1	78	78	0%	4,210	4,210	0%	54	54	0%
Rate 2	5	5	0%	710	710	0%	142	142	0%
Rate 3	5	5	0%	4,805	4,805	0%	961	961	0%
Year 2	119	119	0%	11,362	11,362	0%	95	95	0%
Rate 1	109	109	0%	5,847	5,847	0%	54	54	0%
Rate 2	5	5	0%	710	710	0%	142	142	0%
Rate 3	5	5	0%	4,805	4,805	0%	961	961	0%
Year 3	142	142	0%	13,010	13,010	0%	92	92	0%
Rate 1	131	131	0%	7,295	7,295	0%	56	56	0%
Rate 2	6	6	0%	910	910	0%	152	152	0%
Rate 3	5	5	0%	4,805	4,805	0%	961	961	0%
Year 4	152	152	0%	13,475	13,475	0%	89	89	0%
Rate 1	141	141	0%	7,760	7,760	0%	55	55	0%
Rate 2	6	6	0%	910	910	0%	152	152	0%
Rate 3	5	5	0%	4,805	4,805	0%	961	961	0%
Year 5	162	162	0%	13,805	13,805	0%	85	85	0%
Rate 1	151	151	0%	8,090	8,090	0%	54	54	0%
Rate 2	6	6	0%	910	910	0%	152	152	0%
Rate 3	5	5	0%	4,805	4,805	0%	961	961	0%
Years 1-5 Total	162	162	0%	61,377	61,377	0%	85	85	0%

Table 14: 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	1.43	3%
Years 1-5 Total	1.39	1.43	3%

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.

6.3 2012 FEI Top 5 Results

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 15 & 16	Table 17 & 18	Table 19 & 20	Table 21 & 22	Table 23 & 24	Table 25
201 Street	Pandosy Street	E. Kent Avenue	Cordova Way	Fremont Street	Top 5 PI Results

Table 15: 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	$ -	-100%
	Year 1 Total	$ 43,068	$ 73,935	72%
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	$73,935	68%

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 16: 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**	**1**	**0%**	**1,998**	**1,998**	**0%**	**1,998**	**1,998**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*1*	*1*	*0%*	*1,998*	*1,998*	*0%*	*1,998*	*1,998*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**2**	**2**	**0%**	**3,996**	**3,996**	**0%**	**1,998**	**1,998**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*3,996*	*3,996*	*0%*	*1,998*	*1,998*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**2**	**2**	**0%**	**3,996**	**3,996**	**0%**	**1,998**	**1,998**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*3,996*	*3,996*	*0%*	*1,998*	*1,998*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**2**	**2**	**0%**	**3,996**	**3,996**	**0%**	**1,998**	**1,998**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*3,996*	*3,996*	*0%*	*1,998*	*1,998*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**2**	**2**	**0%**	**3,996**	**3,996**	**0%**	**1,998**	**1,998**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*3,996*	*3,996*	*0%*	*1,998*	*1,998*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**2**	**2**	**0%**	**17,982**	**17,982**	**0%**	**1,998**	**1,998**	**0%**	

Table 17: 2012 FEI Top 5 – Pandosy Street Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550004072	Pandosy Street	Original Forecast	Actual	Variance %
Year 1	Mains	$ 60,000	$ 54,841	-9%
	Service lines and meters	$ 937	$ -	-100%
	Year 1 Total	$ 60,937	$ 54,841	-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		**$60,937**	**$54,841**	**-10%**

Table 18: 2012 FEI Top 5 – Pandosy 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			
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**	**1**	**0%**	**36,864**	**36,864**	**0%**	**36,864**	**36,864**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*1*	*0%*	*36,864*	*36,864*	*0%*	*36,864*	*36,864*	*0%*	
Year 2	**1**	**1**	**0%**	**36,864**	**36,864**	**0%**	**36,864**	**36,864**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*1*	*0%*	*36,864*	*36,864*	*0%*	*36,864*	*36,864*	*0%*	
Year 3	**1**	**1**	**0%**	**36,864**	**36,864**	**0%**	**36,864**	**36,864**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*1*	*0%*	*36,864*	*36,864*	*0%*	*36,864*	*36,864*	*0%*	
Year 4	**1**	**1**	**0%**	**36,864**	**36,864**	**0%**	**36,864**	**36,864**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*1*	*0%*	*36,864*	*36,864*	*0%*	*36,864*	*36,864*	*0%*	
Year 5	**1**	**1**	**0%**	**36,864**	**36,864**	**0%**	**36,864**	**36,864**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*1*	*1*	*0%*	*36,864*	*36,864*	*0%*	*36,864*	*36,864*	*0%*	
Years 1-5 Total	**1**	**1**	**0%**	**184,320**	**184,320**	**0%**	**36,864**	**36,864**	**0%**	

Table 19: 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	$ -	-100%
	Year 1 Total	$ 81,955	$ 77,867	-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		$81,955	$77,867	-5%

Table 20: 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**	**16**	**0%**	**4,864**	**4,864**	**0%**	**304**	**304**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*16*	*0%*	*4,864*	*4,864*	*0%*	*304*	*304*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**16**	**16**	**0%**	**4,864**	**4,864**	**0%**	**304**	**304**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*16*	*0%*	*4,864*	*4,864*	*0%*	*304*	*304*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**16**	**16**	**0%**	**4,864**	**4,864**	**0%**	**304**	**304**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*16*	*0%*	*4,864*	*4,864*	*0%*	*304*	*304*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**16**	**16**	**0%**	**4,864**	**4,864**	**0%**	**304**	**304**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*16*	*0%*	*4,864*	*4,864*	*0%*	*304*	*304*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**16**	**16**	**0%**	**4,864**	**4,864**	**0%**	**304**	**304**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*16*	*16*	*0%*	*4,864*	*4,864*	*0%*	*304*	*304*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**16**	**16**	**0%**	**24,320**	**24,320**	**0%**	**304**	**304**	**0%**	

Table 21: 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	$ -	-100%
	Year 1 Total	$ 143,094	$ 102,168	-29%
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	$102,168	-33%

Table 22: 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**	**3**	**0%**	**1,050**	**1,050**	**0%**	**350**	**350**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*3*	*3*	*0%*	*1,050*	*1,050*	*0%*	*350*	*350*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**6**	**6**	**0%**	**2,182**	**2,182**	**0%**	**364**	**364**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*6*	*6*	*0%*	*2,182*	*2,182*	*0%*	*364*	*364*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**9**	**9**	**0%**	**3,282**	**3,282**	**0%**	**365**	**365**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*9*	*9*	*0%*	*3,282*	*3,282*	*0%*	*365*	*365*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**10**	**10**	**0%**	**3,682**	**3,682**	**0%**	**368**	**368**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*10*	*10*	*0%*	*3,682*	*3,682*	*0%*	*368*	*368*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**12**	**12**	**0%**	**4,482**	**4,482**	**0%**	**374**	**374**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*12*	*12*	*0%*	*4,482*	*4,482*	*0%*	*374*	*374*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**12**	**12**	**0%**	**14,678**	**14,678**	**0%**	**374**	**374**	**0%**	

Table 23: 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	$ 87,235	-7%
	Service lines and meters	$ 1,874	$ -	-100%
	Year 1 Total	$ 95,920	$ 87,235	-9%
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	$87,235	-17%

Table 24: 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	Attachments			Consumption (GJ)			Use per Customer			
5550005794 Fremont 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	**2**	**2**	**0%**	**1,421**	**1,421**	**0%**	**711**	**711**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*1,421*	*1,421*	*0%*	*711*	*711*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**3**	**3**	**0%**	**2,078**	**2,078**	**0%**	**693**	**693**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*3*	*3*	*0%*	*2,078*	*2,078*	*0%*	*693*	*693*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**6**	**6**	**0%**	**4,431**	**4,431**	**0%**	**739**	**739**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*6*	*6*	*0%*	*4,431*	*4,431*	*0%*	*739*	*739*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**9**	**9**	**0%**	**6,784**	**6,784**	**0%**	**754**	**754**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*9*	*9*	*0%*	*6,784*	*6,784*	*0%*	*754*	*754*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**12**	**12**	**0%**	**9,137**	**9,137**	**0%**	**761**	**761**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*12*	*12*	*0%*	*9,137*	*9,137*	*0%*	*761*	*761*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**12**	**12**	**0%**	**23,851**	**23,851**	**0%**	**761**	**761**	**0%**	

1
2 **Table 25: 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	0.89	-40%
Pandosy Street	9.20	10.04	9%
E Kent Avenue	1.55	1.35	-13%
Cordova Way	0.80	0.71	-11%
Fremont Street	0.98	1.15	17%
Years 1-5 Total	**1.48**	**0.89**	**-40%**

3

4 6.4 2012 FEVI Top 5 Results

5 The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 26 & 27	Table 28 & 29	Table 30 & 31	Table 32 & 33	Table 34 & 35	Table 36
Arbot Road	Small Road	Rutherford Road	Bowen Road	Delamere Road	Top 5 PI Results

6

Table 26: 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	$ 3,724	$ -	-100%
	Year 1 Total	$ 112,462	$ 128,245	14%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 6,207	$ -	-100%
	Year 2 Total	$ 6,207	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 6,207	$ -	-100%
	Year 3 Total	$ 6,207	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 8,690	$ -	-100%
	Year 4 Total	$ 8,690	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 6,207	$ -	-100%
	Year 5 Total	$ 6,207	$ -	-100%
Years 1-5 Total		$139,775	$128,245	-8%

Table 27: 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**	**3**	**0%**	**150**	**150**	**0%**	**50**	**50**	**0%**	
Rate 1	*3*	*3*	*0%*	*150*	*150*	*0%*	*50*	*50*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**8**	**8**	**0%**	**400**	**400**	**0%**	**50**	**50**	**0%**	
Rate 1	*8*	*8*	*0%*	*400*	*400*	*0%*	*50*	*50*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**13**	**13**	**0%**	**650**	**650**	**0%**	**50**	**50**	**0%**	
Rate 1	*13*	*13*	*0%*	*650*	*650*	*0%*	*50*	*50*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**20**	**20**	**0%**	**1,000**	**1,000**	**0%**	**50**	**50**	**0%**	
Rate 1	*20*	*20*	*0%*	*1,000*	*1,000*	*0%*	*50*	*50*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**25**	**25**	**0%**	**1,250**	**1,250**	**0%**	**50**	**50**	**0%**	
Rate 1	*25*	*25*	*0%*	*1,250*	*1,250*	*0%*	*50*	*50*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**25**	**25**	**0%**	**3,450**	**3,450**	**0%**	**50**	**50**	**0%**	

Table 28: 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	$ 1,241	$ -	-100%
	Year 1 Total	$ 24,591	$ 29,972	22%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 2 Total	$ -	$ -	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 1,241	$ -	-100%
	Year 3 Total	$ 1,241	$ -	-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		$25,833	$29,972	16%

Notes:

- A directional drill underneath a Highway and extra depth requirements resulted in driving actual costs higher than forecast.

Table 29: 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**	**288**	**0%**	**288**	**288**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*1*	*1*	*0%*	*288*	*288*	*0%*	*288*	*288*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**1**	**1**	**0%**	**288**	**288**	**0%**	**288**	**288**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*1*	*1*	*0%*	*288*	*288*	*0%*	*288*	*288*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**2**	**2**	**0%**	**488**	**488**	**0%**	**244**	**244**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*488*	*488*	*0%*	*244*	*244*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**2**	**2**	**0%**	**488**	**488**	**0%**	**244**	**244**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*488*	*488*	*0%*	*244*	*244*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**2**	**2**	**0%**	**488**	**488**	**0%**	**244**	**244**	**0%**	
Rate 1	*0*	*0*		*0*	*0*					
Rate 2	*2*	*2*	*0%*	*488*	*488*	*0%*	*244*	*244*	*0%*	
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**2**	**2**	**0%**	**2,040**	**2,040**	**0%**	**244**	**244**	**0%**	

Table 30: 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	$ 12,415	$ -	-100%
	Year 1 Total	$ 64,940	$ 62,901	-3%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 14,898	$ -	-100%
	Year 2 Total	$ 14,898	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 9,932	$ -	-100%
	Year 3 Total	$ 9,932	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 9,932	$ -	-100%
	Year 4 Total	$ 9,932	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 12,415	$ -	-100%
	Year 5 Total	$ 12,415	$ -	-100%
Years 1-5 Total		$112,117	$62,901	-44%

Table 31: 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**	**10**	**0%**	**396**	**396**	**0%**	**40**	**40**	**0%**	
Rate 1	*10*	*10*	*0%*	*396*	*396*	*0%*	*40*	*40*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**22**	**22**	**0%**	**1,004**	**1,004**	**0%**	**46**	**46**	**0%**	
Rate 1	*22*	*22*	*0%*	*1,004*	*1,004*	*0%*	*46*	*46*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**30**	**30**	**0%**	**1,321**	**1,321**	**0%**	**44**	**44**	**0%**	
Rate 1	*30*	*30*	*0%*	*1,321*	*1,321*	*0%*	*44*	*44*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**38**	**38**	**0%**	**1,638**	**1,638**	**0%**	**43**	**43**	**0%**	
Rate 1	*38*	*38*	*0%*	*1,638*	*1,638*	*0%*	*43*	*43*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**48**	**48**	**0%**	**2,034**	**2,034**	**0%**	**42**	**42**	**0%**	
Rate 1	*48*	*48*	*0%*	*2,034*	*2,034*	*0%*	*42*	*42*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**48**	**48**	**0%**	**6,393**	**6,393**	**0%**	**42**	**42**	**0%**	

Table 32: 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	$ 17,381	$ -	-100%
	Year 1 Total	$ 48,901	$ 31,041	-37%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 12,415	$ -	-100%
	Year 2 Total	$ 12,415	$ -	-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		**$61,316**	**$31,041**	**-49%**

Table 33: 2012 FEVI Top 5 – Bowen 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			
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**	**14**	**0%**	**420**	**420**	**0%**	**30**	**30**	**0%**	
Rate 1	*14*	*14*	*0%*	*420*	*420*	*0%*	*30*	*30*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	**24**	**24**	**0%**	**720**	**720**	**0%**	**30**	**30**	**0%**	
Rate 1	*24*	*24*	*0%*	*720*	*720*	*0%*	*30*	*30*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	**24**	**24**	**0%**	**720**	**720**	**0%**	**30**	**30**	**0%**	
Rate 1	*24*	*24*	*0%*	*720*	*720*	*0%*	*30*	*30*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	**24**	**24**	**0%**	**720**	**720**	**0%**	**30**	**30**	**0%**	
Rate 1	*24*	*24*	*0%*	*720*	*720*	*0%*	*30*	*30*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	**24**	**24**	**0%**	**720**	**720**	**0%**	**30**	**30**	**0%**	
Rate 1	*24*	*24*	*0%*	*720*	*720*	*0%*	*30*	*30*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	**24**	**24**	**0%**	**3,300**	**3,300**	**0%**	**30**	**30**	**0%**	

Table 34: 2012 FEVI Top 5 – Delamere Road Costs

2012 TOP 5 MAIN EXTENSIONS - COSTS		Cost of Installation ($)		
FEVI				
5550006162	Delamere Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 13,558	$ 33,830	150%
	Service lines and meters	$ 3,724	$ -	-100%
	Year 1 Total	$ 17,282	$ 33,830	96%
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		$17,282	$33,830	96%

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 35: 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	3	0%	190	190	0%	63	63	0%	
Rate 1	*3*	*3*	*0%*	*190*	*190*	*0%*	*63*	*63*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 2	3	3	0%	190	190	0%	63	63	0%	
Rate 1	*3*	*3*	*0%*	*190*	*190*	*0%*	*63*	*63*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 3	3	3	0%	190	190	0%	63	63	0%	
Rate 1	*3*	*3*	*0%*	*190*	*190*	*0%*	*63*	*63*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 4	3	3	0%	190	190	0%	63	63	0%	
Rate 1	*3*	*3*	*0%*	*190*	*190*	*0%*	*63*	*63*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Year 5	3	3	0%	190	190	0%	63	63	0%	
Rate 1	*3*	*3*	*0%*	*190*	*190*	*0%*	*63*	*63*	*0%*	
Rate 2	*0*	*0*		*0*	*0*					
Rate 3	*0*	*0*		*0*	*0*					
Years 1-5 Total	3	3	0%	950	950	0%	63	63	0%	

1
2 **Table 36: 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	0.39	-51%
Small Road	1.31	1.06	-19%
Rutherford Road	0.92	0.85	-8%
Bowen Road	0.80	0.81	1%
Delamere Road	0.80	0.21	-73%
Years 1-5 Total	**0.80**	**0.39**	**-51%**

3
4

7 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, 2011.
- 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.

7.1 2011 FEI Random Sample Results

The tables below summarize the sample aggregate 2011 main extension results for FEI.

Table 37: 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	$ 644,910	55%
	Year 1 Total	$ 1,049,516	$ 1,372,435	31%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 165,872	$ -	-100%
	Year 2 Total	$ 165,872	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 109,405	$ -	-100%
	Year 3 Total	$ 109,405	$ -	-100%
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	$1,372,435	-7%

Table 38: 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	415	18%	45,968	43,369	-6%	130	105	-20%
Year 2	494	556	13%	59,622	57,023	-4%	121	103	-15%
Year 3	587	649	11%	68,784	66,185	-4%	117	102	-13%
Year 4	638	700	10%	73,054	70,455	-4%	115	101	-12%
Year 5	715	777	9%	87,574	84,975	-3%	122	109	-11%
Years 1-5 Total	**715**	**777**	**9%**	**335,002**	**322,009**	**-4%**	**122**	**109**	**-11%**

Table 39: 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 Year 4 Year 5	1.39	1.03	-26%
Years 1-5 Total	**1.39**	**1.03**	**-26%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[12].
- 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.

7.2 2011 FEVI Random Sample Results

The tables below summarize the sample aggregate 2011 main extension results for FEVI.

[12] FEI & FEVI Main Extension Report for 2011 Year End, submitted to the Commission July 31, 2012.

Table 40: 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	$ 188,032	-4%
	Year 1 Total	$ 709,683	$ 745,248	5%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 93,849	$ -	-100%
	Year 2 Total	$ 93,849	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 41,579	$ -	-100%
	Year 3 Total	$ 41,579	$ -	-100%
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**	**$745,248**	**-13%**

Table 41: 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	128	-22%	15,038	21,673	44%	91	169	86%
Year 2	244	207	-15%	18,246	24,881	36%	75	120	61%
Year 3	279	242	-13%	19,495	26,130	34%	70	108	55%
Year 4	285	248	-13%	19,709	26,344	34%	69	106	54%
Year 5	291	254	-13%	19,958	26,593	33%	69	105	53%
Years 1-5 Total	**291**	**254**	**-13%**	**92,446**	**125,620**	**36%**	**69**	**105**	**53%**

Table 42: 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	1.68	26%
Years 1-5 Total	**1.33**	**1.68**	**26%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[13].
- 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.

7.3 2011 FEI Top 5 Results

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 43 & 44	Table 45 & 46	Table 47 & 48	Table 49 & 50	Table 51 & 52	Table 53
96 Avenue	Harper Road	Townshipline Road	Sammet Road	1st Avenue	Top 5 PI Results

13 FEI & FEVI Main Extension Report for 2011 Year End, submitted to the Commission July 31, 2012.

Table 43: 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	$ 3,108	164%
	Year 1 Total	$ 70,769	$ 78,062	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**	**$78,062**	**9%**

Table 44: 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	10,143	-10%	11,271	5,071	-55%	
Year 2	2	3	50%	22,454	21,326	-5%	11,227	7,109	-37%	
Year 3	2	3	50%	22,454	21,326	-5%	11,227	7,109	-37%	0%
Year 4	2	3	50%	22,454	21,326	-5%	11,227	7,109	-37%	
Year 5	2	3	50%	22,454	21,326	-5%	11,227	7,109	-37%	
Years 1-5 Total	**2**	**3**	**50%**	**101,087**	**95,446**	**-6%**	**11,227**	**7,109**	**-37%**	

Table 45: 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	$ 82,362	204%
	Year 1 Total	$ 125,494	$ 156,194	24%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 27,057	$ -	-100%
	Year 2 Total	$ 27,057	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 27,057	$ -	-100%
	Year 3 Total	$ 27,057	$ -	-100%
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**	**$156,194**	**-33%**

Table 46: 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	3,365	47%	100	63	-36%	0%
Year 2	46	76	65%	4,584	5,657	23%	100	74	-25%	
Year 3	69	99	43%	6,876	7,949	16%	100	80	-19%	
Year 4	92	122	33%	9,168	10,241	12%	100	84	-16%	
Year 5	115	145	26%	11,460	12,533	9%	100	86	-13%	
Years 1-5 Total	**115**	**145**	**26%**	**34,380**	**39,743**	**16%**	**100**	**86**	**-13%**	

Table 47: 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	$ 1,554	32%
	Year 1 Total	$ 28,399	$ 50,409	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**	**$50,409**	**78%**

Table 48: 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	11,201	1845%	576	11,201	1845%	
Year 2	1	1	0%	576	11,201	1845%	576	11,201	1845%	0%
Year 3	1	1	0%	576	11,201	1845%	576	11,201	1845%	
Year 4	1	1	0%	576	11,201	1845%	576	11,201	1845%	
Year 5	1	1	0%	576	11,201	1845%	576	11,201	1845%	
Years 1-5 Total	**1**	**1**	**0%**	**2,880**	**56,005**	**1845%**	**576**	**11,201**	**1845%**	

Notes:

- Customer is classified as a Rate 3 (Greenhouse) with consumption levels reflecting an expansion of original project requirements.

Table 49: 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	$ 3,108	32%
	Year 1 Total	$ 61,822	$ 26,938	-56%
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**	**$26,938**	**-56%**

Table 50: 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	2	0%	610	1,192	95%	305	596	95%	
Year 2	2	2	0%	610	1,192	95%	305	596	95%	
Year 3	2	2	0%	610	1,192	95%	305	596	95%	**0%**
Year 4	2	2	0%	610	1,192	95%	305	596	95%	
Year 5	2	2	0%	610	1,192	95%	305	596	95%	
Years 1-5 Total	**2**	**2**	**0%**	**3,050**	**5,961**	**95%**	**305**	**596**	**95%**	

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 51: 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	$ 3,108	32%
	Year 1 Total	$ 41,057	$ 17,731	-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**	**$17,731**	**-57%**

Table 52: 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	219	-11%	123	110	-11%	
Year 2	2	2	0%	245	219	-11%	123	110	-11%	0%
Year 3	2	2	0%	245	219	-11%	123	110	-11%	
Year 4	2	2	0%	245	219	-11%	123	110	-11%	
Year 5	2	2	0%	245	219	-11%	123	110	-11%	
Years 1-5 Total	**2**	**2**	**0%**	**1,225**	**1,095**	**-11%**	**123**	**110**	**-11%**	

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.

1 **Table 53: 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	3.54	-15%
Harper Rd	1.15	0.97	-15%
Townshipline Road	0.83	3.16	281%
Sammet Rd	0.80	0.81	1%
1st Avenue	0.80	0.22	-72%
Years 1-5 Total	**1.55**	**1.74**	**12%**

2

3 ## 7.1 2011 FEVI Top 5 Results

4 The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 54 & 55	Table 56 & 57	Table 58 & 59	Table 60 & 61	Table 62 & 63	Table 64
Englewood Road	Mountain Heights Road	Sooke Road	Veteran's Memorial Parkway	Latoria Road	Top 5 PI Results

5

Table 54: 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	$ 27,911	47%
	Year 1 Total	$ 72,765	$ 129,420	78%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 10,692	$ -	-100%
	Year 2 Total	$ 10,692	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 8,316	$ -	-100%
	Year 3 Total	$ 8,316	$ -	-100%
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**	**$129,420**	**28%**

Table 55: 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	19	19%	634	150	-76%	40	8	-80%	
Year 2	25	28	12%	991	507	-49%	40	18	-54%	
Year 3	32	35	9%	1,269	785	-38%	40	22	-43%	80%
Year 4	36	39	8%	1,428	944	-34%	40	24	-39%	
Year 5	40	43	8%	1,587	1,103	-31%	40	26	-35%	
Years 1-5 Total	**40**	**43**	**8%**	**5,909**	**3,487**	**-41%**	**40**	**26**	**-35%**	

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 56: 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	$ 10,283	-78%
	Year 1 Total	$ 135,556	$ 109,385	-19%
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	$ -	-100%
	Year 3 Total	$ 23,759	$ -	-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		**$194,953**	**$109,385**	**-44%**

Table 57: 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	7	-83%	3,370	63	-98%	84	9	-89%	
Year 2	70	37	-47%	5,898	2,591	-56%	84	70	-17%	
Year 3	90	57	-37%	7,583	4,276	-44%	84	75	-11%	0%
Year 4	90	57	-37%	7,583	4,276	-44%	84	75	-11%	
Year 5	90	57	-37%	7,583	4,276	-44%	84	75	-11%	
Years 1-5 Total	**90**	**57**	**-37%**	**32,017**	**15,480**	**-52%**	**84**	**75**	**-11%**	

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 58: 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	$ -	-100%
	Year 2 Total	$ 59,398	$ -	-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		**$255,521**	**$68,387**	**-73%**

Table 59: 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	2,419	-47%	46	48	5%	0%
Year 3	100	50	-50%	4,593	2,419	-47%	46	48	5%	
Year 4	100	50	-50%	4,593	2,419	-47%	46	48	5%	
Year 5	100	50	-50%	4,593	2,419	-47%	46	48	5%	
Years 1-5 Total	**100**	**50**	**-50%**	**20,546**	**9,676**	**-53%**	**46**	**48**	**5%**	

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 60: 2011 FEVI Top 5 – Veterans Memorial Parkway Costs

2011 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550002742	Veteran's Memorial Parkway	Original Forecast	Actual	Variance %
Year 1	Mains	$ 54,615	$ 68,023	25%
	Service lines and meters	$ 13,068	$ -	-100%
	Year 1 Total	$ 67,683	$ 68,023	1%
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	$ -	-100%
	Year 3 Total	$ 13,068	$ -	-100%
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**	**$68,023**	**-36%**

Table 61: 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	0	-100%	694	0	-100%	63			45%
Year 2	21	10	-52%	1,457	763	-48%	69	76	10%	
Year 3	32	21	-34%	1,964	1,270	-35%	61	60	-1%	
Year 4	43	32	-26%	2,471	1,777	-28%	57	56	-3%	
Year 5	44	33	-25%	2,536	1,842	-27%	58	56	-3%	
Years 1-5 Total	**44**	**33**	**-25%**	**9,122**	**5,652**	**-38%**	**58**	**56**	**-3%**	

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 62: 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	$ 20,566	24%
	Year 1 Total	$ 43,831	$ 76,138	74%
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	$ -	-100%
	Year 3 Total	$ 8,316	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	

Table 63: 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	14	0%	383	302	-21%	27	22	-21%	
Year 2	21	21	0%	575	494	-14%	27	24	-14%	
Year 3	28	28	0%	767	686	-11%	27	24	-11%	80%
Year 4	28	28	0%	767	686	-11%	27	24	-11%	
Year 5	28	28	0%	767	686	-11%	27	24	-11%	
Years 1-5 Total	**28**	**28**	**0%**	**3,259**	**2,854**	**-12%**	**27**	**24**	**-11%**	

Notes:

- Actual costs are higher due to a conflict with fire hydrants and a water main.

1 **Table 64: 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	0.36	-62%
Mountain Heights Rd	1.29	0.82	-36%
Sooke Road	1.45	2.09	44%
Veteran's Memorial Parkway	1.52	0.88	-42%
Latoria Road	0.87	0.44	-50%
Years 1-5 Total	**1.22**	**0.92**	**-25%**

2

3

8 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, 2011.
- 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 is used to indicate a forecast year.

8.1 2010 FEI Random Sample Results

The tables below summarize the sample aggregate 2010 main extension results for FEI.

Table 65: 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	$ 350,952	49%
	Year 1 Total	$ 693,121	$ 804,043	16%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 93,463	$ 188,734	102%
	Year 2 Total	$ 93,463	$ 188,734	102%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 51,627	$ -	-100%
	Year 3 Total	$ 51,627	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 25,814	$ -	-100%
	Year 4 Total	$ 25,814	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 19,583	$ -	-100%
	Year 5 Total	$ 19,583	$ -	-100%
Years 1-5 Total		**$883,607**	**$992,778**	**12%**

Table 66: 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	225	-15%	39,692	19,071	-52%	150	85	-44%
Year 2	369	346	-6%	50,019	29,288	-41%	136	85	-38%
Year 3	427	404	-5%	55,967	35,236	-37%	131	87	-33%
Year 4	456	433	-5%	58,932	38,201	-35%	129	88	-32%
Year 5	478	455	-5%	61,244	40,513	-34%	128	89	-31%
Years 1-5 Total	**478**	**455**	**-5%**	**265,854**	**162,308**	**-39%**	**128**	**89**	**-31%**

Table 67: 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	0.90	-47%
Years 1-5 Total	**1.69**	**0.90**	**-47%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[14].
- 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.

8.2 2010 FEVI Random Sample Results

The tables below summarize the sample aggregate 2010 main extension results for FEVI.

[14] Addendum to Main Extension Report and FortisBC Energy Inc. Vertical Subdivision Report for 2010 Year End, submitted to the Commission October 14, 2011.

Table 68: 2010 FEVI Aggregate Main Extensions Costs

2010 SAMPLE MAIN EXTENSIONS - COSTS				
FEVI	Cost of Installation ($)			
		Original Forecast	Actual	Variance %
Year 1	Mains	$ 467,152	$ 482,629	3%
	Service lines and meters	$ 267,481	$ 168,935	-37%
	Year 1 Total	$ 734,634	$ 651,564	-11%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 78,353	$ 117,520	50%
	Year 2 Total	$ 78,353	$ 117,520	50%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 9,006	$ -	-100%
	Year 3 Total	$ 9,006	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 7,205	$ -	-100%
	Year 4 Total	$ 7,205	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$829,198**	**$769,084**	**-7%**

Table 69: 2010 FEVI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2010 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	297	115	-61%	20,565	10,030	-51%	69	87	26%
Year 2	384	195	-49%	24,547	11,428	-53%	64	59	-8%
Year 3	394	205	-48%	24,899	11,780	-53%	63	57	-9%
Year 4	402	213	-47%	25,143	12,024	-52%	63	56	-10%
Year 5	402	213	-47%	25,143	12,024	-52%	63	56	-10%
Years 1-5 Total	**402**	**213**	**-47%**	**120,297**	**57,285**	**-52%**	**63**	**56**	**-10%**

Table 70: 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	0.93	-37%
Years 1-5 Total	**1.48**	**0.93**	**-37%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed to the Commission[15].
- 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.

8.3 2010 FEI Top 5 Results

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 71 & 72	Table 73 & 74	Table 75 & 76	Table 77 & 78	Table 79 & 80	Table 81
Whiskey Jack Drive	Gislason Avenue	Progress Way	Highway 95A	Pinot Noir Drive	Top 5 PI Results

15 Addendum to Main Extension Report and FortisBC Energy Inc. Vertical Subdivision Report for 2010 Year End, submitted to the Commission October 14, 2011.

Table 71: 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	$ 38,995	46%
	Year 1 Total	$ 137,132	$ 200,452	46%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 17,802	$ 20,277	14%
	Year 2 Total	$ 17,802	$ 20,277	14%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 4,451	$ -	-100%
	Year 3 Total	$ 4,451	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 4,451	$ -	-100%
	Year 4 Total	$ 4,451	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 4,451	$ -	-100%
	Year 5 Total	$ 4,451	$ -	-100%
Years 1-5 Total		**$168,286**	**$220,729**	**31%**

Table 72: 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	25	-17%	3,022	1,570	-48%	101	63	-38%	0%
Year 2	50	38	-24%	5,036	2,072	-59%	101	55	-46%	
Year 3	55	43	-22%	5,540	2,576	-54%	101	60	-41%	
Year 4	60	48	-20%	6,044	3,080	-49%	101	64	-36%	
Year 5	65	53	-18%	6,548	3,584	-45%	101	68	-33%	
Years 1-5 Total	**65**	**53**	**-18%**	**26,190**	**12,881**	**-51%**	**101**	**68**	**-33%**	

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 73: 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	$ 113,864	540%
	Year 1 Total	$ 162,418	$ 241,750	49%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 17,802	$ 1,560	-91%
	Year 2 Total	$ 17,802	$ 1,560	-91%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 17,802	$ -	-100%
	Year 3 Total	$ 17,802	$ -	-100%
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**	**$243,310**	**4%**

Table 74: 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	4,755	120%	108	65	-40%	0%
Year 2	40	74	85%	4,326	4,821	11%	108	65	-40%	
Year 3	60	94	57%	6,489	6,984	8%	108	74	-31%	
Year 4	80	114	43%	8,652	9,147	6%	108	80	-26%	
Year 5	100	134	34%	10,815	11,310	5%	108	84	-22%	
Years 1-5 Total	**100**	**134**	**34%**	**32,445**	**37,017**	**14%**	**108**	**84**	**-22%**	

Table 75: 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	$ 1,560	-42%
	Year 1 Total	$ 121,313	$ 82,595	-32%
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	$ -	-100%
	Year 4 Total	$ 890	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 3,560	$ -	-100%
	Year 5 Total	$ 3,560	$ -	-100%
Years 1-5 Total		**$140,005**	**$82,595**	**-41%**

Table 76: 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	1	-67%	1,912	200	-90%	637	200	-69%	
Year 2	15	1	-93%	4,629	200	-96%	309	200	-35%	
Year 3	19	5	-74%	7,178	2,749	-62%	378	550	46%	0%
Year 4	20	6	-70%	8,098	3,669	-55%	405	611	51%	
Year 5	24	10	-58%	11,543	7,114	-38%	481	711	48%	
Years 1-5 Total	**24**	**10**	**-58%**	**33,360**	**13,930**	**-58%**	**481**	**711**	**48%**	

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 77: 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	$ 1,560	-88%
	Year 1 Total	$ 76,402	$ 74,470	-3%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 8,901	$ 4,679	-47%
	Year 2 Total	$ 8,901	$ 4,679	-47%
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**	**$79,149**	**-23%**

Table 78: 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	227	-85%	101	227	125%	0%
Year 2	25	4	-84%	2,518	472	-81%	101	118	17%	
Year 3	35	14	-60%	3,525	1,479	-58%	101	106	5%	
Year 4	45	24	-47%	4,532	2,486	-45%	101	104	3%	
Year 5	45	24	-47%	4,532	2,486	-45%	101	104	3%	
Years 1-5 Total	**45**	**24**	**-47%**	**16,618**	**7,150**	**-57%**	**101**	**104**	**3%**	

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 79: 2010 FEI Top 5 – Pinot Noir Drive Costs

2010 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
4110027393	Pinot Noir Dr	Original Forecast	Actual	Variance %
Year 1	Mains	$ 84,220	$ 46,420	-45%
	Service lines and meters	$ -	$ 17,158	
	Year 1 Total	$ 84,220	$ 63,578	-25%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 21,363	$ 10,919	-49%
	Year 2 Total	$ 21,363	$ 10,919	-49%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 21,363	$ -	-100%
	Year 3 Total	$ 21,363	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 12,462	$ -	-100%
	Year 4 Total	$ 12,462	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$139,408**	**$74,496**	**-47%**

Table 80: 2010 FEI Top 5 – Pinot Noir 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			
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	11	-	0	830	-	0	75	-	
Year 2	24	18	-25%	2,417	1,669	-31%	101	93	-8%	
Year 3	48	42	-13%	4,834	4,086	-15%	101	97	-3%	0%
Year 4	62	56	-10%	6,244	5,496	-12%	101	98	-3%	
Year 5	62	56	-10%	6,244	5,496	-12%	101	98	-3%	
Years 1-5 Total	**62**	**56**	**-10%**	**19,739**	**17,577**	**-11%**	**101**	**98**	**-3%**	

Notes:

- The costs for this project have been reduced by a CIAC of approximately $18,000.

Table 81: 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	0.32	-59%
Gislason Avenue	0.96	0.86	-10%
Progress Way	1.05	1.38	32%
Highway 95A	0.93	0.46	-51%
Pinot Noir Dr	0.84	1.01	20%
Years 1-5 Total	**0.91**	**0.80**	**-12%**

8.1 2010 FEVI Top 5 Results

The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 82 & 83	Table 84 & 85	Table 86 & 87	Table 88 & 89	Table 90 & 91	Table 92
Riverstone Drive	Norton Road	Chilco Road	Fifth Street	Rosstown Road	Top 5 PI Results

Table 82: 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	$ 33,787	-17%
	Year 1 Total	$ 115,667	$ 142,310	23%
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		**$115,667**	**$142,310**	**23%**

Table 83: 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	23	-49%	3,150	617	-80%	70	27	-62%	0%
Year 2	45	23	-49%	3,150	617	-80%	70	27	-62%	
Year 3	45	23	-49%	3,150	617	-80%	70	27	-62%	
Year 4	45	23	-49%	3,150	617	-80%	70	27	-62%	
Year 5	45	23	-49%	3,150	617	-80%	70	27	-62%	
Years 1-5 Total	**45**	**23**	**-49%**	**15,750**	**3,086**	**-80%**	**70**	**27**	**-62%**	

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.

1 **Table 84: 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	$ 35,256	161%
	Year 1 Total	$ 60,855	$ 100,208	65%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 13,509	$ 4,407	-67%
	Year 2 Total	$ 13,509	$ 4,407	-67%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 13,509	$ -	-100%
	Year 3 Total	$ 13,509	$ -	-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		**$87,874**	**$104,615**	**19%**

2

3

4 **Table 85: 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	24	60%	1,050	526	-50%	70	22	-69%	0%
Year 2	30	27	-10%	2,100	661	-69%	70	24	-65%	
Year 3	45	42	-7%	3,150	1,711	-46%	70	41	-42%	
Year 4	45	42	-7%	3,150	1,711	-46%	70	41	-42%	
Year 5	45	42	-7%	3,150	1,711	-46%	70	41	-42%	
Years 1-5 Total	**45**	**42**	**-7%**	**12,600**	**6,320**	**-50%**	**70**	**41**	**-42%**	

5

6

Table 86: 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	$ -	-100%
	Year 1 Total	$ 100,387	$ 90,789	-10%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 19,813	$ 32,318	63%
	Year 2 Total	$ 19,813	$ 32,318	63%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 18,913	$ -	-100%
	Year 3 Total	$ 18,913	$ -	-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		**$139,113**	**$123,107**	**-12%**

Table 87: 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	0	-100%	1,060	0	-100%	48	0	-100%	
Year 2	44	22	-50%	2,017	287	-86%	46	13	-72%	
Year 3	65	43	-34%	2,878	1,148	-60%	44	27	-40%	0%
Year 4	65	43	-34%	2,878	1,148	-60%	44	27	-40%	
Year 5	65	43	-34%	2,878	1,148	-60%	44	27	-40%	
Years 1-5 Total	**65**	**43**	**-34%**	**11,711**	**3,731**	**-68%**	**44**	**27**	**-40%**	

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 88: 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	$ 38,633	138%
	Service lines and meters	$ 16,211	$ 29,380	81%
	Year 1 Total	$ 32,441	$ 68,013	110%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 1,469	
	Year 2 Total	$ -	$ 1,469	
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**	**$69,482**	**114%**

Table 89: 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	4,847	-51%	551	242	-56%	0%
Year 2	18	21	17%	9,914	6,421	-35%	551	306	-44%	
Year 3	18	21	17%	9,914	6,421	-35%	551	306	-44%	
Year 4	18	21	17%	9,914	6,421	-35%	551	306	-44%	
Year 5	18	21	17%	9,914	6,421	-35%	551	306	-44%	
Years 1-5 Total	**18**	**21**	**17%**	**49,570**	**30,532**	**-38%**	**551**	**306**	**-44%**	

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 90: 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	$ 1,469	-46%
	Year 1 Total	$ 22,166	$ 39,144	77%
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**	**$39,144**	**47%**

Table 91: 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	1	-67%	221	11	-95%	74	11	-85%	0%
Year 2	6	1	-83%	549	11	-98%	92	11	-88%	
Year 3	7	2	-71%	609	71	-88%	87	36	-59%	
Year 4	8	3	-63%	628	90	-86%	79	30	-62%	
Year 5	8	3	-63%	628	90	-86%	79	30	-62%	
Years 1-5 Total	**8**	**3**	**-63%**	**2,635**	**274**	**-90%**	**79**	**30**	**-62%**	

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.

Table 92: 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	0.15	-87%
Norton Road	1.38	0.57	-59%
Chilco Road	1.17	0.47	-60%
Fifth Street	17.38	7.05	-59%
Rosstown Road	0.81	0.00	-100%
Years 1-5 Total	**4.38**	**1.65**	**-62%**

9 2009 MAIN EXTENSIONS

The following section summarizes the attachment and consumption results for the 2009 main extensions including vertical subdivisions.

- The forecasted results contained in this section are based on projects for the 2009 gas year (November 01, 2008 to October 31, 2009).
- The actual results in this section are from November 01, 2008 to October 31, 2011.
- 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 2009 FEI Random Sample Results

The tables below summarize the sample aggregate 2009 main extension results for FEI.

Table 93: 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	$ 617,105	0%
	Year 1 Total	$ 1,490,308	$ 1,561,753	5%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 217,513	$ 397,389	83%
	Year 2 Total	$ 217,513	$ 397,389	83%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 174,805	$ 250,911	44%
	Year 3 Total	$ 174,805	$ 250,911	44%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 120,178	$ -	-100%
	Year 4 Total	$ 120,178	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 90,382	$ -	-100%
	Year 5 Total	$ 90,382	$ -	-100%
Years 1-5 Total		**$2,093,186**	**$2,210,053**	**6%**

Table 94: 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	455	-27%	75,052	33,360	-56%	121	73	-39%
Year 2	840	748	-11%	95,200	50,330	-47%	113	67	-41%
Year 3	1,016	933	-8%	111,478	59,046	-47%	110	63	-42%
Year 4	1,137	1,054	-7%	122,782	70,350	-43%	108	67	-38%
Year 5	1,228	1,145	-7%	131,524	79,092	-40%	107	69	-36%
Years 1-5 Total	**1,228**	**1,145**	**-7%**	**536,036**	**292,176**	**-45%**	**107**	**69**	**-36%**

Table 95: 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	0.79	-45%
Years 1-5 Total	**1.44**	**0.79**	**-45%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[16].
- 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.

9.2 2009 FEVI Random Sample Results

The tables below summarize the sample aggregate 2009 main extension results for FEVI.

[16] TGI & TGVI Main Extension Report and TGI and Revised Vertical Subdivision Report for 2009 Year End, submitted to the Commission August 18, 2010.

Table 96: 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	$ 257,108	-43%
	Year 1 Total	$ 1,244,286	$ 1,208,150	-3%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 47,922	$ 140,828	194%
	Year 2 Total	$ 47,922	$ 140,828	194%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 23,961	$ 65,892	175%
	Year 3 Total	$ 23,961	$ 65,892	175%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 18,550	$ -	-100%
	Year 4 Total	$ 18,550	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 1,546	$ -	-100%
	Year 5 Total	$ 1,546	$ -	-100%
Years 1-5 Total		**$1,336,265**	**$1,414,870**	**6%**

Table 97: 2009 FEVI 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		
FEVI	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %	Original Forecast	Actual or Re-Forecast	Variance %
Year 1	579	199	-66%	39,644	6,882	-83%	68	35	-49%
Year 2	641	308	-52%	43,890	9,146	-79%	68	30	-57%
Year 3	672	359	-47%	45,438	10,764	-76%	68	30	-56%
Year 4	696	383	-45%	46,403	11,729	-75%	67	31	-54%
Year 5	698	385	-45%	46,493	11,819	-75%	67	31	-54%
Years 1-5 Total	**698**	**385**	**-45%**	**221,868**	**50,340**	**-77%**	**67**	**31**	**-54%**

1 **Table 98: 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	0.30	-82%
Years 1-5 Total	**1.63**	**0.30**	**-82%**

2

3 Notes:

4 • The main extension cost variance has been reviewed in a previous report filed with the
5 Commission[17].

6 • The variance between years 1-3 forecast and year's 1-3 actual costs is attributable to a
7 combination of variance in costs and attachments.

8 • 5 FEVI customers made a contribution in aid of construction in order to reach the individual main
9 extension PI threshold of 0.8.

10 9.3 2009 FEI Top 5 Results

11 The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 99 & 100	Table 101 & 102	Table 103 & 104	Table 105 & 106	Table 107 & 108	Table 109
Tronson Road	2nd Avenue	Upper Hyde Creek	108 Avenue	University Way	Top 5 PI Results

[17] TGI & TGVI Main Extension Report and TGI and Revised Vertical Subdivision Report for 2009 Year End, submitted to the Commission August 18, 2010.

Table 99: 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	$ -	$ -	
	Year 1 Total	$ 337,574	$ 254,932	-24%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 49,660	$ 8,138	-84%
	Year 2 Total	$ 49,660	$ 8,138	-84%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 49,660	$ 6,781	-86%
	Year 3 Total	$ 49,660	$ 6,781	-86%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 49,660	$ -	-100%
	Year 4 Total	$ 49,660	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 54,627	$ -	-100%
	Year 5 Total	$ 54,627	$ -	-100%
Years 1-5 Total		**$541,182**	**$269,851**	**-50%**

Table 100: 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	0	0%	0	0	0%	0	0	0%	
Year 2	50	6	-88%	5,878	202	-97%	118	34	-71%	
Year 3	100	11	-89%	11,756	359	-97%	118	33	-72%	0%
Year 4	150	61	-59%	17,634	6,237	-65%	118	102	-13%	
Year 5	205	116	-43%	24,100	12,703	-47%	118	110	-7%	
Years 1-5 Total	**205**	**116**	**-43%**	**59,368**	**19,502**	**-67%**	**118**	**110**	**-7%**	

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 101: 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	$ 10,850	-77%
	Year 1 Total	$ 240,526	$ 191,257	-20%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 65,552	$ 109,858	68%
	Year 2 Total	$ 65,552	$ 109,858	68%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 78,464	$ 155,972	99%
	Year 3 Total	$ 78,464	$ 155,972	99%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 66,545	$ -	-100%
	Year 4 Total	$ 66,545	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 45,688	$ -	-100%
	Year 5 Total	$ 45,688	$ -	-100%
Years 1-5 Total		**$496,774**	**$457,087**	**-8%**

Table 102: 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	8	-83%	4,685	350	-93%	98	44	-55%	0%
Year 2	114	89	-22%	11,127	3,581	-68%	98	40	-59%	
Year 3	193	204	6%	18,837	8,360	-56%	98	41	-58%	
Year 4	260	271	4%	25,376	14,899	-41%	98	55	-44%	
Year 5	306	317	4%	29,733	19,256	-35%	97	61	-37%	
Years 1-5 Total	**306**	**317**	**4%**	**89,758**	**46,445**	**-48%**	**97**	**61**	**-37%**	

Table 103: 2009 FEI Top 5 – Upper Hyde Creek Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
4110025291	Upper Hyde Creek	Original Forecast	Actual	Variance %
Year 1	Mains	$ 61,300	$ 103,212	68%
	Service lines and meters	$ 114,219	$ 92,227	-19%
	Year 1 Total	$ 175,519	$ 195,439	11%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 46,113	
	Year 2 Total	$ -	$ 46,113	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 1,356	
	Year 3 Total	$ -	$ 1,356	
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**	**$242,908**	**38%**

Table 104: 2009 FEI Top 5 – Upper Hyde Creek Attachments, Consumption and Use per Customer

2009 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
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	4,610	-65%	114	68	-41%	0%
Year 2	115	102	-11%	13,161	7,280	-45%	114	71	-38%	
Year 3	115	103	-10%	13,161	7,330	-44%	114	71	-38%	
Year 4	115	103	-10%	13,161	7,330	-44%	114	71	-38%	
Year 5	115	103	-10%	13,161	7,330	-44%	114	71	-38%	
Years 1-5 Total	**115**	**103**	**-10%**	**65,805**	**33,879**	**-49%**	**114**	**71**	**-38%**	

Notes:

- Cost overruns associated with a bridge crossing have resulted in significant cost increases.

Table 105: 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	$ 54,251	264%
	Year 1 Total	$ 100,215	$ 151,523	51%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 14,898	$ 20,344	37%
	Year 2 Total	$ 14,898	$ 20,344	37%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 14,898	$ 35,263	137%
	Year 3 Total	$ 14,898	$ 35,263	137%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 14,898	$ -	-100%
	Year 4 Total	$ 14,898	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 17,878	$ -	-100%
	Year 5 Total	$ 17,878	$ -	-100%
Years 1-5 Total		**$162,787**	**$207,130**	**27%**

Table 106: 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	40	167%	1,638	2,122	30%	109	53	-51%	0%
Year 2	30	55	83%	3,319	2,925	-12%	111	53	-52%	
Year 3	45	81	80%	5,000	4,057	-19%	111	50	-55%	
Year 4	60	96	60%	6,681	5,738	-14%	111	60	-46%	
Year 5	78	114	46%	8,699	7,756	-11%	112	68	-39%	
Years 1-5 Total	**78**	**114**	**46%**	**25,337**	**22,598**	**-11%**	**112**	**68**	**-39%**	

Table 107: 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	$ -	$ 1,356	
	Year 1 Total	$ 182,972	$ 98,377	-46%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 993	$ 1,356	37%
	Year 2 Total	$ 993	$ 1,356	37%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 25,823	$ 1,356	-95%
	Year 3 Total	$ 25,823	$ 1,356	-95%
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	$ -	-100%
	Year 5 Total	$ 24,830	$ -	-100%
Years 1-5 Total		**$260,442**	**$101,089**	**-61%**

Table 108: 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	1	-	0	1,046	-	0	1,046	-	
Year 2	1	2	100%	1,750	1,046	-40%	1,750	523	-70%	
Year 3	27	3	-89%	4,913	1,067	-78%	182	356	95%	0%
Year 4	53	29	-45%	8,076	4,230	-48%	152	146	-4%	
Year 5	78	54	-31%	10,489	6,643	-37%	134	123	-9%	
Years 1-5 Total	**78**	**54**	**-31%**	**25,228**	**14,031**	**-44%**	**134**	**123**	**-9%**	

<u>Notes:</u>

- 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.

1 **Table 109: 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	0.50	-43%
2nd Avenue	1.25	0.77	-38%
Upper Hyde Creek	1.47	0.57	-61%
108 Avenue	1.02	0.70	-31%
University Way	0.85	0.66	-22%
Years 1-5 Total	**1.09**	**0.64**	**-41%**

2

3 ## 9.1 2009 FEVI Top 5 Results

4 The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 110 & 111	Table 112 & 113	Table 114 & 115	Table 116 & 117	Table 118 & 119	Table 120
Shawnigan Lake Road	West Coast Road	Wild Ridge Way	Hammond Bay Road	Kettle Creek Station	Top 5 PI Results

5

Table 110: 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	$ 49,096	-62%
	Year 1 Total	$ 822,978	$ 1,967,161	139%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 77,520	
	Year 2 Total	$ -	$ 77,520	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 21,642	$ 16,796	-22%
	Year 3 Total	$ 21,642	$ 16,796	-22%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$844,620**	**$2,061,477**	**144%**

Table 111: 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	38	-77%	14,000	6,828	-51%	85	180	112%	0%
Year 2	165	98	-41%	14,000	9,926	-29%	85	101	19%	
Year 3	193	111	-42%	20,315	10,203	-50%	105	92	-13%	
Year 4	193	111	-42%	20,315	10,203	-50%	105	92	-13%	
Year 5	193	111	-42%	20,315	10,203	-50%	105	92	-13%	
Years 1-5 Total	**193**	**111**	**-42%**	**88,945**	**47,363**	**-47%**	**105**	**92**	**-13%**	

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 112: 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	$ -	$ 1,292	
	Year 3 Total	$ -	$ 1,292	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 4 Total	$ -	$ -	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$417,059**	**$402,384**	**-4%**

Table 113: 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	19	-100%	70	19	-73%	**0%**
Year 4	201	1	-100%	14,070	19	-100%	70	19	-73%	
Year 5	201	1	-100%	14,070	19	-100%	70	19	-73%	
Years 1-5 Total	**201**	**1**	**-100%**	**70,350**	**58**	**-100%**	**70**	**19**	**-73%**	

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 114: 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	$ 41,344	-16%
	Year 1 Total	$ 116,623	$ 154,137	32%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 11,628	
	Year 2 Total	$ -	$ 11,628	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 3,876	
	Year 3 Total	$ -	$ 3,876	
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	$169,641	45%

Table 115: 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	32	-50%	4,480	1,207	-73%	70	38	-46%	0%
Year 2	64	41	-36%	4,480	1,523	-66%	70	37	-47%	
Year 3	64	44	-31%	4,480	1,700	-62%	70	39	-45%	
Year 4	64	44	-31%	4,480	1,700	-62%	70	39	-45%	
Year 5	64	44	-31%	4,480	1,700	-62%	70	39	-45%	
Years 1-5 Total	64	44	-31%	22,400	7,831	-65%	70	39	-45%	

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 116: 2009 FEVI Top 5 – Hammond Bay Road Costs

2009 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
4110001271	Hammond Bay Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 66,340	$ 79,513	20%
	Service lines and meters	$ 15,459	$ 6,460	-58%
	Year 1 Total	$ 81,799	$ 85,973	5%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 15,459	$ 11,628	-25%
	Year 2 Total	$ 15,459	$ 11,628	-25%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 15,459	$ 10,336	-33%
	Year 3 Total	$ 15,459	$ 10,336	-33%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 15,459	$ -	-100%
	Year 4 Total	$ 15,459	$ -	-100%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$128,175**	**$107,937**	**-16%**

Table 117: 2009 FEVI Top 5 – Hammond Bay 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			
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	5	-75%	1,400	183	-87%	70	37	-48%	0%
Year 2	40	14	-65%	2,800	337	-88%	70	24	-66%	
Year 3	60	22	-63%	3,531	510	-86%	59	23	-61%	
Year 4	80	42	-48%	4,262	1,241	-71%	53	30	-45%	
Year 5	80	42	-48%	4,262	1,241	-71%	53	30	-45%	
Years 1-5 Total	**80**	**42**	**-48%**	**16,255**	**3,511**	**-78%**	**53**	**30**	**-45%**	

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 118: 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	$ 11,628	-25%
	Year 1 Total	$ 72,636	$ 81,889	13%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 7,752	
	Year 2 Total	$ -	$ 7,752	
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**	**$89,641**	**-12%**

Table 119: 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	204	-88%	87	23	-74%	80%
Year 2	20	15	-25%	1,747	409	-77%	87	27	-69%	
Year 3	39	15	-62%	3,407	409	-88%	87	27	-69%	
Year 4	39	15	-62%	3,407	409	-88%	87	27	-69%	
Year 5	58	34	-41%	5,067	2,069	-59%	87	61	-30%	
Years 1-5 Total	**58**	**34**	**-41%**	**15,375**	**3,501**	**-77%**	**87**	**61**	**-30%**	

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 120: 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	0.20	-78%
West Coast Road	1.56	-0.11	-107%
Wild Ridge Way	1.91	0.33	-83%
Hammond Bay Road	1.18	0.38	-68%
Kettle Creek Station	1.73	0.64	-63%
Years 1-5 Total	**1.46**	**0.29**	**-80%**

2

3

10 2008 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, 2011.
- The tables included in this section contain a comparison of forecasted and actual costs, attachments and consumption for Year 4.
- 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.

10.1 2008 FEI Random Sample Results

The tables below summarize the sample aggregate 2008 main extension results for FEI.

Table 121: 2008 FEI Aggregate Main Extensions Costs

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	$ 248,642	-47%
	Year 1 Total	$ 818,039	$ 686,462	-16%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 24,576	$ 112,620	358%
	Year 2 Total	$ 24,576	$ 112,620	358%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 23,631	$ 143,335	507%
	Year 3 Total	$ 23,631	$ 143,335	507%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 13,233	$ 86,294	552%
	Year 4 Total	$ 13,233	$ 86,294	552%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 12,288	$ -	-100%
	Year 5 Total	$ 12,288	$ -	-100%
Years 1-5 Total		**$891,766**	**$1,028,711**	**15%**

Table 122: 2008 FEI Aggregate Main Extensions Attachments, Consumption and Use per Customer

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	13,883	-76%	117	82	-30%
Year 2	519	247	-52%	60,148	20,231	-66%	116	82	-29%
Year 3	544	345	-37%	62,557	26,963	-57%	115	78	-32%
Year 4	558	404	-28%	63,905	30,613	-52%	115	76	-34%
Year 5	571	417	-27%	65,148	31,856	-51%	114	76	-33%
Years 1-5 Total	**571**	**417**	**-27%**	**309,398**	**123,546**	**-60%**	**114**	**76**	**-33%**

Table 123: 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	0.75	-54%
Years 1-5 Total	**1.60**	**0.75**	**-54%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[18].
- The variance between years 1-4 forecast and year's 1-4 actual costs is attributable to a combination of variance in costs and attachments.
- Four FEI customers made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

10.2 2008 FEVI Random Sample Results

The tables below summarize the sample aggregate 2008 main extension results for FEVI.

[18] TGI & TGVI Main Extension Report and TGI and Revised Vertical Subdivision Report for 2008 Year End, submitted to the Commission April 3, 2009.

Table 124: 2008 FEVI Aggregate Main Extensions Costs

2008 SAMPLE MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
		Original Forecast	Actual	Variance %
Year 1	Mains	$264,194	$298,877	13%
	Service lines and meters	$244,921	$155,944	-36%
	Year 1 Total	$509,114	$454,821	-11%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$30,856	$64,848	110%
	Year 2 Total	$30,856	$64,848	110%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$1,929	$121,976	6225%
	Year 3 Total	$1,929	$121,976	6225%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$49,408	
	Year 4 Total	$ -	$49,408	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$4,821	$ -	-100%
	Year 5 Total	$4,821	$ -	-100%
Years 1-5 Total		**$546,720**	**$691,053**	**26%**

Table 125: 2008 FEVI Aggregate Main Extensions Attachments, Consumption and Use per Customer

2008 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	254	101	-60%	12,561	4,712	-62%	49	47	-6%
Year 2	286	143	-50%	14,482	5,972	-59%	51	42	-18%
Year 3	288	222	-23%	14,589	7,730	-47%	51	35	-31%
Year 4	288	254	-12%	14,589	8,743	-40%	51	34	-32%
Year 5	293	259	-12%	14,839	8,993	-39%	51	35	-31%
Years 1-5 Total	**293**	**259**	**-12%**	**71,060**	**36,151**	**-49%**	**51**	**35**	**-31%**

Table 126: 2008 FEVI Aggregate Main Extensions Profitability Index

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	0.71	-45%
Years 1-5 Total	**1.30**	**0.71**	**-45%**

Notes:

- The main extension cost variance has been reviewed in a previous report filed with the Commission[19].
- The variance between years 1-4 forecast and year's 1-4 actual costs is attributable to a combination of variance in costs and attachments.
- Four FEVI customers made a contribution in aid of construction in order to reach the individual main extension PI threshold of 0.8.

10.3 2008 FEI Top 5 Results

The top 5 main extensions with the highest cost for FEI are provided as follows:

Table 127 & 128	Table 129 & 130	Table 131 & 132	Table 133 & 134	Table 135 &136	Table 137
Trans-Canada Highway	Juniper Road	Crystal Creek Drive	61A Avenue	Rio Drive	Top 5 PI Results

[19] TGI & TGVI Main Extension Report and TGI and Revised Vertical Subdivision Report for 2008 Year End, submitted to the Commission April 3, 2009.

Table 127: 2008 FEI Top 5 –Trans-Canada Highway Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550000560	Trans-Canada Hwy	Original Forecast	Actual	Variance %
Year 1	Mains	$ 950,140	$ 838,718	-12%
	Service lines and meters	$ 128,550	$ 77,518	-40%
	Year 1 Total	$ 1,078,689	$ 916,236	-15%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 136,112	$ 52,654	-61%
	Year 2 Total	$ 136,112	$ 52,654	-61%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 103,029	$ 20,476	-80%
	Year 3 Total	$ 103,029	$ 20,476	-80%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 114,372	$ 2,925	-97%
	Year 4 Total	$ 114,372	$ 2,925	-97%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 945	$ -	-100%
	Year 5 Total	$ 945	$ -	-100%
Years 1-5 Total		$1,433,147	$992,291	-31%

Table 128: 2008 FEI Top 5 – Trans-Canada Highway Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Trans-Canada Hwy 5550000560	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	136	53	-61%	24,473	1,191	-95%	180	22	-88%	0%
Year 2	280	89	-68%	41,906	4,394	-90%	150	49	-67%	
Year 3	389	103	-74%	59,399	5,355	-91%	153	52	-66%	
Year 4	510	105	-79%	74,587	5,434	-93%	146	52	-65%	
Year 5	511	106	-79%	79,801	10,648	-87%	156	100	-36%	
Years 1-5 Total	511	106	-79%	280,166	27,022	-90%	156	100	-36%	

Notes:

- The mains were installed after all lots were registered and roads and other utilities were in place. Market conditions deteriorated shortly afterward and development of the property did not occur as anticipated. The property is currently in foreclosure.
- The load and customer attachment assumptions, while not achieved, may still materialize as the lots remain undeveloped but are being marketed.
- Twenty-two additional homes have recently been completed and have yet to be sold.
- The project costs have been reduced by a CIAC of approximately $89,000.

Table 129: 2008 FEI Top 5 – Juniper Road Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
4110009212	Juniper Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 24,141	$ 121,522	403%
	Service lines and meters	$ 9,452	$ -	-100%
	Year 1 Total	$ 33,593	$ 121,522	262%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 9,452	$ -	-100%
	Year 2 Total	$ 9,452	$ -	-100%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 10,397	$ -	-100%
	Year 3 Total	$ 10,397	$ -	-100%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ 6,617	$ 5,850	-12%
	Year 4 Total	$ 6,617	$ 5,850	-12%
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ 5,671	$ -	-100%
	Year 5 Total	$ 5,671	$ -	-100%
Years 1-5 Total		**$65,731**	**$127,372**	**94%**

Table 130: 2008 FEI Top 5 – Juniper Road Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Juniper Road 4110009212	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	10	0	-100%	1,250	0	-100%	125	0	-100%	0%
Year 2	20	0	-100%	2,500	0	-100%	125	0	-100%	
Year 3	31	0	-100%	3,875	0	-100%	125	0	-100%	
Year 4	38	4	-89%	4,750	162	-97%	125	40	-68%	
Year 5	44	10	-77%	5,500	912	-83%	125	91	-27%	
Years 1-5 Total	**44**	**10**	**-77%**	**17,875**	**1,074**	**-94%**	**125**	**91**	**-27%**	

Notes:

- Significant costs were incurred on this project related to soil compaction and road base repair.
- All lots for this project are fully serviced by the main. Twenty-four lots have been purchased but homes have yet to be constructed. The project has been delayed due to the recession but is now beginning to recover.
- The developer is currently engaged in attracting investors.

Table 131: 2008 FEI Top 5 – Crystal Creek Drive Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550001699	Crystal Creek Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 30,876	$ 116,239	276%
	Service lines and meters	$ 20,795	$ 2,925	-86%
	Year 1 Total	$ 51,671	$ 119,165	131%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 7,313	
	Year 2 Total	$ -	$ 7,313	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 2,925	
	Year 3 Total	$ -	$ 2,925	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 7,313	
	Year 4 Total	$ -	$ 7,313	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$51,671	$136,716	165%

Table 132: 2008 FEI Top 5 – Crystal Creek Drive Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Crystal Creek Drive 5550001699	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	2	-91%	3,070	284	-91%	140	142	2%	0%
Year 2	22	7	-68%	3,070	725	-76%	140	104	-26%	
Year 3	22	9	-59%	3,070	881	-71%	140	98	-30%	
Year 4	22	14	-36%	3,070	1,630	-47%	140	116	-17%	
Year 5	22	14	-36%	3,070	1,630	-47%	140	116	-17%	
Years 1-5 Total	**22**	**14**	**-36%**	**15,350**	**5,150**	**-66%**	**140**	**116**	**-17%**	

Notes:

- A very rocky ground surface added to the time it took to install the main. As a result, costs increased significantly. Also, the developer had already previously paved some of running line for the main which had to be repaired once the install was complete.
- Market downturn occurred after gas main installation which slowed housing starts. Potential to realize attachment and load assumptions still exists as lots remain undeveloped and are being marketed.

Table 133: 2008 FEI Top 5 – 61A Avenue Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550000251	61A Avenue	Original Forecast	Actual	Variance %
Year 1	Mains	$ 77,032	$ 114,145	48%
	Service lines and meters	$ 47,261	$ 40,953	-13%
	Year 1 Total	$ 124,293	$ 155,098	25%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 56,713	$ 61,429	8%
	Year 2 Total	$ 56,713	$ 61,429	8%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 57,658	$ 86,294	50%
	Year 3 Total	$ 57,658	$ 86,294	50%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 29,252	
	Year 4 Total	$ -	$ 29,252	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$238,665	$332,073	39%

Table 134: 2008 FEI Top 5 – 61A Avenue Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
61A Avenue 5550000251	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	28	-44%	4,827	2,018	-58%	97	72	-25%	0%
Year 2	110	70	-36%	10,619	5,264	-50%	97	75	-22%	
Year 3	171	129	-25%	16,507	9,419	-43%	97	73	-24%	
Year 4	171	149	-13%	16,507	10,822	-34%	97	73	-25%	
Year 5	171	149	-13%	16,507	10,822	-34%	97	73	-25%	
Years 1-5 Total	**171**	**149**	**-13%**	**64,967**	**38,344**	**-41%**	**97**	**73**	**-25%**	

Notes:

- The unanticipated depth of dig, conflicts with foreign utilities and unforeseen paving costs are all factors that drove up the cost of this job.

Table 135: 2008 FEI Top 5 – Rio Drive Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEI		Cost of Installation ($)		
5550001989	Rio Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 90,674	$ 85,549	-6%
	Service lines and meters	$ 37,809	$ -	-100%
	Year 1 Total	$ 128,482	$ 85,549	-33%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 37,809	$ 2,925	-92%
	Year 2 Total	$ 37,809	$ 2,925	-92%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ 11,343	$ 20,476	81%
	Year 3 Total	$ 11,343	$ 20,476	81%
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 16,089	
	Year 4 Total	$ -	$ 16,089	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$177,634**	**$125,040**	**-30%**

Table 136: 2008 FEI Top 5 – Rio Drive Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEI	Attachments			Consumption (GJ)			Use per Customer			
Rio Drive 5550001989	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	0	-100%	2,438	0	-100%	61	0	-100%	
Year 2	80	2	-98%	4,876	31	-99%	61	16	-74%	
Year 3	92	16	-83%	5,547	524	-91%	60	33	-46%	0%
Year 4	92	27	-71%	5,547	895	-84%	60	33	-45%	
Year 5	92	27	-71%	5,547	895	-84%	60	33	-45%	
Years 1-5 Total	**92**	**27**	**-71%**	**23,955**	**2,346**	**-90%**	**60**	**33**	**-45%**	

Notes:

- This project is a multi-phased project which was severely impacted by the economic downturn.
- The owner is actively engaged in marketing the development and the project is making a slow recovery.
- The project costs have been reduced by a CIAC of approximately $27,000.

Table 137: 2008 FEI Top 5 Main Extensions Profitability Index

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	0.08	-92%
Juniper Road	1.70	0.01	-99%
Crystal Creek Drive	1.00	0.15	-85%
61A Avenue	1.38	0.68	-51%
Rio Drive	1.00	0.08	-92%
Years 1-5 Average	**1.22**	**0.20**	**-84%**

10.1 2008 FEVI Top 5 Results

The top 5 main extensions with the highest cost for FEVI are provided as follows:

Table 138 & 139	Table 140 & 141	Table 142 & 143	Table 144 & 145	Table 146 &147	Table 148
Players Drive	French Road	Hutchinson Road	Sewell Road	Phillips Road	Top 5 PI Results

Table 138: 2008 FEVI Top 5 – Players Drive Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550000862	Players Drive	Original Forecast	Actual	Variance %
Year 1	Mains	$ 237,392	$ 219,182	-8%
	Service lines and meters	$ 71,355	$ -	-100%
	Year 1 Total	$ 308,746	$ 219,182	-29%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 1,544	
	Year 2 Total	$ -	$ 1,544	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 77,200	
	Year 3 Total	$ -	$ 77,200	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 29,336	
	Year 4 Total	$ -	$ 29,336	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$308,746**	**$327,262**	**6%**

Table 139: 2008 FEVI Top 5 – Players Drive Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Players Drive 5550000862	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	74	0	-100%	13,307	0	-100%	180	0	-100%	0%
Year 2	74	1	-99%	13,307	32	-100%	180	32	-82%	
Year 3	74	51	-31%	13,307	1,994	-85%	180	39	-78%	
Year 4	74	70	-5%	13,307	2,927	-78%	180	42	-77%	
Year 5	74	70	-5%	13,307	2,927	-78%	180	42	-77%	
Years 1-5 Total	**74**	**70**	**-5%**	**66,535**	**7,879**	**-88%**	**180**	**42**	**-77%**	

Notes:

- This development is a multi-phased project which was severely impacted by the economic downturn but has since recovered.

Table 140: 2008 FEVI Top 5 – French Road Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
4110025230	French Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 68,993	$ 159,929	132%
	Service lines and meters	$ 48,213	$ 13,896	-71%
	Year 1 Total	$ 117,205	$ 173,825	48%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 15,440	
	Year 2 Total	$ -	$ 15,440	
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 24,704	
	Year 3 Total	$ -	$ 24,704	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 13,896	
	Year 4 Total	$ -	$ 13,896	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		**$117,205**	**$227,865**	**94%**

Table 141: 2008 FEVI Top 5 – French Road Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
French Road 4110025230	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	9	-82%	3,500	346	-90%	70	38	-45%	0%
Year 2	50	19	-62%	3,500	594	-83%	70	31	-55%	
Year 3	50	35	-30%	3,500	1,043	-70%	70	30	-57%	
Year 4	50	44	-12%	3,500	1,271	-64%	70	29	-59%	
Year 5	50	44	-12%	3,500	1,271	-64%	70	29	-59%	
Years 1-5 Total	**50**	**44**	**-12%**	**17,500**	**4,524**	**-74%**	**70**	**29**	**-59%**	

Notes:

- Unforeseen rock, asphalt removal and restoration of roads required large quantities materials and resources resulting in increased costs.
- Additional staking due to revised development plans also contributed to cost overruns.

Table 142: 2008 FEVI Top 5 – Hutchinson Road Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
4110016828	Hutchinson Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 81,857	$ 86,812	6%
	Service lines and meters	$ 39,534	$ 10,808	-73%
	Year 1 Total	$ 121,392	$ 97,620	-20%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 32,785	$ 41,688	27%
	Year 2 Total	$ 32,785	$ 41,688	27%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 43,232	
	Year 3 Total	$ -	$ 43,232	
Year 4	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 3,088	
	Year 4 Total	$ -	$ 3,088	
Year 5	Mains	$ -	$ -	
	Service lines and meters	$ -	$ -	
	Year 5 Total	$ -	$ -	
Years 1-5 Total		$154,176	$185,628	20%

Table 143: 2008 FEVI Top 5 – Hutchinson Road Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Hutchinson Road 4110016828	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	41	7	-83%	2,255	172	-92%	55	25	-55%	0%
Year 2	75	34	-55%	4,125	870	-79%	55	26	-53%	
Year 3	75	62	-17%	4,125	1,526	-63%	55	25	-55%	
Year 4	75	64	-15%	4,125	1,551	-62%	55	24	-56%	
Year 5	75	64	-15%	4,125	1,551	-62%	55	24	-56%	
Years 1-5 Total	**75**	**64**	**-15%**	**18,755**	**5,670**	**-70%**	**55**	**24**	**-56%**	

Notes:

- This subdivision was developed for the lots to be sold directly to individual builders and was ready for building right at the time of the economic downturn. It is making a slow recovery.

Table 144: 2008 FEVI Top 5 – Sewell Road Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
4110008114	Sewell Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 45,187	$ 21,412	-53%
	Service lines and meters	$ 9,643	$ 26,248	172%
	Year 1 Total	$ 54,830	$ 47,660	-13%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 14,464	$ 3,088	-79%
	Year 2 Total	$ 14,464	$ 3,088	-79%
Year 3	Mains	$ -	$ -	
	Service lines and meters	$ -	$ 16,984	
	Year 3 Total	$ -	$ 16,984	
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		**$69,293**	**$69,276**	**0%**

Table 145: 2008 FEVI Top 5 – Sewell Road Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Sewell Road 4110008114	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	10	17	70%	1,100	679	-38%	110	40	-64%	0%
Year 2	25	19	-24%	2,750	824	-70%	110	43	-61%	
Year 3	25	30	20%	2,750	1,110	-60%	110	37	-66%	
Year 4	25	31	24%	2,750	1,121	-59%	110	36	-67%	
Year 5	25	31	24%	2,750	1,121	-59%	110	36	-67%	
Years 1-5 Total	**25**	**31**	**24%**	**12,100**	**4,855**	**-60%**	**110**	**36**	**-67%**	

<u>Notes:</u>

- The existing utility ROW for this project was unable to accommodate the main. As a result construction took place in the existing roadway. Significant costs were incurred for both digging and road restoration.
- The project costs have been reduced by a CIAC of approximately $6,000.

Table 146: 2008 FEVI Top 5 – Phillips Road Costs

2008 TOP 5 MAIN EXTENSIONS - COSTS				
FEVI		Cost of Installation ($)		
5550000935	Phillips Road	Original Forecast	Actual	Variance %
Year 1	Mains	$ 196,787	$ 75,286	-62%
	Service lines and meters	$ 82,926	$ -	-100%
	Year 1 Total	$ 279,713	$ 75,286	-73%
Year 2	Mains	$ -	$ -	
	Service lines and meters	$ 964	$ 1,544	60%
	Year 2 Total	$ 964	$ 1,544	60%
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		**$280,677**	**$76,830**	**-73%**

Table 147: 2008 FEVI Top 5 – Phillips Road Attachments, Consumption and Use per Customer

2008 TOP 5 MAIN EXTENSIONS - ATTACHMENTS, CONSUMPTION, and USE PER CUSTOMER										
FEVI	Attachments			Consumption (GJ)			Use per Customer			
Phillips Road 5550000935	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	86	0	-100%	4,620	0	-100%	54	0	-100%	0%
Year 2	87	1	-99%	4,670	35	-99%	54	35	-35%	
Year 3	87	1	-99%	4,670	35	-99%	54	35	-35%	
Year 4	87	1	-99%	4,670	35	-99%	54	35	-35%	
Year 5	87	1	-99%	4,670	35	-99%	54	35	-35%	
Years 1-5 Total	**87**	**1**	**-99%**	**23,300**	**139**	**-99%**	**54**	**35**	**-35%**	

Notes:

- This project is a large phased subdivision which has been severely impacted by the economic downturn.
- Only 50 percent of the main has been completed, with no anticipation of full completion as it is currently on hold by the developer. Many of the lots still have no construction activity.

1 **Table 148: 2008 FEVI Top 5 Main Extensions Profitability Index**

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	0.26	-83%
French Road	1.22	0.16	-87%
Hutchinson Road	1.40	0.47	-66%
Sewell Road	1.03	0.51	-51%
Phillips Road	0.88	-0.08	-109%
Years 1-5 Average	**1.22**	**0.26**	**-78%**

2

3

11 CONCLUSION AND NEXT STEPS

For the 2012 MX Report, the Companies believe they are in full compliance with the Commission's Decision and Order No. G-152-07, and Order No. G-6-08. This Report also addresses the requests of Commission Staff and the related additional items identified in Letters No. L-67-11, L-19-12 and L-60-12.

The Companies have identified an area of concern within the MX Test methodology, specifically on the forecasting of individual customers' consumption levels. The current practice of forecasting new consumption values that are based on the historic usage of all existing current customers is not reflective of the behaviors of new customers and the challenges they face when connecting to Companies' systems.

Going forward, the Companies will continue to apply the format and methodologies used in the 2012 MX Report to future year end compliance reports as the Companies have directly applied the suggestions of Commission Staff and believe the reporting changes will ensure more meaningful and useful information on main extensions.

Appendix A

FEI TARIFF 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:

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. C
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.
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, 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 (i) any commission that is a successor to such commission, and (ii) 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. C/N
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 (i) 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*), (ii) relating to the revenues received by FortisBC Energy for Gas consumed within the municipality or First Nations lands (formerly, reserves within the *Indian Act*), and (iii) 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) and 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. C/N
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.
Midstream Cost Recovery Charge	Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.
Month	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. C
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.	C
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.	
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.	C
10^3m^3	Means 1,000 cubic metres.	

Appendix B

FEI TARIFF 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 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 the Company'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

EES CONSULTING
MAIN EXTENSION REPORT

FortisBC Energy Utilities
Review of System Extension Policies

March 2013

Prepared by:

EES Consulting

570 Kirkland Way, Suite 100
Kirkland, Washington 98033

A registered professional engineering corporation with offices in
Kirkland, WA and Portland, OR

Telephone: (425) 889-2700 Facsimile: (425) 889-2725

EES Consulting

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

570 Kirkland Way, Suite 100
Kirkland, Washington 98033

Telephone: 425 889-2700 Facsimile: 425 889-2725

A registered professional engineering corporation with offices in
Kirkland, WA and Portland, OR

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.

Attachment 20.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 23.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 23.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 24.4

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)