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September 17, 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) (collectively FEVI-FEW) Response to the BCUC Information Request (IR) No. 2

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. 2.

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

28.0 Reference: Exhibit B1-76, BCUC IR 1.2.1 - 1.2.2

Revenue Stabilization Deferral Account (RSDA) and Rate Impact – FEVI

FEVI-FEW response to BCUC IR 1.2.1 states:

> "… 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." [Emphasis added]

28.1 Please clarify why a revenue requirement decrease or a notional decrease in the delivery rate will end up reducing the RSDA balance. Wouldn't a delivery rate decrease, holding all else equal, end up building a RSDA balance when customer rates are frozen?

Response:

Yes, a revenue requirement (cost of service) decrease when customer rates are frozen would, all else equal, result in a higher RSDA balance to be returned to customers in the future. However, the original statement in the responses to BCUC FEVI-FEW IRs 1.2.1 and 1.2.2 was meant to reflect that there would be a reduction in the 2013 forecasted deficiency captured in the RSDA as shown in the approved financial schedules in Order G-44-12.

In reference to the second part of the question, given the rate freeze, a delivery rate decrease is not a plausible scenario. However, assuming the delivery rate was to decrease proportionately to the decrease in revenue requirement, holding all else equal, the current RSDA balance would remain unchanged as the decrease in revenue requirement would be recovered from customers through the change to the delivery rate. Conversely, a delivery rate decrease with no change to the revenue requirement would result in a deficiency and reduce the RSDA balance.

28.2 Assuming the rate freeze continues, will the opposite be true that a notional increase in the delivery rate will build a RSDA balance? Please explain or demonstrate.

Response:

No, an increase to the revenue requirement would result in a decrease to the remaining RSDA balance to be returned to customers. Please refer to the response to BCUC FEVI-FEW IR 2.28.1.

29.0 Reference: Exhibit B1-76, BCUC IR 1.4.1, Table 2

Business Profiles of FEI, FEVI and FEW 2009-2012

29.1 The "Rate Base" figures for each year 2009 to 2012 in the table suggest that the average annual growth rates in Rate Base are 3.0 percent for FEI, 13.5 percent for FEVI and 9.2 percent for FEW. Do FEVI/FEW agree? If not, please provide new calculations for the average annual growth.

Response:

The FEU calculate the FEI average annual growth in rate base as 3.0 percent from 2009 to 2012, the FEVI average annual growth in rate base as 13.5 percent from 2009 to 2012, and the FEW average annual growth in rate base as 9.8 percent from 2009 to 2012.

Regardless, customer growth rates in Table 2 were determined using changes in the annual number of customers serviced by each utility and changes in rate base can be the result of many variables and are subject to timing. For example, the large increases in FEVI rate base from 2010 to 2012 were mainly the result of the Mount Hayes LNG Facility capital costs while the large increase in FEW rate base in 2010 was mainly due to the Whistler Pipeline project, both the result of timing of large projects undertaken by the respective utilities and not representative of the average capital requirement of these utilities on an annual basis. Therefore, the timing of these expenditures and their inclusion in rate base is not indicative of customer growth trends over that same time period.

29.1.1 Please comment on the reasons for the high growth rates in the respective rate bases for FEVI and FEW relative to FEI.

Response:

Please refer to the response to BCUC FEVI-FEW IR 2.29.1.

29.2 With regard to FEVI's Energy information, please clarify whether it should read "35,449", "36,557", and "37,244" for the period 2009 through 2011, respectively. Please calculate the respective average annual growth rates for energy demand (2009-2012) for FEI, FEVI and FEW.

Response:

The 2009, 2010 and 2011 FEVI values were erroneously shown in GJs. The original table follows:

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

The corrected table follows:

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

Note that the correct 2011 value in TJs is 37,224 and not 37,244 as suggested in the question.

The annual growth rates and averages are shown below:

Annual Growth Rate, Energy (TJs)	2010	2011	2012	Average
FEI	1.6%	3.9%	2.2%	2.6%
FEVI	3.1%	1.8%	2.3%	2.4%
FEW	21.0%	-5.8%	-4.9%	3.5%

30.0 Reference: Exhibit B1-76, BCUC IR 1.4.2; Exhibit B1-77, BCPSO IR 1.14.1, Attachment 24.1

Use per Customer – FEVI

FEVI-FEW response to BCUC IR 1.4.2 provides that:

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

FEVI-FEW response to BSPCO IR 1.14.1 provides graphs and tables that compare FEVI and FEW's rates with BC Hydro's rates from 2009 to the present. FEVI and FEW have used the typical annual use rates for comparison purposes. In the graphs and tables, FEVI assumes a natural gas use of 59 GJ and FEW assumes a natural gas use of 90GJ.

Attachment 24.1 also provides the use per customer and net customer additions for FEI, FEVI, and FEW for the period 2001 through 2012.

30.1 For FEVI's graph and table in BCPSO IR 1.14.1, is natural gas assumption of 59 GJ reasonable given the information provided in FEVI's response to BCUC IR 1.4.2?

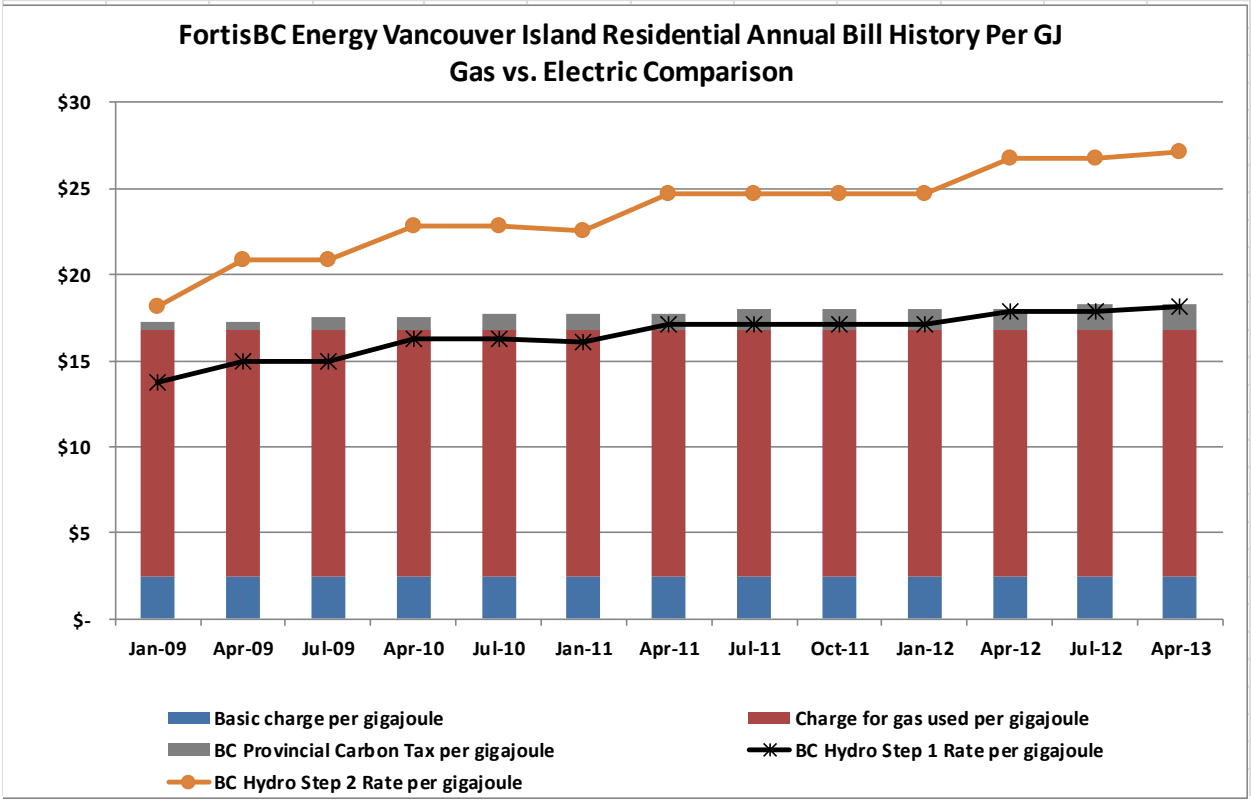
Response:

The use rate of 58.6 GJ was incorrectly used in the analysis for the graph and table in the response to BCPSO FEVI-FEW IR 1.14.1. It is the forecasted use rate which was used in Appendix J-3, Tab 1.2, page 1 of the FEI Amalco Bill Impact Schedules of the FortisBC Energy Utilities Common Rates, Amalgamation and Rate Design Application in 2012. This use rate should have been updated with the 2012 actual Use Per Customer of 49.5 GJ or a current forecasted use rate. Please refer to the response to BCUC FEVI-FEW IR 2.30.2 for an updated analysis.

30.2 Please provide another FEVI comparison with BC Hydro's rates using an assumption that is reflective of recent year's experience, say 52 GJ which is the average of 2009-2012.

Response:

Please refer to the graph and table below that compare FEVI rates with BC Hydro's rates from 2009 to present, with the annual use updated to 51.8 GJ, the average of FEVI's residential use per customer (UPC) from 2009 to 2012. Please refer to the response to BCUC FEVI-FEW IR 2.30.1 for additional information.



Assumptions:

Natural gas use of 52 GJ

Efficiency of gas equipment is 90% relative to 100% for electricity

FEVI amount includes the basic charge

BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use

	Date												
	Jan-09	**Apr-09**	**Jul-09**	**Apr-10**	**Jul-10**	**Jan-11**	**Apr-11**	**Jul-11**	**Oct-11**	**Jan-12**	**Apr-12**	**Jul-12**	**Apr-13**
FEVI Charges per Gigajoule													
Basic charge	$ 2.432	$ 2.432	$ 2.432	$ 2.432	$ 2.432	$ 2.432	$ 2.432	$ 2.432	$ 2.432	$ 2.433	$ 2.433	$ 2.433	$ 2.433
Charge for gas used	$ 14.325	$ 14.325	$ 14.325	$ 14.325	$ 14.325	$ 14.325	$ 14.325	$ 14.325	$ 14.325	$ 14.325	$ 14.325	$ 14.325	$ 14.325
BC Provincial Carbon Tax	$ 0.4966	$ 0.4966	$ 0.7449	$ 0.7449	$ 0.9932	$ 0.9932	$ 0.9932	$ 1.2415	$ 1.2415	$ 1.2415	$ 1.2415	$ 1.4898	$ 1.4898
Total charges	$ 17.254	$ 17.254	$ 17.502	$ 17.502	$ 17.751	$ 17.751	$ 17.751	$ 17.999	$ 17.999	$ 17.999	$ 17.999	$ 18.247	$ 18.247
FEVI Charges per Gigajoule													
BC Hydro Step 1 Rate	$ 13.725	$ 14.925	$ 14.925	$ 16.300	$ 16.300	$ 16.075	$ 17.100	$ 17.100	$ 17.100	$ 17.100	$ 17.850	$ 17.850	$ 18.125
BC Hydro Step 2 Rate	$ 18.125	$ 20.875	$ 20.875	$ 22.825	$ 22.825	$ 22.500	$ 24.650	$ 24.650	$ 24.650	$ 24.650	$ 26.750	$ 26.750	$ 27.150

Natural gas use of 52 GJ

Efficiency of gas equipment is 90% relative to 100% for electricity

1 BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use

2

31.0 Reference: Exhibit B1-76, BCUC IR 1.5.1

Main Extension Forecasting

FEVI-FEW response to BCUC IR 1.5.1 states that the variances between forecast and actual consumption values and the results contained in the annual Main Extension Report submissions should only be considered to be preliminary in nature.

Further, the response states that "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.

Attachment 5.1 contains the FEI-FEVI Main Extension Report for the 2012 Year End. By way of example, the following table shows three years of actual values with its original and adjusted forecasts:

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%	
Year 2	20	15	-25%	1,747	409	-77%	87	27	-69%	
Year 3	39	15	-62%	3,407	409	-88%	87	27	-69%	80%
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%**	

31.1 With regard to business risk, who is ultimately accountable for the favourable or unfavourable variance between forecast and actual values (i.e., the developer or the utility)? Please explain.

Response:

With respect to the main extension forecasting that is the subject of this information request, FEVI does not agree with the premise that a single party is 'accountable' for a variance from forecast. Inherent in any forecast, there is the likelihood of variances, but the variances do not necessarily mean that a single party is accountable.

As it relates to system extensions, the Company is accountable for having the requisite oversight and processes in place to ensure that the System Extension Test is being implemented and adheres to Orders G-52-07 and G-06-08.

The developer is accountable for providing the most reasonable forecast possible for the number of attachments, the timing of those attachments and the associated appliances that will be added.

The result, be it a positive or negative variance, may be a result of factors outside of the control of the parties, or may be a function of the timing or design of the reporting.

Despite the fact that the Company has consistently provided the requisite oversight and processes and developers have provided reasonable estimates, there will always be inherent uncertainty with any attachment forecast due to the volatile nature of the British Columbia housing market. For example, a developer may have provided a forecast during a high point in the housing market that was followed by an unexpected downturn resulting in a temporary, unfavorable variance. This doesn't imply that the developer was misleading the Company in its forecast, nor does it suggest that the Company was derelict in its responsibility to follow Orders G-52-07 and G-06-08.

The reported variances are a snap shot in time and may not reflect the true performance of the extension over time.

31.2 With regard to controllable business risk, is it the responsibility of the utility to determine whether or not developers' forecasts are reasonable?

Response:

The utility is responsible for administering the test in a prudent manner. The utility is also responsible for ensuring that the developer's forecasts are as reasonable as possible given the inherent volatility of the BC housing market as discussed in the response to BCUC FEVI-FEW IR 1.31.1.

Note that the developer only forecasts the anticipated attachment to the natural gas system in addition to determining the number and type of appliances. The developer is in the best position to forecast attachment timeline as they are responsible for their own build schedule and in are in a better position to determine market dynamics and the impact that might have on development timelines. The utility has discussions with the developer regarding attachment timeline, but ultimately it is the developer that determines the timeline under which they will

require service. The FEU forecast average appliance usage as approved by Commission Orders G-52-07 and G-06-08.

31.3 Is it fair to say that a reasonable forecast or a forecast based on good judgment should have equal probabilities of realizing a favourable and unfavourable variance when compared with actuals?

Response:

It is logical to assume that over time, the probabilities of realizing both favourable and unfavourable variance will be equal.

However, the timeframe and sample size in which the analysis reviews the results will greatly impact the variance, both favourable and unfavourable. As such it is virtually impossible to assign a probability to the variance due to the inherent uncertainty in forecasting attachments and the vagaries of the market dynamics. For example, the probability would depend on the BC housing market conditions and the time frame the variance is being analyzed. The variance could be looked at over a single year snap shot in time, 20 years captured in the main extension (MX) test or the 50 year life of the asset. In addition, if the analysis was undertaken immediately following a significant market event, like the 2008 housing collapse, the analysis would be skewed unfavourably. The 2009 FEVI Top 5 table above shows this unfavorable skewing, for example, in Year 1 whereby the actual attachments were 55% below forecast. This does not suggest that this is a long-term problem; rather, it is merely a reflection of the short term downturn in the housing market. Depending on the time frame chosen, and the market conditions at the time, the variance results could look completely different from one another.

32.0 Reference: Exhibit B1-76, BCUC IR 1.8.1, IR 1.9.1

Economic Base

With respect to FEVI, response to BCUC IR 1.8.1 states:

> "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." [Emphasis added]

With respect to FEW, response to BCUC IR 1.9.1 states that the same broad conclusions apply to FEW in regards to the tourism industry.

32.1 Please clarify the underlined statements. Are FEVI-FEW suggesting that business cycles (e.g., economic improvement or downturn) in the short term should not be given much weight?

Response:

FEVI and FEW would expect that, to the extent the business cycle and capital market conditions impact the cost of capital generally, they would be taken into account in setting the cost of capital for the benchmark utility. FEVI and FEW would not generally expect that the differential in equity ratio or equity risk premium between the benchmark utility and the individual utilities required by a long-term equity investor should vary with the business cycle.

In the context of stage 2 analysis, utility dependence on a cyclical industry is important from the perspective of long term risk to the extent that cyclical economic downturns could result in business failures that would have long term implications for the utility. However, the point in time in relation to the business cycle at which cost of capital is assessed in stage 2 should not determine the magnitude of the equity risk premium and/or the common equity ratio because the focus of investors is on the long term.

32.2 Would FEVI-FEW agree that the 3-5 year regular reviews of the capital structure and ROE indicate that utilities and the Commission tend to give weight to business cycles and changing market conditions?

Response:

FEVI and FEW agree that, to the extent that capital market conditions and the cost of capital generally are affected by the business cycle, the Commission takes those into account in setting the cost of capital for the benchmark utility. Please refer to the response to BCUC FEVI-FEW IR 2.32.1.

33.0 Reference: Exhibit B1-76, BCUC IR 1.10.2

Current Price Differentials – FEW

FEVI-FEW response to BCUC IR 1.10.2 states that "the 2013 residential rates for FEVI are currently set at $16.461/GJ and for FEW at $17.593/GJ."

In Table 1 for FEVI of that response, it follows that the $16.461/GJ for FEVI is the sum of lines 5-7. In Table 2 for FEW, the sum of lines 5-8 equals to $16.802/GJ which is different than $17.593/GJ.

33.1 Please clarify the difference for FEW. If applicable, please adjust accordingly.

Response:

The amounts referenced for FEW are correct. The differences between the two amounts are due to Table 2 using the weighted average commodity rate for 2013 while the response uses the most recently approved commodity rate. In addition, Table 2 excludes Riders and, more specifically, the RSAM rider while the response includes the RSAM rider. Tables 1 and 2 of the response to BCUC FEVI-FEW IR 1.10.2 were prepared using the same methodology as the tables prepared for the previous IRs referenced in that question.

The $17.593/GJ amount referenced in this question is broken out below, assuming the average FEW residential customer uses 90 GJs, so the differences between this amount and Table 2 can be identified more clearly.

Residential Midstream Rate ($/GJ) – As of July 1, 2013:	$0.935
Residential Commodity Rate ($/GJ) – As of July 1, 2013:	$3.913
Residential Delivery Rate ($/GJ) – As of July 1, 2013:	$11.422
RSAM Rider Rate ($/GJ) – As of July 1, 2013:	$0.323
Residential Basic Charge ($/GJ) – As of July 1, 2013:	$1.000
Total Residential Rate ($/GJ) – As of July 1, 2013:	$17.593

34.0 Reference: Exhibit B1-76, BCUC IR 1.11.1-1.11.3

Revenue Surplus Deferral Account (RSDA) – FEVI

FEVI provides that the following summary of the RSDA and states:

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

"… 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." (BCUC IR 1.11.2.1)

"… 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." (BCUC IR 1.11.3)

FEVI's conclusion assumes the following:

Assumptions	2013 Approved	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
Incremental Delivery Margin Increase		3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
Incremental Commodity Cost Increase		10%	10%	5%	5%	5%	2%	2%	2%	2%	2%
Cumualtive Tax Rate Increase compared to 2013		1%	1%	1%	1%	1%	1%	1%	1%	1%	1%

34.1 FEVI describes RSDA as Revenue **Surplus** Deferral Account. However, in BCUC IR 1.2.2 and BCPSO 1.1.1 it is described as Revenue **Stabilization** Deferral Account. Please confirm the correct name.

Response:

The correct name for this account, as shown in the response to BCPSO FEVI-FEW IR 1.1.1, is the "Rate Stabilization Deferral Account" as approved through Commission Order G-140-09.

34.2 If available, based on FEVI's 2013 Third Quarter Report on the GCVA and RSDA, please update the forecast GCVA as of December 31, 2013.

Response:

As filed in the FEVI 2013 Third Quarter Report on the GCVA and RSDA, dated September 6, 2013, based on the five-day average of the August 19, 20, 21, 22, and 23, 2013 forward prices for natural gas the GCVA at December 31, 2013 is forecasted to have a deficit balance of approximately $882 thousand, after tax.

34.3 Based on the volatility of the natural gas market experience in the last 5 years, is it reasonable to modify the assumption that the incremental commodity cost will not increase each and every year in the next 10 years? If so, please adjust. If not, please explain.

Response:

The table provided in response to BCUC FEVI-FEW IR 1.11.3 has been updated below with gas cost forecasts based on natural gas forward prices consistent with the forward prices used in the FEVI Third Quarter Report on the GCVA and RSDA, filed on September 6, 2013, as well as with revised revenue forecasts.

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		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
2	Incremental Gas Cost Change		-4.02%	-9.74%	1.85%	3.10%	5.02%	1.75%	1.79%	1.81%	1.82%	1.83%
3	Cumulative Tax Rate Increase compared to 2013		1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
4												
5												
6												

		2013 Approved	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
7												
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	68,076	61,444	62,581	64,522	67,760	68,948	70,180	71,450	72,751	74,083
12	Income Tax Changes	-	582	582	582	582	582	582	582	582	582	582
13		199,982	201,588	198,944	204,189	210,360	217,956	223,633	229,488	235,519	241,725	248,109
14	Less: Forecast Revenue at Existing Rates	(195,727)	(188,183)	(191,947)	(195,786)	(199,701)	(203,695)	(207,769)	(211,925)	(216,163)	(220,486)	(224,896)
15	Forecast Annual Deficiency (Surplus)	4,255	13,405	6,997	8,403	10,658	14,261	15,863	17,563	19,356	21,238	23,212
16	RSDA	(4,255)	(13,405)	(6,997)	(8,403)	(10,658)	(14,261)	(15,863)	(17,563)	(19,356)	(10,380)	-
17	Net Annual Deficiency (Surplus)	-	-	-	-	-	-	-	-	-	10,858	23,212
18												
19	**Approximate Rate Increase (Decrease), %**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**4.9%**	**10.3%**
20	**Effective Rate**	**15.725**	**15.725**	**15.725**	**15.725**	**15.725**	**15.725**	**15.725**	**15.725**	**15.725**	**16.499**	**17.348**
21												
22												
23	**RSDA Forecast**											
24	Opening RSDA Balance, net of tax	(77,773)	(75,867)	(67,235)	(63,698)	(59,225)	(53,120)	(44,101)	(33,584)	(21,448)	(7,572)	-
25	Annual (Surplus)/ Deficiency	4,255	13,405	6,997	8,403	10,658	14,261	15,863	17,563	19,356	10,380	-
26	Add: Interest on Balance	(1,714)	(1,741)	(2,218)	(2,358)	(2,409)	(2,073)	(1,651)	(1,164)	(604)	(148)	-
27	Less: Rate Rider drawdown		-	-	-	-	-	-	-	-	-	-
28	Less: Tax	(635)	(3,033)	(1,243)	(1,572)	(2,145)	(3,169)	(3,695)	(4,264)	(4,875)	(2,660)	-
29	Closing RSDA Balance, net of tax	(75,867)	(67,235)	(63,698)	(59,225)	(53,120)	(44,101)	(33,584)	(21,448)	(7,572)	-	-
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	(101,156)	(90,858)	(86,078)	(80,034)	(71,784)	(59,596)	(45,384)	(28,984)	(10,232)	-	-

The table illustrates the recent decrease in natural gas prices. Based on the change in the commodity price, all else equal, the RSDA is forecast to be fully depleted by 2022. Upon depletion, rates are forecast to increase by approximately 5% that year, followed by an additional 5% increase in 2023, for a total cumulative rate increase of 10%.

The forecast rate increases are based on the most recent forecast gas costs, and the timing of actual rate increases will inevitably vary from this forecast. In addition, the change in capital structure and ROE resulting from this GCOC proceeding will also impact the actual depletion date of the RSDA.

34.4 With regard to the 10 percent incremental commodity cost increase forecast of 2014 and 2015, what is the portion that is attributed to FEVI's hedging costs? Please specify.

Response:

As provided in the response to BCUC FEVI-FEW IR 2.34.3, the table shown in the response to BCUC FEVI-FEW IR 1.11.3 has been updated.

Accordingly, the assumptions referenced in the preamble above have been updated, and are copied below for reference:

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		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
2	Incremental Gas Cost Change		-4.02%	-9.74%	1.85%	3.10%	5.02%	1.75%	1.79%	1.81%	1.82%	1.83%
3	Cumulative Tax Rate Increase compared to 2013		1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%

The hedging currently within the FEVI gas supply portfolio ends October 31, 2014; the cost of hedged gas is not affected by changes in the market price of natural gas.

Further, there is no hedging for 2015 and beyond, which increases the exposure of FEVI's cost of gas to volatility in the market price of natural gas.

34.5 FEVI anticipates a 15 percent rate increase in 2020, and 2 percent annually thereafter. Has FEVI considered smoothing out the projected rate increase which may reduce the higher risk in delivery rates as compared to FEI?

Response:

The FEU are currently involved in a Reconsideration Process for the Common Rates, Amalgamation and Rate Design Application. In the absence of approval for amalgamation and the adoption of common rates, FEVI will deal with the pending rate increases, as well as alternative solutions, in a future application.

However, rate smoothing may entail implementing rate increases sooner than 2020, as opposed to only pushing out portions of the increase to future years as the question appears to assume. In any event, an investor will take a long-term perspective on business risk, and the underlying risk to investors over the long term is still present despite whatever smoothing mechanism is put in place.

34.6 Given that the RDSA is projected to have a surplus until 2020, what is the basis to establish a higher equity thickness and equity risk premium now when this risk based on FEVI's projection will not be realized until 2020?

Response:

Based on the updated table provided in the response to BCUC IR 2.34.3, the RSDA is projected to have a surplus until 2022. However, as demonstrated by the recent volatility in commodity prices, there is the possibility that commodity prices could increase, or other factors could arise, that lead to a depletion of the RSDA sooner than 2022.

The elimination of the RSDA surplus, which is primarily a rates issue, is just one of the risks faced by FEVI. Investments in utility assets are long-term investments, and FEVI's financial future would be of concern to a potential investor. The depletion of the RSDA has prompted credit ratings agency Moody's to state in its 2013 report "We expect FEVI's cash flow and financial metrics to weaken materially beginning in 2013". The utilization of the RSDA to maintain existing rates does not address the cash flow issue that was discussed by Moody's in its report.

There are also four broad categories of risk faced by FEVI today that differentiate FEVI from FEI, which are expected to continue into the future, and for which there is no simple solution. These risks are detailed in the filed evidence, and are also summarized below:

1. **Smaller size and greater asset concentration:** FEVI is a significantly smaller natural gas distribution utility than FEI, in terms of service area, customers, rate base and revenues. The concentration of assets within a small service area precludes FEVI from diversifying its risk to the same extent as FEI.

2. **Less diverse customer and economic base:** FEVI has a less diverse economic and customer base than FEI. It also relies heavily on throughput and revenue from two major industrial customers. One of those customers, the VIGJV, is a joint venture of pulp mills, whose natural gas demand over the long-term will depend on the fortunes of the pulp and paper industry. This less diverse customer base, and the concentration of customers in particular industry segments, makes FEVI subject to greater throughput and revenue risks.

3. **Energy price competitiveness:** FEVI continues to face much higher effective per gigajoule natural gas rates than FEI, which presents a greater challenge from the perspective of energy price competitiveness given BC Hydro's postage stamp rate

structure. In FEVI's case, the surplus in the Revenue Surplus Deferral Account (RSDA) will only provide temporary relief from rate increases associated with the elimination of the Provincial royalty revenues in 2011.

4. **Supply interruption risk:** FEVI obtains natural gas via FEI's coastal transmission system. FEVI is further downstream of the FEI coastal transmission system so by this very nature its 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.

These are the risks facing FEVI today and into the foreseeable future. Based on these risks, it is reasonable to establish a higher equity thickness and equity risk premium for FEVI.

35.0 Reference: Exhibit B1-76, BCUC IR 1.14.1-1.16.6

Letters L-43-13 and L-44-13, 2013/2014 Annual Contracting Plans

Supply Interruption Risk

As established by Order G-130-06, the Rules for Natural Gas Energy Supply Contracts states that "Public utilities must submit and obtain Commission acceptance of annual gas contracting plans prior to entering into significant gas supply arrangements for each gas contract year."

In the 2013/2014 Annual Contracting Plans (ACP) of FEI and FEVI, the objectives of the ACP are:

1. To contract for resources which ensure an appropriate balance of cost minimization, security, diversity and reliability of gas supply in order to meet the core customer design peak day and annual requirements.
2. To develop a portfolio mix that incorporates flexibility in the contracting of resources based on short term and long term planning, and evolving market dynamics.

35.1 To what extent FEVI's and FEW's security of supply risk is addressed through the ACPs given the ACP objectives? Please explain.

Response:

Security of supply risks faced by FEVI and FEW fall into two general categories. The first relates to supply interruption risks associated with the transmission and distribution systems of FEVI and FEW that have single points of failure and that need to traverse rugged terrain, including (for FEVI) requiring marine crossings. The second relates to the need to secure and manage gas supply resources up stream of FEVI and FEW's systems that are required to meet customers' demand for the natural gas commodity itself. The ACPs help to manage security of supply risk associated with this second category but do not address any of the risks associated with the need to operate FEVI and FEW's transmission and distribution systems.

The responses to GCOC Stage 2 BCUC IRs 1.14.2 through to 1.16.6 highlight the supply interruption risks associated with the transmission and distribution systems of FEVI and FEW, something that the ACPs are unable to address.

In Exhibit B1-71, evidence of FEVI and FEW, Tab A, page 24 and Tab B, pages 11-12, distinguishes between security of supply risks related to the transmission and distribution systems of FEVI and FEW and those related to securing and managing gas supply resources up stream of these systems.

36.0 Reference: Exhibit B1-76, BCUC IR 1.14.1- 1.16.6

Supply Interruption Risk

FEVI-FEW provide the following map showing the gas system of FEI, FEVI, and FEW:

36.1 To summarize the supply interruption risk, please comment if FEVI and FEW would agree to the summary below. Make any adjustments as necessary.

	Outage Location	Affected Utility	Potential Mitigation	Repair Time
1	One line of the twinned submarine crossing	FEVI	Mt. Hayes LNG facility, the other submarine crossing	Long
2	Both lines of the twinned submarine crossing	FEVI	Mt. Hayes LNG facility	Long
3	Between Coquitlam and Squamish	FEVI and FEW	For FEVI – Mt. Hayes LNG facility, line pack For FEW – Mt. Hayes LNG facility, line pack, LNG tankers from Tilbury	Short
4	Between Squamish and Whistler	FEW	Line pack, LNG tankers from Tilbury	Short

Response:

The summary table as outlined in this IR question needs to be qualified as follows:

1. All the mitigation activities highlighted in the summary table are only available for the management of short term supply interruptions. There is no mitigation activity identified that is capable of relieving a long term supply interruption.

2. While the highlighted potential mitigation activities are valid, they are not necessarily fully capable of maintaining service to the affected utility for the outage scenarios as outlined.

3. As stated in the response to BCUC FEVI-FEW IR 1.15.2.1, the mitigation activities outlined in the summary table for addressing an outage between Squamish and Whistler would not be sufficient to supply the demand of FEW.

4. The repair time for outage between Coquitlam and Squamish, and between Squamish and Whistler could be short or long. As stated in the response to BCUC FEVI-FEW IR 1.15.4.1, in the event of damage to a section of the FEVI's system, a temporary repair with a potential throughput capacity reduction could be constructed. However, a permanent repair would require considerable time to plan, design, and construct.

36.2 If one of the twinned submarine crossing breaks, will the other working submarine crossing be able to serve FEVI customers? Please describe this scenario for both summer and winter seasons.

Response:

Each pair of twinned submarine crossings is designed to provide 100% backup at any time in both summer and winter seasons, such that if one fails the other one will provide the full throughput capacity needed to serve all of FEVI's customers.

36.3 Under what circumstances and what is the likelihood that both lines of the twinned submarine crossing breaking?

Response:

One possible scenario to cause both lines of a twinned submarine crossing to fail would be in the event of heavy anchors from a large marine vessel sinking through the sediment cover over the lines and snagging both lines simultaneously.

Each pair of twinned submarine crossings was designed and constructed with added protection, such as heavy pipe wall thickness and concrete external coating, and laid down with separation in order to minimize the likelihood that a single event will simultaneously damage both lines. Additionally, these lines are actively monitored for immediate isolation from one another if one line is damaged. This design and operational redundancy provides the twin submarine crossing with high reliability and therefore the likelihood of both lines of the twinned submarine crossing breaking at the same time is low. However the consequence of a failure of both lines is significant.

36.4 If the submarine crossing outage occurs between Powell River and Texada Island, would that interrupt FEVI's service to customers?

Response:

If such an outage of the submarine crossing between Powell River and Texada Island were to occur, the submarine crossing to Powell River would be isolated from the rest of FEVI's transmission system and the interruption of service would be limited to FEVI's customers located at Powell River.

36.5 If an outage occurs between Coquitlam and Whistler, would line pack be available to serve FEVI and FEW customers? If so, please describe such scenario.

Response:

The interpretation of outage between Coquitlam and Whistler is assumed to mean that the FEVI transmission system between Coquitlam and Squamish and between Squamish and Whistler would not be available. Under such circumstances, there would be no line pack available to serve FEW customers but some line pack would be available to serve FEVI customers located downstream of Squamish.

36.6 If an outage occurs between Squamish and Whistler, would line pack be available to serve FEW customers? If so, please describe such scenario.

Response:

A complete outage between Squamish and Whistler implies that the Whistler Pipeline, which would normally contain some short term usable line pack, would not be available. Under such circumstances, line pack would not be available to serve FEW customers.

However, if the outage is localized to a section of the Whistler Pipeline, the remaining pipeline section downstream of the outage would provide some usable line pack to be able to maintain service to FEW's customers for a brief period of up to a few hours depending on the distance of the incident site from Whistler and the customer load.

37.0 Reference: Exhibit B1-76, BCUC IR 1.15.4.2- 1.16.6

Exhibit B-1, PNG (N.E.) Compressed Natural Gas Virtual Pipeline Application

Supply Interruption Risk – FEW

FEVI-FEW response to BCUC IR 1.15.4.2 states:

> "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."

FEVI-FEW response to BCUC IR 1.16.1 further states:

> "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."

Currently in a proceeding before the Commission, the Pacific Northern Gas (N.E.) Ltd. Application for a Certificate of Public Convenience and Necessity to Acquire, Construct, Own and Operate a Compressed Natural Gas (CNG) Virtual Pipeline between the Communities of Dawson Creek and Tumbler Ridge shows, on page 22 of Exhibit B-1, that under certain customer circumstances, PNG provided supplemental natural gas via trucking of CNG from Dawson Creek to Tumbler Ridge as a means to providing firm service on a temporary basis.

37.1 Is trucking CNG to FEW via a third-party supplier or via FEI a viable option to serve FEW customers if an outage occur at the Whistler Lateral to FEW?

Response:

Portable CNG transport is not a viable option.

As stated in the response to BCUC FEVI-FEW IR 1.16.1, the portable LNG supply is not sufficient to supply the total demand of FEW. Compared to portable LNG transport, portable CNG transport carrying natural gas at only 40% of the energy density of LNG would require 2.5 times more trucks. Therefore, the inferior logistics of portable CNG transport does not make it a viable option to serve FEW customers under an outage of the Whistler Lateral. Instead, the emergency portable CNG supply could be used as a limited supplement to the emergency portable LNG supply.

37.1.1 If so, please provide an example of how this option might work. Please describe the estimated days of supply and the assumptions.

Response:

Portable CNG transport is not a viable option. Please refer to the response to BCUC FEVI-FEW IR 2.37.1.

37.1.2 Please compare the CNG trucking alternative to the portable LNG supply in light of supply interruption risks.

Response:

CNG trucking alternative is not a viable option to manage the outage risk to FEW. Please refer to the response to BCUC FEVI-FEW IR 2.37.1.

38.0 Reference: Exhibit B1-76, BCUC IR 1.17.1.2, IR 1.21.1

High Risk Utilities in Canada

Ms. McShane refers to Heritage Gas and Enbridge Gas New Brunswick as examples of Canadian utilities that are higher business risk than FEW. Their allowed ROEs and capital structures are summarized below and compared to the cost of capital requests for FEVI and FEW.

	Debt/Equity Ratio	Allowed ROE	Equity Risk Premium in basis points (bps)	Burner Tip Rate Comparison
Heritage Gas	55/45	11.0%	200 bps above Nova Scotia Power's 9.0%	$15.351/GJ (residential base charge and gas cost). Monthly customer charge of $21.87.
Enbridge Gas New Brunswick (EGNB)	55/45	10.9%	275 bps above 8.15% benchmark	$21.17/GJ (small general service delivery charge and gas cost). Single family dwelling included in small general service. Monthly $16 customer charge.
Cost of Capital Proposal for FEVI	56.5/43.5	9.25%	50 bps above 8.75% benchmark (2013)	$14.325/GJ (residential charge and gas cost) Monthly $10.70 basic charge.
Cost of Capital Proposal for FEW	55/45	9.50%	75 bps above 8.75% benchmark (2013)	$16.27/GJ (residential delivery charge and commodity charge) Monthly $7.64 basic charge.

Source:
http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasTariffs/Documents/Tariffs_TermsandConditions_FEVI.pdf
http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasTariffs/Documents/Tariffs_termsandconditions_Whistler.pdf

38.1 Do FEVI-FEW agree that FEVI's and FEW's bundled cost per GJ as well as their monthly basic charges compare favourably with EGNB and Heritage?

Response:

A clarification to what is stated in the table: FEW's current BCUC approved variable charges per GJ (effective July 1, 2013) sums up to $16.593 (residential delivery and gas cost recovery charge, inclusive of all applicable rate riders). Also, FEVI's and FEW's rates as summarized in the table above do not account for the BC Provincial Government Carbon Tax, set at $1.4898 per GJ.

Both FEVI's and FEW's bundled variable charges per GJ are roughly comparable to Heritage's bundled charges per GJ and are lower than EGNB's. However, FEVI's and FEW's daily basic charges (multiplied by 31 days in the referenced table for comparison purposes) are lower than EGNB's and Heritage's monthly basic charges.

FEI's current residential variable charge per GJ (effective July 1, 2013) sums up to $8.502 (residential delivery, gas cost, and midstream recovery charges and all applicable rate riders). This rate is $5.823 lower than FEVI's variable charge per GJ and $8.091 lower than FEW's variable charge per GJ, which is a significant difference. As stated on page 16 of Appendix A, the average residential rates charged by FEVI and FEW at the burner tip (per GJ) are almost 60 percent higher for FEVI and more than 65 percent higher for FEW when compared to FEI's rates. . Therefore, FEVI and FEW's challenge from a price competitiveness perspective lies within the current and future higher delivery rates than the benchmark utility.

39.0 Reference: Exhibit A2-59, Moody's Regulated Utility Methodology; Exhibit B1-20, BCUC IR 1.48.2; Exhibit B1-71, p. 10 & Tab B, p. 13; Exhibit B1-73, BCUC IR 1.7.6

Credit Metrics

FEVI-FEW state the potential for a credit rating downgrade is of immediate concern for FEVI (Exhibit B1-71, page 10). In Tab B on page 13 of Ms. McShane's testimony in Exhibit B1-71, she noted FEVI's stronger credit metrics as compared to FEI.

Exhibit A2-59 contains the following excerpt from the Moody's Regulated Utility Methodology page 27:

> "In Canada, regulation of electric and gas utilities is overseen by independent, quasi-judicial provincial or territorial regulatory bodies… Moody's views the supportiveness of the Canadian business and regulatory environments to be positive for regulated utility credit quality and believes that these factors , to some degree, offset the relatively lower ROEs and higher deemed debt components typically allowed by Canadian regulatory bodies for rate-making purposes… relatively low ROEs and higher deemed debt levels that are generally characteristic of Canadian utilities, for a given rating category, these entities often have weaker credit metrics than their international peers." [Emphasis added]

In Stage 1 of the GCOC proceeding, FortisBC Utilities (FBCU) response to BCUC IR 1.48.2 states:

> "… All other things equal (e.g., embedded cost of debt, ROE, capital structure ratios), as the income tax rate declines and the income tax allowance forms a relatively smaller portion of Earnings before Interest and Taxes (EBIT) and Earnings before Interest, Depreciation and Amortization (EBITDA), the pre-tax credit metrics, e.g., EBIT Interest Coverage, EBITDA Interest Coverage and EBITDA to Debt, will be weaker." [Emphasis added] (Exhibit B1-20)

FortisBC Inc. (FBC) response to BCUC IR 1.7.6 states "… FBC obtained information regarding the increase in BC's general corporate income tax rate from 10% to 11% on April 1, 2013…" (Exhibit B1-73)

39.1 Please confirm that the income tax rate increase means that the pre-tax credit metrics will be stronger for FEVI, holding all else equal.

Response:

Confirmed. Given there is only one credit metric by DBRS that considers pre-tax cash flow and the increase in taxes is only 1%, FEVI does not anticipate the tax rate change would have a material impact to its credit metrics. Also, while the marginal rate has increased, it is not necessarily the effective rate of tax once available credits and deductions are considered.

39.2 In light of FEVI's stronger credit metrics as compared to FEI, as well as Moody's view that Canadian utilities often have weaker credit metrics, should these factors mitigate FEVI's concern of a Moody's credit rating downgrade? If not, why not?

Response:

No, the factors noted in the question do not mitigate FEVI's concerns of a downgrade. Historically, stronger credit metrics may have played a part in supporting a credit rating at the same level as FEI, as did the potential for amalgamation and common rates. However, the reality is that Moody's has now put FEVI on negative outlook for a possible downgrade, which is a clear indication that a downgrade is a more likely outcome. Furthermore, Moody's states in its June 2013 report, "We expect FEVI's cash flow and financial metrics to weaken materially beginning in 2013". Historically, FEVI's credit metrics have benefited from government royalties and surplus cash flow due to the build-up of the RSDA, however, this will not be the case going forward.

40.0 Reference: Exhibit B1-76, BCUC IR 1.22.5; Appendix A2-58

Market Penetration of Natural Gas Utilities - Comparison

In Ms. McShane's response to BCUC IR 1.22.5, she provided some estimates of market shares of fuel for space heating and water heating in Nova Scotia and B.C.

Based on her estimates from response to BCUC IR 1.22.5 and the results from the 2008 Residential End Use Study (REUS) that was issued on November 30, 2009 (Appendix A2-58), staff summarized in the table below the market shares for the service areas served by FEVI, FEW and Heritage Gas.

Comparison of Market Penetration, Heritage Gas, FEVI and FEW

	Data from IR 1.22.5		Data from 2008 REUS		
	Nova Scotia	B.C.	FEVI (3)		FEW (4)
Space Heating Fuel (2010)			**Space Heating Fuel (2008)**		
Electric	19.9%	32.6%	26.3		29.5
Oil	62.8%		1.6		0.0
Natural Gas (1)	17.3%	53.5%	71.3	(5)	67.6
others (2)		13.9%	0.8		2.9
	100.0%	100.00%	100.0		100.0
Water Heating Fuel (2010)			**Water Heating Fuel (2008)**		
Electric	21.7%	17.8%	20.0		43.5
Oil	62.8%		0.0		0.0
Natural Gas (1)	15.5%	80.7%	79.8	(5)	56.1
others (2)		1.5%	0.3		0.5
	100.0%	100.0%	100.0		100.0

Notes:

(1 the share is calculated as the difference between total market and electric and heating oil.

(2) the share is calculated as the difference between total market and electric, natural gas and oil

(3) FEVI is formerly known as TGVI

(4) FEW is formerly known as TGW

(5) includes propane gas

40.1 Is the REUS conducted in 2008 and published in November 2009 the latest available information on space heating and water heating fuels in the FEVI and FEW service areas? If not, please provide an update to the above table. If yes, please confirm the data in the table above.

Response:

The 2008 Residential End Use Study (REUS) surveyed existing FEU residential natural gas customers only. The data provided in the report for space and water heating therefore refers only to the percentage of FEU customers who use natural gas as their primary fuel to provide space and water heating not the overall percentage of BC residents who use natural gas for these purposes. The estimates from Ms. McShane are for the total BC residential market, not the sub-set of natural gas customers. It is therefore inappropriate to compare the two tables.

A REUS was undertaken in December 2012 and the results are currently been reviewed for accuracy. However, preliminary results indicate that the percentage of customers in both the FEVI and FEW service territories using natural gas as their primary space and water heating fuel has declined when compared to 2008.

40.2 From the figures in the table above, is it fair to conclude that FEVI–FEW have, respectively, higher natural gas market penetrations in their service territories than Heritage Gas?

Response:

It is fair to conclude that both FEVI and FEW have higher market penetration in their service areas than Heritage Gas. However, the calculations provided in the table above are not correct for Heritage Gas for two reasons. First, the data are for the entire province of Nova Scotia, which Nova Scotia Power serves, but Heritage Gas does not. Heritage Gas' distribution system is concentrated in the Halifax-Dartmouth region. Second, the percentage of the residential space and water heating market accounted for by natural gas in the province of Nova Scotia in 2010 is not the residual after accounting for electricity and oil; "other" energy sources account for a significant percentage of the total.

40.3 Would higher penetration of natural gas at between 56 percent to 80 percent for water heating and 68 percent to 71 percent for space heating compared to Heritage Gas' respective 16 percent and 17 percent a good indicator of the much lower competitive risk for FEVI-FEW?

Response:

Please note that the calculations upon which this question is based are not correct, for the reason described in the response to BCUC FEVI-FEW IR 2.40.2. FEVI and FEW agree, however, that the low market penetration of natural gas in Nova Scotia represents a reasonable indicator of the higher competitive risk faced by natural gas in Nova Scotia. Neither FEVI nor FEW is requesting a combined common equity ratio/equity risk premium of the same magnitude allowed for Heritage Gas.

40.4 Please provide a similar column showing the natural gas market penetration of Enbridge Gas New Brunswick small general service class to the extent the information is available.

Response:

To Ms. McShane's knowledge, there are no Enbridge Gas New Brunswick (EGNB) specific data available. The table below shows the most recent available consumption data for the residential sector for the entire province of New Brunswick, not only where natural gas is available. Natural gas is only available in 10 communities in southern New Brunswick.

Space Heating Fuel (2010)	
Electric	38.3%
Oil	36.8%
Natural Gas	1.4%
Others	23.5%
Total	100.0%
Water Heating Fuel (2010)	
Electric	71.5%
Oil	20.0%
Natural Gas	4.4%
Others	4.1%
Total	100.0%

41.0 Reference: Exhibit B1-76, BCUC IR 1.19.1

Credit Metrics

In its response, FEVI says that it has applied the adjusted scenarios to the 2012 data on a retroactive basis.

41.1 Please confirm that FEVI has used the allowed benchmark ROE of 8.75 percent when calculating the credit metrics.

Response:

Confirmed.

42.0 Reference: Exhibit B1-77, BCPSO IR 1.12.1; Exhibit B1-76, BCUC IR 10.2

Customer Retention and Growth

The response to BCPSO IR 1.12.1 states that the 2011 Energy Source Usage Preferences Study showed that half of current FEU customers are uncommitted to natural gas. The response in the same question further states that if given a choice of heating method in a new home, a significant percentage (64%) of respondents would opt for a heat pump.

"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." (Response to BCUC IR 1.10.2)

42.1 Is the Energy Source Usage Preference Study an annual study? Please provide the findings of these studies from 2002 to 2011 with respect to the respondents' indicated commitment to natural gas. Please provide the findings by service area if the data are available.

Response:

The Energy Source Usage Preference Study uses a proprietary methodology of TNS Global Research called the "Conversion Model." The model has been used in various studies starting in 2006, and repeated in 2007, 2008 and 2011. It categorizes respondents into four groups, including:

1. **Committed Users** – Users who are psychologically committed and (assuming they were able to), would be unlikely to switch their home heating system.

2. **Uncommitted Users** – Users who are uncommitted and would be interested at looking at alternative heating systems or would be most likely to defect to another heating system, if they could.

3. **Open Non-Users** – Non-users of a particular heating system who are most likely to be acquired because they are interested in an alternative system or are equally attracted to this alternative heating system as they are to their current heating system.

4. **Unavailable Non-Users** – Non-users of a heating system who are not likely to be acquired but may become available later on, or who are not available because they strongly prefer their current heating system.

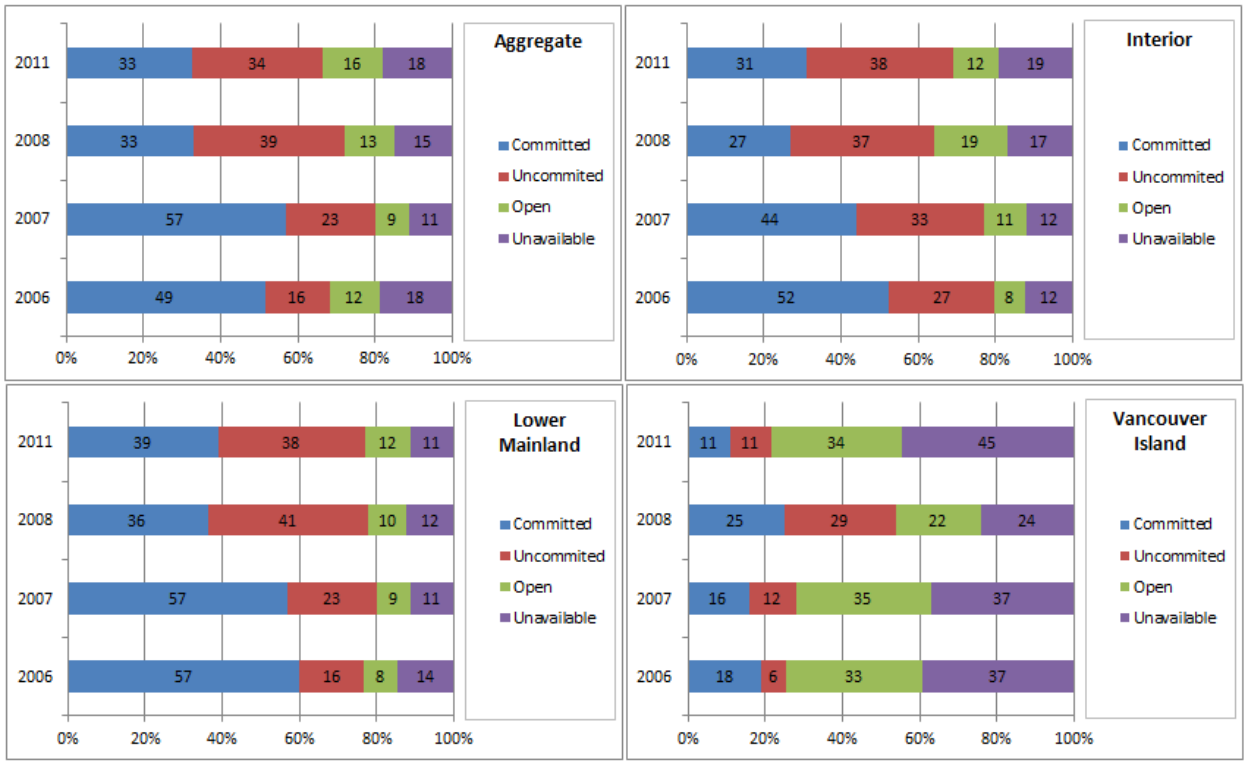
Regional and aggregate consumer commitment levels for natural gas home heating systems as identified in each research wave are presented in the table and graphs below. Trending since 2006 suggests that commitment towards natural gas as a preferred heating fuel have declined.

Figure 1: Consumer commitment towards natural gas for space heating by region [1]

	2006	2007	2008	2011
Interior				
Committed	52	44	27	31
Uncommited	27	33	37	38
Open	8	11	19	12
Aware Unavailable	12	12	17	19
Lower Mainland				
Committed	57	57	36	39
Uncommited	16	23	41	38
Open	8	9	10	12
Aware Unavailable	14	11	12	11
Vancouver Island				
Committed	18	16	25	11
Uncommited	6	12	29	11
Open	33	35	22	34
Aware Unavailable	37	37	24	45
Aggregate				
Committed	49	57	33	33
Uncommited	16	23	39	34
Open	12	9	13	16
Aware Unavailable	18	11	15	18

[1] Compiled data from TNS Conversion Model results, 2006, 2007, 2008 and 2012. Regions by year may not sum to 100 because some respondents were indeterminate (i.e., do not care which energy they use), and/or rounding occurred.

Figure 2: Commitment levels by year and region (percentage of respondents)



42.2 In the view of FEVI-FEW, does the finding that "half of current FEU customers are uncommitted to natural gas" mean that half the FEU customers could be lost in the near term? What are the probabilities of losing these customers?

Response:

No, Conversion Model information is gathered to help FEU evaluate evolving consumer preferences for heating systems and how these changes may influence natural gas market share in the long-term. Insight informs FEU communication activities to help educate consumers about the long-term value of natural gas heating options. Without these educational efforts model results suggest that customer commitment to natural gas heating systems will continue to erode across all regions and market penetration rates will decline.

42.3 When FEU customers were asked about how they would choose when "given a choice of heating method in a new home", were they provided with the upfront capital costs and energy costs for the alternatives? If so, please provide in your response the information shown to the respondents of the study. If not, why not?

Response:

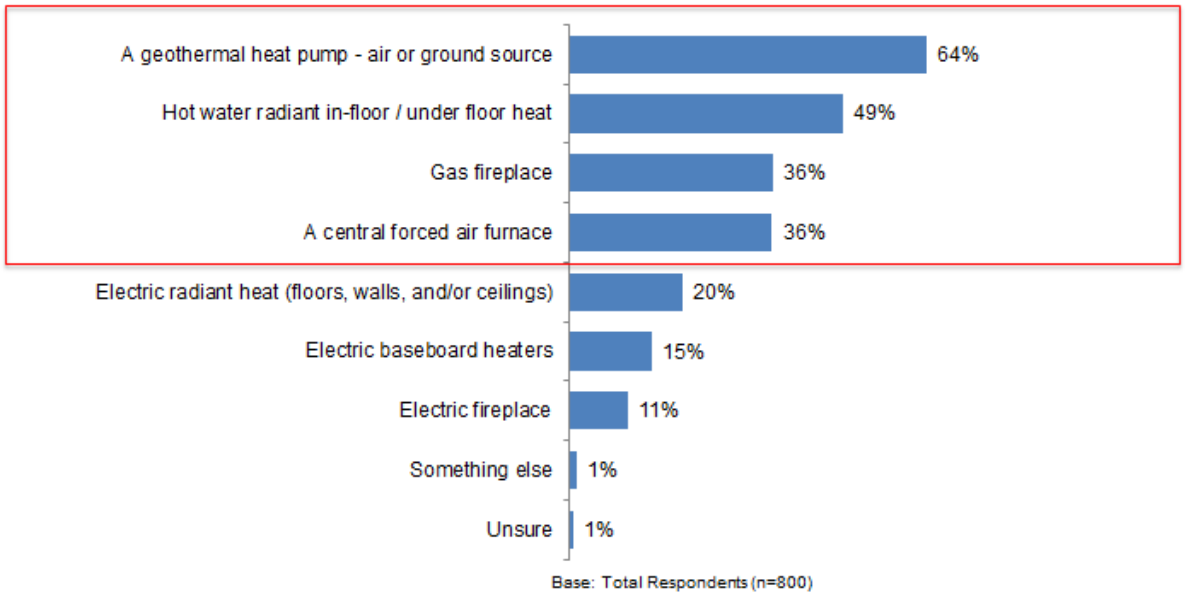
This survey was intended to provide insight into heating systems that they would likely consider if building a new home. Responses provide insight into which heating systems might reasonably be expected to be included in a more thorough evaluation. Results presented should be considered attitudinal, reflecting consumer preferences based on their existing knowledge about the alternatives posed.

A more thorough economic analysis would have required a more complex questionnaire and was considered out of scope for this project. In addition, providing case scenarios with hypothetical information presupposes that customers consistently engage in an exhaustive economic analysis of capital and ongoing operating costs when selecting a heating system. Heating systems are typically selected by the builder or developer and long term operating costs may not be considered.

Respondents were provided with a list of space heating options for a new home and asked to identify those that appealed. An average of 2.3 energy sources was selected, with geothermal heat pumps emerging as most popular stated choice. The following question was asked: "Imagine again that you are building a new home. You need to decide on a system of heating the home. I'm going to read you a list of space heating systems. Based on what you know about these systems which ones would you consider?"

The following chart depicts the results from the 2011 study.

Figure 1: Heating System Preferences[2]



NOTE: figures in the above chart add to more than 100% due to multiple responses.

[2] 2011 Energy Source Usage Preferences Study – Topline Results, TNS Canada, December 2011, page 29.