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January 22, 2016

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary and Director

Dear Ms. Hamilton:

Re: Project No. 3698852

FortisBC Energy Inc. (FEI or the Company)

Application for its Common Equity Component and Return on Equity (ROE) for 2016 (the Application)

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 2

On October 2, 2015, FEI filed the Application referenced above. In accordance with Commission Order G-177-15 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

46.0 Reference: Exhibit B-9, BCUC IR 1.1 and 2.1

Business profile of Amalgamated FEI

FortisBC Energy Inc. (FEI) states that it would have requested the same return on equity (ROE) and capital structure, even if it did not amalgamate. It further states its position that investors' expected return has not been affected by amalgamation.

According to FEI, its main rationale for its request to increase its equity thickness relates to the upward trend in business risk, in particular the increase in the political risk category, and its relatively weak financial metrics. Table 1.1.1 shows the business profile of FEI, in amalgamated form, between 2004 to the present.

46.1 Under Sales/Transport Volumes (TJ), the 2015 (Approved) volume is at 176,035 TJ. Please explain the low sales/transport volumes for the period 2008 to 2010 and why the volumes rebounded in 2011 and thereafter.

Response:

The Sales/Transport volumes shown in the response to BCUC IR 1.1.1.1 represent the combined volumes for all the non-bypass customers, consisting of multiple rate classes representing different types of customers.

Therefore, it is difficult to isolate any one particular reason for fluctuations in the overall volumes. However, FEI has undertaken some analysis and provides the table below which shows the rate classes with the largest changes for 2008 to 2014, using 2007 as the base year. To simplify the analysis, Lines 1 - 5 of the table are the pre-amalgamation FEI volumes only.

As shown in the response to BCUC IR 1.1.1.1, total actual volumes decreased 3.5 PJs in 2008, 5.7 PJs in 2009 and 3.5 PJs in 2010, when compared to the base year of 2007. These decreases are shown in Line 7 in the table below, along with the changes for the years 2011 through 2014 compared to 2007.

As shown below, volumes did improve in 2011 but it was a temporary "rebound", as both the 2013 and 2014 actual volumes were lower than the 2007 volumes, consistent with the 2008 to 2010 period. The table shows that there are consistent trends across all the major rate categories with the exception of Rate Schedule 22 customers, which are highly variable for reasons such as fuel-switching and customers moving on and off the system.

Line	Volumes (PJs)	2008	2009	2010	2011	2012	2013	2014
1	Rate 1 - Residential	(1.8)	(0.6)	(0.6)	(1.7)	(0.9)	(2.5)	(2.2)
2	Rates 2/3/23 - Commercial	0.4	1.8	1.1	2.7	3.3	2.6	3.3
3	Rate 22 - Industrial	(1.3)	(5.0)	(1.5)	1.1	4.9	(0.7)	(1.2)
4	Rates 5/25 - Industrial	(0.7)	(1.9)	(2.7)	(2.5)	(3.0)	(3.4)	(3.5)
5	Rates 7/27 - Industrial	(0.0)	0.4	0.5	1.2	1.0	2.1	1.2
6	All Other Rate Classes inc. FEVI/FEW changes	(0.1)	(0.4)	(0.4)	(0.3)	(0.2)	(0.3)	0.2
7	**Total Volumes Change compared to 2007**	**(3.5)**	**(5.7)**	**(3.5)**	**0.5**	**5.1**	**(2.2)**	**(2.2)**

46.2 Please explain the dip in the average number of customers (residential, commercial and industrial) in 2012. Was this dip expected and in the FEI load and revenue forecasts? Was FEI at risk from failing to earn its forecast revenue or was the forecast variance captured by a variance account?

Response:

This dip in the average number of customers in 2012 was related to a one-time adjustment to the number of customers that resulted when FEI converted its Customer Information System to SAP (SAP has a different method for counting customers than the previous system). This adjustment resulted in a one time reduction in the average number of customers. This was discussed in Section C 1.3.1 of FEI's 2014-2018 PBR Application:

1.3.1 SAP Account Adjustment

FEI's new CIS, which became operational as of January 1, 2012, has enabled a more accurate method of counting customers.

In the previous CIS, the number of customers was determined at month-end using an algorithm that counted the number of services (meters) that were installed at a premise, where:

- The meter was not disconnected during the entire reporting period (month); or,
- The meter was disconnected during the reporting period, but a customer was attached to that premise for at least one day in that reporting period.

This means that to be considered a customer, the service had to be active at some point during the month.

In the new SAP-based CIS, the algorithm for determining the number of customers is to count the number of valid contracts (for natural gas service) that are in effect on the

reporting date (which can be any day of the month). For purposes of reporting monthly customer counts, the FEU use the mid-month report (based on the 15th of the reporting month).

A customer in the new SAP-based CIS is defined as a valid contract to provide natural gas service. This definition results in a different customer count from that of the previous CIS in those situations where a premise becomes vacant or meters are disconnected during the reporting period. Under the new system these vacant premises or meter disconnects no longer have a valid contract as of the day the premise becomes vacant or the meter is disconnected. This is in contrast to the previous CIS where there was still an installed meter that received service during the reporting period. For example, if a customer was disconnected on January 10, under the previous CIS they would be reported as a customer for the month of January (as a meter would have been attached to that premise for at least one day during the month of January). Under the new CIS, however, they would be excluded.

Further discussion of this change in customer counts was provided in a letter from the FEU filed with the Commission on January 28, 2013. The letter can be found in Appendix E4.

The mathematical result of a decrease in the number of customers with no change in delivery volumes is an increase in the use per customer (volumes divided by number of customers equals use per customer) in residential and commercial rate classes. These one-time increases are not indicative of recent trends and were not included in the calculation of the forecasted use rates.

As stated in the quoted extract from the PBR Application, this adjustment in the number of customers did not impact the actual or forecast overall load or revenue in 2012, as they remained the same, and as a result FEI's revenue forecast was not affected, and there was no amount to be recorded in a deferral account. However, the number of customers and the use per customer from 2012 forward are not directly comparable to the years prior to 2012.

46.3 For the customer profile by demand (TJ), please confirm that only residential segment is weather normalized but not the commercial and industrial.

Response:

Not confirmed.

Both residential and commercial segments are weather normalized. The industrial segment is not weather normalized.

47.0 Reference: Exhibit B-9, BCUC IR 3.1 and 3.2; Exhibit B-7, AMPC IR 2.13

Expected Rate of Return on Assets from pension funds

According to FEI, the Expected Rate of Return on Assets (EROA) as forecasted was to be used solely for determining the pension accounting expense and obligation. FEI is of the position that it is not appropriate or relevant in the determination of FEI's own ROE.

The response to BCUC IR 3.1 indicated the following returns in regards to the pension return expectations of the FortisBC companies as of December 31, 2014:

Canadian equities	7.00%
US Equities	7.40%
Non-North American equities	7.40%
Bonds	3.45%
Real estate	6.50%

FEI noted that these figures had been provided by its actuarial consulting firm, Towers Watson. FEI stated that these were geometric returns and that the forecasted 7.0 percent geometric return on Canadian equities provided by the actuary was equivalent to approximately 9.0 percent, on the arithmetic basis.

In response to BCUC IR 3.2, FEI referenced at footnote 3, a textbook by Roger Morin, New Regulatory Finance.

In response to AMPC IR 2.13, FEI provided an AonHewitt Capital Market Report dated October 6, 2015. The introduction to the report indicates that it provides 10-year forward looking capital market assumptions. Page 18 of the report indicates that AonHewitt expects the 10-year forward average annual return on Canadian equities to be 8.0% and 6.8% on a compound basis.

47.1 Please confirm that at page 133 of the referenced textbook, Roger Martin stated: "On average investors expect to receive their target return. This target expected return is in effect an arithmetic average."

Response:

Confirmed that this statement is made on page 133 of New Regulatory Finance, 2006, by Roger A. Morin, PhD. Also on this same page is the statement "the arithmetic mean, is the correct one for estimating discount rates and the cost of capital".

47.2 Does FEI agree that the geometric mean is a backward looking measure of performance, that is, it provides a measure for comparing past performance across different securities or portfolios?

Response:

Achieved or retrospective returns generally utilize the geometric average. However a geometric mean could be used as either a backward or forward looking measure of performance, depending on the context.

47.3 Did Towers Watson state that its return expectations were geometric returns and that the 7.0 percent Canadian equity return forecast was equivalent to approximately 9.0 percent on the arithmetic basis? If so, please provide quotes from Towers Watson.

Response:

Per Towers Watson: "Towers Watson confirms that the expected rate of return for Canadian equities produced by our model represents the geometric rate of return over a 20-year period. The expected average geometric 20-year rate of return for Canadian equities is 7.0% per year. This is equivalent to an average arithmetic rate of return of approximately 9.0% per year."

47.3.1 Please provide the formulas for the arithmetic mean and the geometric mean. Please provide the statistical properties of the relationship that would convert a forecast 7.0 percent geometric on Canadian equities to an approximate 9.0 percent arithmetic return. Please provide details of the calculation.

Response:

FEI has discussed this matter with Towers Watson for the response. The Towers Watson model develops pension plan asset annual rates of return for a 20-year period through a stochastic forecast. The model then determines the geometric rate of return and the arithmetic

rate of return for this 20-year period. This model then produces 5,000 such stochastic forecasts and the returns provided above represent the average geometric and arithmetic rates of return over these 5,000 simulations. As the model produces 100,000 total annual rates of returns, it is not possible to provide full details on the formulas or results of the model.

For an example of determining the formulas for arithmetic mean and geometric mean, consider the following:

- A series of annual rates of return over "n" years, denoted as R1, R2 … Rn.
- The geometric return is determined as: {(1+ R1) x (1 + R2) … x (1 + Rn)}(1/n) – 1
- The arithmetic mean is determined as: (R1 + R2 … + Rn) / n
- For example, if "n" was 5 and the annual returns were 7%, 26%, -14%, 33% and -9%
- The geometric return = (1.07 x 1.26 x 0.86 x 1.33 x 0.91)(1/5) – 1 = approximately 7.0%
- The arithmetic mean = (7% + 26% - 14% + 33% - 9%) / 5 = approximately 9.0%

There are various formulae that can be used to estimate the difference between a geometric rate of return and an arithmetic rate of return. One approximation that was used in the determination of the Towers Watson's forecasted Canadian equities return is as follows:

- Arithmetic rate of return = Geometric rate of return + (annual standard deviation)2 / 2

In Towers Watson's model, the standard deviation assumption for rates of return on Canadian equities was approximately 19%. Therefore, the above formula produces the following relationship:

- Arithmetic rate of return = geometric rate of return + (0.19^2) / 2
- Arithmetic rate of return = 7.0% per year + 1.81% per year = 8.81%, which rounded to approximately 9% per year

This provides a comfort level that the geometric and arithmetic returns produced by the model are consistent.

47.4 Please confirm that AonHewitt appears to expect, over the next ten years, a geometric return on Canadian equities of 6.8 percent and an arithmetic average return on Canadian equites of 8.0 percent.

Response:

Confirmed that Aon Hewitt Canada's 10-year forward-looking capital market return assumptions for Canadian equities was 8.0% per annum on an arithmetic average basis and 6.8% on an annualized geometric basis.

47.5 FEI stated in response to BCUC IR 3.2 that the expected long-term equity returns derived by actuarial firms are comprised of a diversified asset portfolio for which forecast returns are not comparable in risk to a single, specific utility. FEI further states that these forecasted equity returns are based on a portfolio of different companies and different industries that have varying risks. In FEI's opinion, are utilities included in investors' portfolios in order to reduce investment risk or are utilities included in investors' portfolios in order to maximize rates of return?

Response:

There are a variety of reasons as to why an investor may include utilities in their portfolio. Depending on the composition of the rest of the portfolio, utilities may be included for both risk reduction and return enhancement reasons as the portfolio becomes more diversified.

Pension plan investment objectives will often include obtaining the highest return per unit of risk. In other words, reducing investment risk through diversification and maximizing rates of return. Therefore pension plan investors will include utilities, along with an entire spectrum of companies from other sectors and industries, in a diversified asset portfolio because all of those companies do not have the same risks, nor do they have correlated return expectations as their performance will vary in different market conditions. The idea is that specific company risk, such as that of a single, specific utility company, cannot be reduced on a stand-alone basis, but that risk can be lowered by holding a diverse portfolio of investments.

48.0 Reference: Exhibit B-9, BCUC IR 3.2; Exhibit A2-2, Morningstar Factsheet

Investment objectives and fair return

In response to BCUC IR 3.2, FEI stated that it is reasonable that the return for investing in a single utility will be higher than the asset return forecasted by actuarial firms on a portfolio of equity investments.

48.1 Morningstar Stock Sector Structure factsheet (Exhibit A2-2) describes the Australian sharemarket as consisting of three "Super Sectors": Cyclical, Defensive and Sensitive. The Defensive Sector in turns has three sectors: Consumer, Defensive Healthcare and Utilities. Does FEI agree with this classification for the North American sharemarket? If not, please explain why not.

Response:

FEI has asked Mr. Coyne to respond to this question.

Yes. Utility shares are often designated as defensive stocks, referring to their general characteristic of dividend and earnings stability. As mentioned in the Morningstar citation, stocks from the defense and consumer goods sectors are also considered defensive. It should be noted that the classification as "defensive" does not mean protected from the broad swings in market valuations or defensive in all environments. Fluctuations in interest rates and other factors that have a more pronounced impact on utilities can cause utility stock prices to deviate from broader market trends. Exhibit JMC-2 (Coyne Direct) shows that the S&P Utilities index has both under and out-performed the broader market in certain periods. This is further illustrated in the chart below.

Source: S&P Dow Jones Indices, McGraw Hill Financial

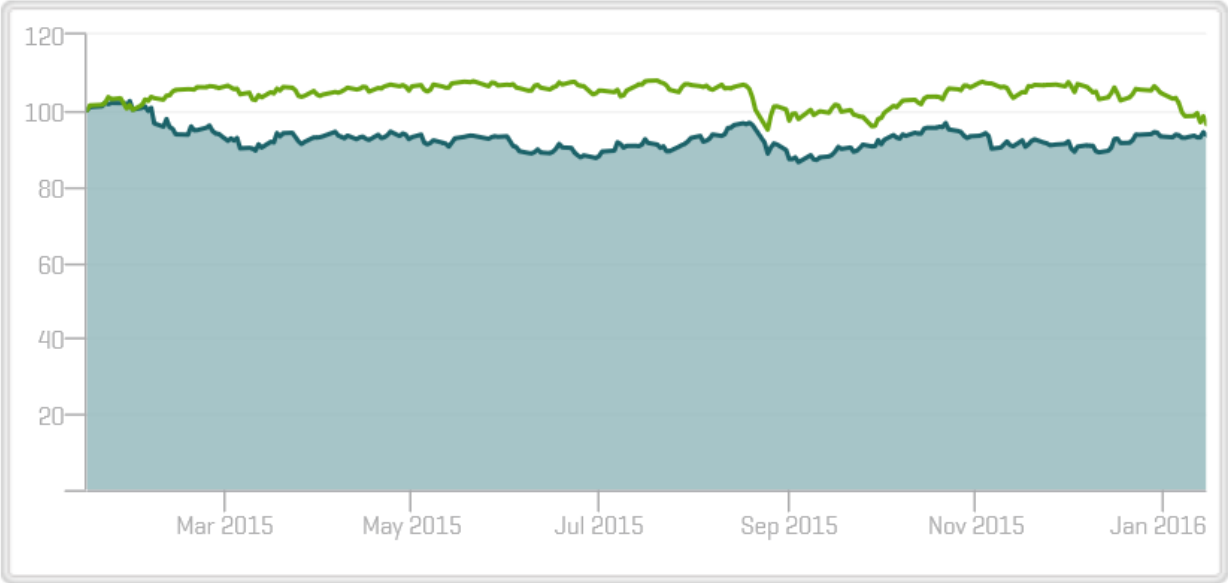
48.1.1 If the investment in Utilities equities can be described as Defensive, then does FEI agree that during recession, utilities stock tend to perform better than the market and during expansionary phase it performs below the market?

Response:

FEI has asked Mr. Coyne to respond to this question.

This is the case slightly more than half of the time. If Mr. Coyne accepts the premise of this question, we would expect to see utility returns exceed broader market returns in recessionary weeks. If we set aside weeks identified as recession, (Mr. Coyne has identified 174 recessionary weeks from January 1, 1988 to January 8, 2016),[1] the Canadian utility index outperformed the broader market 97 times, or approximately 55% of the time. Similarly, out of the 1,288 non-recessionary (or expansionary) weeks, the Canadian utility index under-performed the broader index in 677 weeks or approximately 53% of the time. Turning to the last 12 months of U.S. data, as illustrated below, measuring the performance of the S&P 500 Utilities Index against the broader S&P 500 market index shows that over the past year, the utilities and broader market were both affected by market volatility, but the utilities underperformed the broader market.

[1] According to the C.D. Howe Institute, in a study titled *Turning Points: Business Cycles in Canada since 1926*, which detailed among other things recessions that occurred in Canada between 1926 and 2012, the study identified relatively recent recessions as occurring between the months of March 1990 and April 1992; and from October 2008 to May 2009. In addition, Canada was in recession during the first two quarters of 2015 as indicated by two consecutive quarters of contraction as measured by GDP growth.



AS OF JAN 15, 2016

SPICE® SUBSCRIBERS EXPORT

Index Name	Index Level	1 Yr Ann. Returns
S&P 500 Utilities (Sector) (TR) LAUNCH DATE: JUN 28, 1996	524.46	-6.54 % ▼
S&P 500 (TR) LAUNCH DATE: MAR 04, 1957	3,518.51	-3.62 % ▼

Source: S&P Dow Jones Indices, McGraw Hill Financial

Further a regression of weekly S&P/TSX utility index returns against the broader S&P/TSX market, and setting aside the 174 recessionary weeks in the sample with a dummy variable, the regression coefficients indicate that there is no meaningful change in utility stock behavior during recessionary times, relative to the broader market. This is indicated by the low t-statistic for the "dummy recession" variable of -0.48. Regression results are shown below.

SUMMARY OUTPUT								
Regression Statistics								
Multiple R	0.507325301							
R Square	0.257378961							
Adjusted R Square	0.256360975							
Standard Error	0.018826136							
Observations	1462							
ANOVA								
	df	*SS*	*MS*	*F*	*Significance F*			
Regression	2	0.179218768	0.089609384	252.8314476	5.30528E-95			
Residual	1459	0.517103757	0.000354423					
Total	1461	0.696322525						
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.000687919	0.000525653	1.30869549	0.190843621	-0.000343196	0.001719035	-0.000343196	0.001719035
S&P/TSX Utilities I	0.589086655	0.026253047	22.43879144	4.87724E-96	0.537588908	0.640584402	0.537588908	0.640584402
Recession Dummy	-0.000732868	0.001522032	-0.481506277	0.630228929	-0.003718472	0.002252736	-0.003718472	0.002252736

In sum, even though utility stocks are considered defensive, there is not compelling evidence that utility stocks outperform the market during recessionary periods, and vice versa. Further, the returns from the broader market are not indicative of the required returns for utility investments. The preferred method for estimating required returns is the use of standard models, such as the DCF or CAPM, utilizing market inputs with consideration of the actual risk profiles of the target utility.

48.1.1.1 Does FEI agree that the betas of defensive stocks are less than one?

Response:

FEI asked Mr. Coyne to respond to this question.

Yes. Defensive stock betas would generally be less than one.

48.1.2 Please confirm that FEI's expert witness, Mr. Coyne, considers that the Canadian economy was in an expansionary cycle in the last quarter of 2015 and is expected to remain so.[2]

[2] See also BCUC IR 1.34.2.

Response:

Confirmed, though Mr. Coyne did note in his responses to BCUC IRs 1.34.1 and 1.34.2, that factors such as the significant decline in oil prices, have hampered the expansion of the Canadian economy. Mr. Coyne characterized the outlook as mixed, even though the Canadian economy returned to positive growth in the 3rd quarter of 2015, and projected by the Bank of Canada to remain in an expansionary cycle through 2017.

49.0 Reference: Exhibit B-9, BCUC IR 3.2

Expected returns on equity

FEI states that: "FEI continues to be subject to specific company risk which cannot be eliminated on a stand-alone basis. Accordingly, it is reasonable that the return for investing in a single utility will be higher than the asset return forecasted by actuarial firms on a portfolio of equity investments."

49.1 Please elaborate if it is FEI's view that, due to FEI's company-specific risks, it should be awarded an ROE that is higher than the expected ROE on a portfolio such as the market index?

Response:

Not necessarily. FEI's statement in the referenced excerpt that it believes that "the return for investing in a single utility will be higher than the asset return forecasted by actuarial firms on a portfolio of equity investments" was made in the context of a discussion of expected pension returns produced by actuarial studies. Such pension returns are not comparable to the returns of the regulated utility.

FEI has asked Mr. Coyne to also respond to this question.

Mr. Coyne agrees with the response above. The use of pension plan returns to inform an estimate on the utility investors' required equity return is inappropriate for several reasons. Pension returns reported by actuarial companies focus on expected or forecast returns and not on the required return or hurdle rate that investors use to determine whether the investment will provide fair compensation for the risks taken. There is a crucial distinction between expected and required return; that is, the expectation that an asset will return a given amount is fundamentally different than the return required by investors to take on the risks associated with the investment. Expected returns are forecasts of future performance, whereas required returns represent an opportunity cost, and are equal to the returns investors require in order to be compensated to take on the risks of ownership. Mr. Coyne would agree with the following comments published in the Wall Street Journal, which provides a concise synopsis of this distinction.

> There are two major drivers of investors' required returns—the perceived level of risk of the investment and alternative investment opportunities. Since most rational investors are risk averse, if there are two potential investments with the same expected return, but one is presumed to be riskier, then no one will invest in the riskier of the two. In order for the riskier investment to attract capital, it will have to provide a higher return. And the level of that return will be a spread relative to other investment opportunities. If the returns of other investments are meager, then the required return of the riskier investment will be less than if those other investments provided robust returns.

> So we should not talk about the expected return of stocks. We should talk about the required return. And, to reiterate, that required return is a function of the perceived risk and other investment opportunities.[3]

A pension fund asset manager will match the expected returns available from various asset classes to the expected liabilities that must be funded, while an investor seeking to maximize risk-adjusted return will only invest in a security if the expected return is equal to or greater than the required return from that investment. The distinction between expected and required returns, and the time horizon of the liabilities being funded by pension assets, was noted by the Arkansas Public Service Commission ("APSC") in Docket No. 04-121-U. In its decision, the APSC commented on the Attorney General witness' position that expected returns disclosed in the context of pension fund assumptions could be used in determining the ROE for a regulated utility as follows:

> There are two major problems with this sort of analysis: (1) it is unclear how long the time horizon is; and (2) these returns are expected, not required. It is well-established that expected returns may be less than, equal to, or greater than required returns. For that reason, expected returns cannot be used directly as a proxy for required returns, which is the information sought in a general rate case.[4]

Though ROE is established for a stand-alone company, the estimated return is derived from a market test of companies with comparable risks. The market tests in themselves assume a certain level of diversification. To determine the estimated return of a utility one must look to like-risk companies and not to a portfolio of assets that bear no resemblance to those of the utility. The market index, comprised of companies that span the entire risk spectrum, would not be an appropriate comparator or basis upon which to estimate the required return of a regulated utility. Return expectations for a portfolio of pension fund equity assets would similarly be an inappropriate comparator, as a typical pension fund includes a mix of equity securities and would not represent the investment or risk profile of a specific utility.

49.2 Is it FEI's view that the ROE should be awarded at a level sufficient to compensate a non-diversified equity investor as opposed to a diversified equity investor?

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[3] *Why Investors Need to Understand 'Required' Returns v. 'Expected' Returns,* Wall Street Journal ,Gus Sauter, (November 9, 2015) http://blogs.wsj.com/experts/2015/11/09/why-investors-need-to-understand-required-returns-vs-expected-returns/.

4 Docket No. 04-121-U, Order No. 16, APSC, September 19, 2005, at 19.

Response:

It is FEI's view that investors need to be compensated for FEI's specific risks, in such a manner as analyzed by Mr. Coyne, in order to meet the three requirements of the fair return standard.

49.3 Is it Mr. Coyne's view that the ROE should be awarded at a level sufficient to compensate a non-diversified equity investor as opposed to a diversified equity investor?

Response:

No. That is not Mr. Coyne's view. Please refer to Mr. Coyne's response to BCUC IR 2.49.4 which follows.

49.4 In the view of Mr. Coyne, do the Capital Asset Pricing Mechanism (CAPM) and Discounted Cash Flow (DCF) methods (as traditionally applied in Canadian utility regulation) produce ROEs that are reflective of the returns required by diversified investors as opposed to non-diversified equity investors?

Response:

Yes. Mr. Coyne agrees that the premise of the CAPM and DCF methods is that both methodologies produce returns that are reflective of the returns required by investors. Both methods assume at least some level of diversification. These assumptions are explicit in the CAPM model in that the model adds only the risk that cannot be diversified away to the required return. This simplifying assumption is a common critique leveled against the CAPM since it assumes that all investors mitigate all diversifiable risks and require compensation only for non-diversifiable risk. The DCF model derives a required return based on equity valuations and by association incorporates the premise that equity valuations incorporate all known information such that investors will always trade stocks at the "fair" value, i.e. stocks can be neither undervalued nor overvalued. The DCF model does not explicitly assume that investors mitigate all diversifiable risks, but does assume that markets are efficient and sophisticated investors act reasonably in response to information available in the marketplace. Both models assume that investors are knowledgeable and are able to diversify their risk.

These tools allow us estimate the cost of equity of a non-publicly traded entity by finding a proxy group of similar-risk companies and by observing the market behavior of sophisticated (and at least to some extent diversified) investors and the associated impact on its stock valuations and returns. Since both methods of ROE analysis have their own set of simplifying assumptions and shortcomings, employing both methods in an ROE analysis allows for some moderation of these assumptions and ultimately provides a more robust analysis.

50.0 Reference: Exhibit B-9, BCUC IR 4.1, 4.3 and 11.3

Short and long-term risks of FEI

Mr. Coyne defines short-term risks as those that will reverse or resolve themselves within a year or two, either through regulatory relief or normal ebb and flow of earnings, and long-term risks as those that relate to a shift in the business profile of the company for which there is no foreseeable mitigation.

FEI states that its overall business risk factors are similar to the risk factors presented in the British Columbia Utilities Commission Generic Cost of Capital (GCOC) Stage 1 proceeding; however, it assesses political risk to be higher than the 2012 level. It provides examples of the provincial government's environmental and climate change plans and municipal policies.

FEI also indicates that it is currently in a high capital growth period, driven primarily by a number of large projects.

50.1 Please comment on the drivers of the high capital growth in light of the recent historical growth in new customer additions and sales/transport volumes shown in the Table in response to BCUC IR 1.1.

Response:

As shown in the response to BCUC IR 1.1.1, FEI's historical growth in total net customer additions has ranged from negative 1% to positive 2% over the past ten years. More recently, over the past five years, customer growth has averaged 0.6%. Sales and transport volumes have been variable, declining some years and increasing in others, with an average growth over the past five years of 0.8%. However, neither the general trend in customer growth or in volumes is driving the high capital growth currently being experienced and referred to in the preamble. Instead, the growth in capital is being driven by a number of large capital projects with specific drivers as described below. These are the same projects that were listed in the response to BCUC IR 1.11.3.

Coastal Transmission System (CTS)

The CTS projects consist of four transmission line projects, three of which increase the Company's pipeline capacity within the Lower Mainland (Cape Horn to Coquitlam, Nichol to Port Mann, Nichol to Roebuck) and one (Tilbury Valve Station to LNG Plant) increases the capacity to the Company's Tilbury LNG Facility. The projects are intended to increase security of supply by reducing the number of single points of failure and accommodate increased transmission system throughput for deliveries to LNG facilities in the Lower Mainland (Tilbury and Woodfibre).

Lower Mainland Intermediate Pressure System Upgrade (LMIPSU)

The LMIPSU is an integrity project to address an increasing number of gas leaks on the Coquitlam IP line and seismic upgrades required to the Fraser Gate IP line. It will replace approximately 20 km of existing 1200 kPa Nominal Pipe Size (NPS) 20 intermediate (IP) pipeline between Coquitlam Gate Station in Coquitlam and the East 2nd & Woodland Station in Vancouver with a 2070 kPa NPS 30 pipeline (Coquitlam IP) and also to replace a 0.5 km section of the existing 1200 kPa NPS 30 IP pipeline between Fraser Gate Station and East Kent & Elliot Street in Vancouver with a 1200 kPa NPS 30 IP pipeline (Fraser IP).

Tilbury Expansion Project – Phase 1A

The Tilbury LNG Expansion Phase 1A project is to expand the existing Tilbury LNG Facility at Tilbury Island in Delta, BC. The facility will produce LNG primarily for the transportation fuel supply market, providing new production capacity of approximately 34,000 GJ/day and a new storage tank with a capacity of approximately 1.1 PJ of LNG.

Eagle Mountain Gas Pipeline

This project consists of pipeline looping and compression upgrades of FEI's high pressure transmission system that serves the Sunshine Coast and Vancouver Island including Whistler and Squamish. The expansion is needed to provide natural gas transportation service to the proposed small scale LNG facility to be owned, constructed and operated by Woodfibre LNG (WLNG) on a former pulp mill site near Squamish.

Tilbury Expansion Project – Phase 1B

As mentioned in the response to BCUC IR 1.11.3, FEI has conditional approval for this project. This approval is based on attracting one or more large customers to employ 70% on average of the installed liquefaction capacity for the project for a period of at least 15 years. The specific project configuration and costs will vary based on how and when these conditions are met.

50.2 Given the long term political risk articulated by FEI with regards to government policy recommendations that could significantly affect FEI's competitiveness, Use per Customer (UPC), throughput, capture rate and in general the long-term viability of its traditional markets, please explain FEI's forecast high growth in capital spending.

Response:

FEI has explained the drivers and the specific projects behind the growth in capital spending in the response to BCUC IR 2.50.1. These drivers and the related projects are generally independent of the factors listed in the question, with some projects contributing to higher rates for customers.

The Lower Mainland Intermediate Pressure System Upgrade project is required to maintain the integrity of the Coquitlam IP line and address seismic concerns at the Fraser Gate IP line. The need for the project is in general not affected by the factors listed in the question. Similarly, the Coastal Transmission System projects are required to increase security of supply by reducing the number of single points of failure and to accommodate increases in throughput arising from LNG developments in the Lower Mainland. These large projects are needed primarily to continue to operate the gas system in a safe and reliable manner and they have the effect, other things being equal, of increasing rates for customers.

The Tilbury Expansion and Eagle Mountain projects are required to specifically service the developing LNG markets. The Eagle Mountain project, in particular, will only be constructed if the WLNG facility proceeds and has contracted for transmission service on FEI's system under the terms and conditions of Rate Schedule 50. Other things being equal, both projects are expected to result in greater use of the gas system and have a favourable impact on the rates of other customers over time.

FEI continues to work to find solutions that will help with challenges it faces in retaining and adding customers and increasing throughput.

51.0 Reference: Exhibit B-9, BCUC IR 4.3 and 11.3

FEI business risk

In response to BCUC IR 4.3, FEI stated:

> … recent developments in local governments' policies in promoting mandatory connections, the political risk category may face a significant incremental (i.e., steeper) upward trend from developments that are not yet fully realized. The BC provincial government's environmental and climate change policies are similar to the ones that existed during the GCOC proceeding; however… the BC government is in the midst of developing a new 'climate leadership plan' to review the options available for reinforcing the provincial efforts to reduce GHG emissions and has created a 'Climate Leadership Team' to provide advice and recommendations to government on a new Climate Action Plan. This team has recently published a series of recommendations to the government that, if accepted, can significantly affect FEI's competitiveness, UPC, throughput, capture rate and in general the long-term viability of its traditional markets.

In response to BCUC IR 11.3, FEI stated:

> FEI is currently in a high capital growth period, driven primarily by a number of large projects, each at various stages of consideration, approval, development or construction… The timing of expenditures and the approval of certain of the projects over the 2016-2018 time period is uncertain, but for purposes of ensuring access to capital as it relates to the Company's Trust Indenture coverage test, FEI has considered the financing requirements of all of the projects during this time period.

FEI listed the Lower Mainland Intermediate Pressure System Upgrade, Coastal Transmission Projects, Tilbury 1A, Woodfibre and Tilbury 1B projects as approved and potential capital projects during the above noted time period. The expected capital expenditures in 2016 of $130 million will increase to $730 million in 2018.

51.1 As indicated in BCUC IR 4.3, the government has not set any policies regarding the Climate Leadership Team's recommendations. In light of the fair return standard, should the Commission give less, equal, or more weight to unrealized risks vs. events that are realized?

Response:

The business risk assessment routinely employed in setting a utility return inherently requires consideration of uncertain events that have not yet materialized. Since the determination of cost of capital is a forward-looking process, it is appropriate to consider the potential unrealized

events that may impact investors' decision making and required return. The weight that is given to each event should depend on the status of the developments related to that event and/or the probability of the event occurring, and the magnitude of the impact if it materializes.

With respect to the specific issue of BC provincial government's Climate Leadership Plan, BC government has not finalized any policies yet. As mentioned in the preamble, the recommendations of the climate leadership team (whose mandate was set by the BC government) were only recently released and are yet to be adopted by the government. Other things being equal, FEI would expect that the recommendations would have greater weight in an investor's deliberations if they were adopted and implemented as well. Nevertheless, these recommendations create significant additional uncertainty around the potential future political risk for investors and at minimum reinforce and amplify the direction of the provincial government in its policies that are generally less favourable to natural gas in traditional applications. The potential introduction of these policies and other actions by municipal governments signify a greater risk than in the past, and a potentially larger impact to investors from these initiatives. Therefore it is appropriate for the Commission to consider this additional uncertainty in its risk evaluation. FEI expects that it would require a far greater return than it is seeking in this Application if all of these recommendations in the Climate Leadership Plan were already approved and being implemented. For a list of recommendations please refer to BCUC IR 1.4.3.

51.2 As indicated in BCUC IR 11.3, FEI will build major projects in the next few years. Does FEI agree that these projects will offset the potential unfavourable risks in traditional markets influenced by Government policies as indicated in BCUC IR 1.4.3?

Response:

Although FEI does expect net benefits for conventional natural gas rate payers from the throughput related to some of the major projects such as Tilbury 1A, 1B and EGP (Woodfibre), these benefits will provide only partial mitigation of the potential unfavourable risks in traditional markets. Please refer to BCUC IR 1.21.3 and CEC IR 1.16.3.1 for discussion of the potential benefits attached to these large projects and the likelihood of their occurrence. As noted in the response to BCUC IR 2.50.2, other major projects, such as the LMIPSU project, are mainly related to system integrity and reliability and, other things equal, will cause rate increases for conventional natural gas customers. Large projects of this nature, although they are necessary, will tend to contribute to rate pressure and impact competiveness. .

51.3 Please confirm that the Coastal Transmission Projects, Woodfibre, Tilbury 1A and 1B are exempt from Commission regulatory review in accordance with Order in Council 749, deposited December 22, 2014.[5] If not confirmed, please clarify.

Response:

Order in Council (OIC) 749, deposited December 22, 2014, contained a series of amendments to Direction No. 5 to the Commission, which was initially enacted on Nov 27, 2013 by OIC 557. Subject to certain conditions, Direction No. 5 (as amended by OIC 749) provides exemptions from the requirement for FEI to obtain CPCNs from the Commission for the projects identified in the question.

51.3.1 Since these projects are exempt from Commission regulatory review, please describe the steps that FEI has taken to ensure the company has adequate access to capital.

Response:

The CTS, EGP (Woodfibre) and Tilbury Phase 1A and 1B were exempt from a regulatory review process by government issued Order-in-Council (OIC). Similar to a CPCN proceeding, an OIC assumes that the Commission will provide the utility with a fair allowed ROE and equity thickness to ensure adequate access to capital (the issue of access to capital is not separately considered in CPCNs or OICs). The invested capital for these projects will be placed in FEI's regulated asset base and subject to FEI's normal financing requirements.

In order to ensure adequate access to capital to finance these significant capital projects, FEI has taken the step of requesting a 40% equity thickness and 9.50% allowed ROE as part of this Application. Another step taken by FEI to ensure adequate and timely access to public debt in order to finance the significant capital expenditures was the establishment of a $1 billion Medium Term Note debenture shelf prospectus program which was approved pursuant to Commission Order G-37-15 in March 2015 and is effective to May 2017.

[5] http://www.bcuc.com/Documents/SpecialDirections/2014/12-19-2014_OIC749-Amendment-Dir5BCReg245-2013.pdf

51.3.2 Please describe the subject approvals required for the Woodfibre and Tilbury 1B projects. What is the likelihood that all of the major projects listed will move forward?

Response:

In order for the Eagle Mountain to Woodfibre Gas Pipeline (EGP) project to proceed, WLNG must have made a final decision to proceed with the construction of their LNG facility and have contracted under FEI's Rate Schedule (RS) 50 for delivery of the natural gas to their facility for conversion to LNG. RS 50 requires customers to sign up for a term of 15 years or more and a minimum contract demand of 45 TJ/day. In addition, WLNG will have to provide security as required by the RS 50 tariff to mitigate potential losses from a customer default or non-payment under the contract. There are a number of other external approvals that the EGP project must obtain before it can proceed, such as those required by the Oil and Gas Commission (OGC) and federal and provincial environmental certificates. As with all major projects, internal board approval will also be required for the project to go ahead.

The Phase 1B expansion of the Tilbury LNG facility can proceed without a Commission regulatory review, subject to meeting certain conditions set out in Direction No. 5 to the BCUC. The Phase 1B expansion is intended to consist primarily of additional liquefaction facilities and cannot, according to Direction No. 5, include an LNG storage tank. The second condition imposed by Direction No. 5 is that FEI must have entered into one or more long term contracts with customers that use (on average) at least 70% of the Phase 1B liquefaction capacity over the first 15 years that the Phase 1B facilities are in service. External approvals by the OGC and others will be required, but the specific approvals will not be known until the project configuration is finalized. As noted for the EGP project, internal board approval will also be required for the project to go ahead.

The major projects listed, other than the Tilbury Phase 1B and EGP projects, are likely to go ahead, and project planning and development is already underway. Tilbury Phase 1B and EGP are both contingent on customer contracts being in place, as described in the preceding paragraphs, so they will be supported by significant revenue streams from those contracts if they do go ahead. There is less certainty, however, that these projects will proceed.

52.0 Reference: Exhibit B-9, BCUC IR 10.1; Exhibit B-1, Application, Table 4, p. 26

Credit metrics of sample Canadian utilities

BCUC IR No. 1 referenced Table 4 in the Application and requested the addition of CU Inc. and Fortis Inc. to the table and further requested a summary of the range of credit metric, equity ratios and allowed ROEs that were associated with a credit rating of A (low). FEI provided data for CU Inc. and Fortis Inc. but noted that these are holding companies that do not have an allowed ROE or equity thickness.

52.1 Please add the actual ROE and the actual equity thickness for Fortis Inc. and CU Inc. to the information that was provided in response to BCUC IR 10.1.

Response:

FEI has included the actual ROE and equity thickness of Fortis Inc. and CU Inc. in the table below. Fortis Inc.'s actual ROE and equity percentage have been determined from figures presented in its most recent S&P credit rating report, and are therefore subject to any customary adjustments that S&P requires. Similarly, all actual results for CU Inc, have been obtained from its recent DBRS rating report, and are therefore subject to their required adjustments.

		EBIT Interest Coverage			Debt to Total Capital			ROE			Equity Percentage		
Fiscal Year	**DBRS Rating**	12 x	13 x	14 x	12 %	13 %	14 %	12 %	13 %	14 %	12 %	13 %	14 %
CU Inc.[1, 3]	A (high)	2.7x	2.7x	2.67x	57.1%	57.7%	60.2%	10.1%	10.0%	10.5%	43.7%	42.8%	40.1%
Fortis Inc.[2,4]	A (low)	2.17x	2.19x	1.91x	56.5%	56.5%	61.7%	7.4%	6.9%	5.5%	41.1%	40.9%	39.9%

1 - Metrics are labelled as EBIT Gross Interest Coverage (times) and total debt in capital structure per the CU Inc. ratings report.

2 - All 2014 metrics are reported for 12 months ended September 30, 2014 due to timing of the report production, where as all other years are as at December 31. Also noted that the figures provided represent the consolidated metrics as per the most recent DBRS rating report.

3 -ROE and Equity Percentage for CU Inc have been obtained from most recent DBRS report. Equity percentage includes preferred shares.

4 -ROE and Equity Percentage for Fortis Inc have been obtained from most recent S&P report. Equity percentage includes preferred shares.

52.2 Based on the information in Table 4 and the additional information for Fortis Inc. and CU Inc., please provide a summary of the range of credit metrics, allowed equity ratios and equity thickness that were associated with a Dominion Bond Rating Services (DBRS) credit rating of at least A (low). Please use the actual equity ratio and equity thickness for CU Inc. and Fortis Inc.

Response:

The table below reflects the range of credit metrics, ROE and equity thickness for all entities with at least an A (low) rating included in Table 4 of the Application. FEI has excluded the credit metrics, actual equity thickness and ROE of CU Inc. and Fortis Inc., as provided in the response to BCUC IR 2.52.1, from this table because CU Inc. and Fortis Inc. are parent holding companies for regulated utilities and operate in various market areas and in several different jurisdictions. Therefore FEI does not believe that it is appropriate to compare the credit metrics, actual ROE, and equity thickness of these companies to that of Canadian regulated utilities.

For further context however, CU Inc.'s credit metrics, ROE and equity thickness would all fall within the ranges noted below. Fortis Inc.'s credit metrics and equity thickness would also fall within these ranges; however its actual ROE would fall below this range for the last 3 years. For further discussion around the lower actual ROE of Fortis Inc. during this period, please refer to BCUC IR 1.12.1.

	EBIT Interest Coverage			Debt to Total Capital			ROE			Equity Thickness		
Fiscal Year	12	13	14	12	13	14	12	13	14	12	13	14
	x	x	x	%	%	%	%	%	%	%	%	%
Max	2.9	3.0	3.1	64.2	65.3	67.9	11.5	11.5	11.5	45.0	45.0	45.0
Min	2.0	1.8	1.9	51.7	53.9	52.9	8.1	8.3	8.3	36.0	36.0	36.0

52.3 Please provide similar information based on Standard & Poor's (S&P) credit ratings, if available.

Response:

FEI does not have access to the requested specific credit metric information for companies rated by S&P. However, FEI notes that a recent S&P rating report for Fortis Inc. includes a table of financial data and credit metrics for comparative A rated Canadian utilities that may have relevance to this question.

The financial information below reflects the average of the past three fiscal years. Using the data available through this particular S&P rating report, FEI has compiled the table below which reflects similar credit metrics to those included in Table 4 of the Application.

		EBITDA Interest Coverage	Debt to Debt & Equity
Fiscal Year[1]	**S&P Rating**	3 Year Average x	3 Year Average %
Fortis Inc	**A-**	3	60
Hydro One Inc.	**A**	3.6	61
CU Inc.	**A**	3.5	61
ATCO Ltd.	**A**	4.3	59
Max		4.3	61
Min		3.0	59

1 - Fortis Inc. S&P rating reports notes that these financial metrics and ratios are average of the past 3 fiscal years.

53.0 Reference: Exhibit B-9, BCUC IR 34.2 to 34.3, 36.1 and 36.2;

Exhibit B-1, Application, Appendix B, Evidence of Mr. James Coyne, Exhibit JMC-2

Interdependent economies of US and Canada

In his response to BCUC IR 34.3, Mr. Coyne opines that the Canadian and US economies are moving relatively in sync and remain closely interdependent.

53.1 The tables in response to BCUC IR 36.1 and IR 36.2 show that while the Canadian utilities have at least 20 percent non-Canadian ownership (except Canadian Utilities Ltd.) with US being dominant, the US proxy companies each have less than 1 percent Canadian ownership. Would it be more apt to describe that the Canadian economy is dependent on US but not vice versa and that "interdependency" is actually a one-way dependency?

Response:

As Mr. Coyne indicated in his responses to BCUC IR 1.36.1 and BCUC IR 1.36.2, the tables, referenced in this interrogatory included only institutional investors and insiders. To Mr. Coyne's knowledge, information on the share of domestic stocks owned by foreign individuals is not available in the public domain. If it is assumed that foreign institutional ownership percentages are representative of foreign ownership in domestic stocks in general, the differences in ownership between the U.S. proxy group and the Canadian proxy group may be explained by a number of factors.

First, the referenced Canadian proxy group companies have made significant acquisitions of publicly-traded U.S. utilities. Some shareholders of the acquired U.S. companies may have re-invested their proceeds in the Canadian shares of the acquiring companies.

Secondly, the U.S. stock market is of a much larger scale than the Canadian stock market in terms of market capitalization, listed members, and opportunities for investment both domestic and abroad. According to the World Federation of Exchanges, the market capitalization of U.S. exchanges (approximately $26 trillion for the NYSE and the NASDAQ) dwarfs the size of the Canadian TMX Group market of approximately $1.7 trillion by a multiple of 15x. Further, the U.S. stock markets list approximately 5,441 companies, while the TMX Group lists 3,518 domestic companies. The U.S. stock markets list 904 foreign companies while the Canadian TMX Group lists only 58 foreign companies. This suggests a U.S. investor seeking to invest in Canada will have a more concentrated exposure to fewer companies, and Canadian investors seeking to invest in the U.S. will have a broader array of options. Notwithstanding, Canada and the U.S. economies are indeed interdependent and the two countries' economies are inextricably linked. According to the U.S. State Department:

> Canada and the United States have one of the world's largest investment relationships. The United States is Canada's largest foreign investor, and Canada is the third-largest foreign investor in the United States. U.S. investment is primarily in Canada's mining and smelting industries, petroleum, chemicals, the manufacture of machinery and transportation equipment, and finance. Canadian investment in the United States is concentrated in finance and insurance, manufacturing, banking, information and retail trade, and other services.[6]

So, though U.S. investment in Canada has a relatively greater impact on the Canadian economy than does the impact of Canadian investment on the U.S. economy, this does not negate the interdependence of the two economies.

53.2 The US proxy companies were selected by Mr. Coyne because of their similar risk level to FEI's risk. Given the data on international (other than US or Canada residents) ownership in the tables in response to BCUC IR 36.1 and 36.2, is it reasonable to conclude that international investors have similar proportion of a utilities total level of investments in the US and Canada despite the higher allowed returns for US utilities?

Response:

Though the data in the referenced tables provided in response to BCUC IRs 1.36.1 and 1.36.2 is not complete for the reasons referenced in Mr. Coyne's response to BCUC IR 2.53.1 above, if we were to extrapolate the same share of country ownership to those not represented by the data, the result would suggest that utilities in both Canada and the U.S. attract a similar level of foreign (non-North American) investment.

> The table response to BCUC IR 36.1 shows that for the major Canadian proxy companies, the majority of investors are Canadian with the exception of Enbridge Inc. The table response to BCUC IR 36.2 shows that for the US proxy companies, overwhelming majority of investors are US residents.

[6] U.S. Department of State, Bilateral Relations Fact Sheets – Canada (August 5, 2015)

53.3 In FEI's view, is it reasonable to conclude from the information provided in the two tables that Canada is a more open economy than the US with respect to attracting foreign investors?

Response:

FEI has asked Mr. Coyne to respond to this question.

No, it is not reasonable to conclude from the referenced data that Canada is a more open economy. In Mr. Coyne's opinion, the differential is more due to the differences in scale between the U.S. market and the Canadian market. The U.S. investor market is roughly 15 times the size of the Canadian stock market, and lists a far greater number of foreign companies. Please also refer to Mr. Coyne's response to BCUC IR 2.53.1.

53.4 In FEI's view, is it reasonable to conclude that despite the higher allowed ROE and higher deemed equity component for the US proxy companies, the Canadian proxy companies still attract a sizeable share of US and international investors?

Response:

FEI has asked Mr. Coyne to also respond to this question.

It is reasonable to conclude that Canadian proxy companies are able to attract U.S. and international investment. It is important to note that those Canadian utilities that show a large share of U.S. stock ownership also have significant U.S. utility holdings in their corporate structures. Consequently it stands to reason that those utilities would be able to attract U.S. capital. Conversely, Canadian Utilities with no U.S. holdings has the lowest share of U.S. ownership.

53.5 In Exhibit JMC-2, Mr. Coyne provided the 5-year, 10-year and 25-year averages as well as correlation between US and Canada macroeconomic data to describe the similarity between US and Canadian economies and the degree of integration. Would Mr. Coyne please include in his response the following: (i) trade weighted index of the USD and CDN dollar; (ii) public debt to GDP ratio; (iii)

balance to his table in Exhibit JMC-2 of payments current account surplus/deficit; and (iv) federal budgets surplus/deficit.

Response:

Please refer to Attachment 53.5.

53.5.1 Please provide any further updates to the data contained in Exhibits JMC-2 and JMC-3 in the application.

Response:

Please refer to the response to BCUC IR 1.53.5.

54.0 Reference: Exhibit B-9, BCUC IR 42.2 and 42.3

Expected equity returns in Canada and the US

In his response to BCUC IR 42.2 and IR 42.3, Mr. Coyne takes the position that the market data supports the required return on equity markets as approximately 10 percent and 11.3 percent for Canada and US equity markets respectively.

Mr. Coyne further states that his overall market DCF calculation on the S&P/TSX Index shows that a return on the market of 13.48 percent is indicated by the underlying market data. For the US equity market, Mr. Coyne's overall market DCF calculation on the S&P 500 Index shows that a return on the market of 12.37 percent is indicated by the underlying market data.

In the 2012 GCOC proceeding, the expert witness for FEI Ms. McShane responded to a BCUC IR 62.1 (Exhibit B1-20 of the 2012 GCOC proceeding) related to market risk premium over bond returns. The response included stock returns based on geometric averages. The data from the response to IR is reproduced below:

62.1 Please provide a table showing risk premiums over Bond Total Returns and over Bond Income Returns, using geometric averages.

Response:

The table below shows the risk premiums over Bond Total Returns and over Bond Income Returns using geometric averages. As discussed in Appendix A of Ms. McShane's testimony, the arithmetic average, not the geometric average, should be used to estimate the expected equity market risk premium.

Period	Stock Returns	Bond Returns:		Risk Premium Over Bond:	
		Total Returns	Income Returns	Total Returns	Income Returns
Canada					
1924-2011	9.8	6.3	6	3.5	3.8
1947-2011	10.4	6.7	6.7	3.8	3.7
U.S.					
1926-2011	9.8	5.7	5.1	4.1	4.7
1947-2011	10.9	6.1	5.9	4.8	5

54.1 Please reconcile the stock returns in Ms. McShane's evidence with the expected returns on the market in Mr. Coyne's responses to BCUC IR 42.2 and IR 42.3

Response:

The stock and bond returns shown in the table above are historical returns using a geometric averaging convention. As indicated in Ms. McShane's response to IR 62.1, the geometric average is inappropriate when averaging independent return observations. As discussed on p. 46 of Mr. Coyne's Direct Testimony, the arithmetic mean is the relevant value for purposes of computing the market risk premium. A review of U.S. data from 1926-2014 reveals that the arithmetic mean stock return from 1926-2014 is 12.1%, the income return on long term government bonds is 5.1% and the resulting ex-post market risk premium is 7.0%. This is 1.9% above the market risk premium computed using the geometric mean as shown below:

Period 1926-2014 U.S. Data	Large Cap Total Stock Returns	Long Term Gov. Bond		Risk Premium Over Bond:	
		Total Returns	Income Returns	Total Returns	Income Returns
Arithmetic Mean	12.1	6.1	5.1	6.0	7.0
Geometric Mean	10.1	5.7	5.0	4.4	5.1
Difference	2.0	0.4	0.1	1.6	1.9

Source: Ibbotson SBBI 2015 Classic Yearbook at p. 91

The expected returns referenced in this question, refers to ex-ante or forward looking market returns derived through a market DCF calculation developed by Mr. Coyne in his Exhibit JMC-4. Mr. Coyne calculated market returns for Canada of 13.46% and for the U.S. of 12.37%. There is no direct link between the ex-post returns reported in the tables above and the ex-ante returns projected through a forward looking DCF analysis. The returns could differ significantly depending on anticipated future market conditions. The U.S. ex-ante return of 12.37% is surprisingly close to the ex-post market return using an arithmetic average, with a difference of only 27 basis points. This would suggest that the forward looking view of market conditions very closely approximates the long term historical market average. Mr. Coyne does not have comparable data for Canadian returns, but since we know that the Canadian historical market risk premium calculated with an arithmetic average was 5.6% in 2014, and Ms. McShane calculated the market risk premium in her table using a 2011 geometric mean of 3.8%, we find a similar differential between the market risk premium calculated using the arithmetic mean vs. the geometric mean, of roughly 1.8%. It can be safely assumed that converting the geometric means in Ms. McShane's table to arithmetic means, would add roughly 2% to the geometric average of the historical stock returns. This would result in 11.8% for Canada based on Ms. McShane's 1924-2011 stock returns.

55.0 Reference: Exhibit B-9, BCUC IR 33.1; Exhibit B-7, AMPC to FEI IR 2.13

Required returns by investors

Mr. Coyne had submitted in his testimony that "the assessment of whether the Fair Return Standard has been met requires an examination of the required returns by investors in like-risked enterprises." The response to BCUC IR 33.1 indicated that "Mr. Coyne had not carried out survey research on the required returns by investors in FEI-like enterprises, or lower/high risk enterprises in Canada, the U.S. or elsewhere, nor is he aware of survey information on required equity returns for utilities or companies of similar risk to FEI."

In response to AMPC to FEI IR 2.13, FEI provided the 2015 Fearless Forecast by Mercer dated January, 2015. Page 24 of the report lists the 46 investment management firms that participated. The highlights section of the Mercer report states:

> Managers expect public equity markets to post median returns (in C$) between 7.5%and 8.0% in 2015. Four year expectations for equities are also strong with a median four year forecast (in C$) of 7.0% for the S&P/TSX Composite Index, 7.2% for the MSCI ACWI Index and 7.3% for the S&P500 Index.

55.1 Please confirm that on page 3 Mercer describes the four year expected return of 7.0 percent to 7.3 percent as "strong".

Response:

Confirmed. However, the remarks must be read in the overall context of the narrative. In the next two paragraphs on Capital Markets, Mercer discusses fixed income returns between 0.9% and 2.4% depending on the index and period. Mercer may consider 7.0% and 7.3% as strong by comparison, but it is not clear what comparison is being made.

Please also refer to Mr. Coyne's response to BCUC IR 1.55.2.

55.2 Please explain the relationship between required returns and expected returns for securities.

Response:

FEI has asked Mr. Coyne to also respond to this question.

In the context of question 55.1, which describes Mercer's summary of managers' expected returns, versus the required returns of investors: expected returns are those projected by any host of organizations or individuals with a view of the market returns that may be realized for a given period. These expected returns may, or may not, meet the required returns of a given investor. If the expected return, when realized, falls short of the investor's required return, the investor has the choice of adjusting expectations, or moving that investment to a source that will meet the required return. Please also refer to Mr. Coyne's response to BCUC IR 2.49.1.

55.2.1 Please provide your response also in the context of the DCF test. Does the DCF test assume that the expected return is the required return?

Response:

The DCF model assumptions contain no explicit mention of expected returns, but the model is widely applied to estimate required returns. The underlying valuation theory behind the DCF model posits that the value of a share of common stock can be derived from the discount rate and the expected dividend stream. The model can be restated to determine the discount rate from the stock price and the dividend stream. The discount rate is assumed to represent the revealed cost of equity that equates that stock price with that expected dividend stream. Over time, one would rationally expect investors to move into or out of a given investment until the expected and required returns are in equilibrium, but this is not an explicit assumption of the model.

55.3 Please explain if the median expected four year forecast for the S&P/TSX composite index of 7.0 percent can be used as any indication of the median required return on Canadian equities by the survey participants.

Response:

As explained in response to BCUC IR 2.55.2 above, the expected returns may, or may not, meet the required returns of a given investor. Investors make ongoing judgements concerning their required returns in relation to the risk adjusted returns across a range of potential investments. Given the increasing volatility in global and North American markets since August 2015 and continuing into 2016, some investment advisors are recommending rotating out of equities and into less volatile cash or related securities. This suggests a view that equities may

not meet the risk adjusted required returns of investors in the current market environment. If so, we may see a sell-off in stocks until investors perceive a balance between their required and expected returns. So, one cannot assume the expected return cited in the question and report is equivalent to the required return of investors.

55.4 Is it reasonable to assume that the median expected and/or required return on Canadian utility equity by these survey participants would be somewhat lower than their expectations and/or requirements for the overall Canadian equity return?

Response:

As described in response to BCUC IRs 2.55.2 and 2.55.3, one cannot determine required returns from this report. Insofar as expected returns, page 19 of the Mercer report shows a collective expectation for utilities to have underperformed in 2015, but there is no longer term view expressed.

55.5 Please explain whether the Mercer survey forecast returns should be viewed as geometric returns or arithmetic returns or if it is not possible to categorize the forecasts in that way.

Response:

The report does not state whether the returns are geometric or arithmetic, but multi-year returns are typically expressed on a geometric basis, and these would be lower than an arithmetic average. The Hewitt report, for example, also attached to FEI's response to AMPC-FEI IR 1.2.13, contains both Arithmetic and Geometric averages (see page 18). The arithmetic averages for Canadian and U.S. equities are 1.2% and 1.0% higher, respectively, than the geometric returns.

56.0 Reference: Exhibit B-9, BCUC IR 44.2 and 44.3

Credit metric and credit rating

BCUC IR 44.2 had asked Mr. Coyne to confirm that at the end of 2014, Fortis Inc. had a goodwill asset of $3,732 million and total equity of $8,691 million and to comment if the existence of goodwill contributes to weaker credit metrics for Fortis Inc. than would otherwise be the case in the absence of goodwill. Mr. Coyne responded that it depended on several considerations including how the goodwill was financed and that assuming it was fully financed by equity, the existence of goodwill does not contribute to weaker credit metrics for Fortis Inc. and actually improves the debt to capital ratio while the cash flow metrics would be unaffected.

Could Mr. Coyne please respond to the following questions which refer to Fortis Inc.'s balance sheet as of December 31, 2014?

56.1 Please confirm that the total shareholder equity was $9,112 million including the non-controlling interests. If not confirmed, please provide the correct figure.

Response:

Confirmed.

56.2 Please confirm that Fortis Inc. had total debt of $330 + $505 + $9,996 = $10,831 million. If not confirmed, please provide the correct figure.

Response:

Confirmed.

56.3 Please confirm that the total shareholder equity plus debt totaled $19,943. If not confirmed, please provide the correct figure.

Response:

Confirmed.

56.4 Please confirm that the equity ratio was $9,112 / $19,943 = 45.7%. If not confirmed, please provide the correct figure.

Response:

Mr. Coyne can confirm that $9,112 - $3,732 = $5,380. However, this is not a ratio nor does it represent only tangible assets since Fortis Inc. also lists intangible assets of $488 on its balance sheet besides the goodwill.

56.5 Please confirm that the tangible equity ratio, after deducting goodwill, was $9,112 - $3,732 = $5,380 million. If not confirmed, please provide the correct figure.

Response:

Confirmed.

56.6 Please confirm that the tangible equity plus debt was $5,380 + $10,831 = $16,211 million.

Response:

Confirmed with the caveats noted in BCUC IR 2.56.5 above.

56.7 Please confirm that the tangible common equity ratio, after deducting goodwill was $5,380/16,211 = 33.2%. If not confirmed, please provide the correct figure.

Response:

Confirmed with the caveats noted in BCUC IR 2.56.5 above.

56.8 Please confirm that Mr. Coyne, at page 31 of his evidence described Fortis Inc. as being relatively pure-play with 93 percent of its assets dedicated to utility service.

Response:

Confirmed.

56.9 Please comment on the ability of Fortis Inc. as a relatively pure-play regulated utility to achieve an A range credit metric with a tangible equity ratio of 33.2% while Mr. Coyne supports a 40.0% equity ratio for FEI.

Response:

Mr. Coyne does not view the "tangible" equity ratio to be a relevant metric for his consideration. Intangible assets contribute to the ability to generate profit and should be considered in the equity of the firm. The company is prohibited by accounting and reporting regulations from carrying assets on its books that are unrepresentative of their value. The credit ratings agencies are expected to assess the risks they identify in a company's financials. The agencies review the company's financial information and make adjustments to the reported financial information they deem necessary to properly reflect the true nature of the accounts. In reviewing the most recent ratings reports for Fortis Inc., Mr. Coyne notes that neither S&P nor DBRS made adjustments to Fortis Inc.'s equity to remove goodwill or reported on tangible equity. Though adjustments were made to both debt and equity, the resulting equity ratios for 2014 were 37.4%[7] and 38.3%[8], respectively. Further, the most recent DBRS report shows Fortis Inc.'s equity ratio to be 41.8% for 2015.

[7] S&P Ratings Direct, Fortis Inc. (April 30, 2015) p. 5-6. Calculated by dividing equity of $8,202 by total capital of $21,929.1.

[8] DBRS Rating Report, Fortis Inc. (January 6, 2016) p. 9. Calculated by subtracting the debt to capital ratio reported from 1.

56.10 In response BCUC IR 44.3, Mr. Coyne provided a response on the assumption that the goodwill was fully financed by equity. In Mr. Coyne's view, is that a reasonable assumption in the case of Fortis Inc.?

Response:

Per Mr. Coyne's discussions with FEI Treasury representatives, Fortis Inc.'s goodwill financing is transaction dependent. It is Mr. Coyne's understanding that although a substantial portion of goodwill has been financed with equity, debt is also commonly employed to finance acquisitions.

56.11 Please explain if the existence of its goodwill contributes to weaker credit metrics for Fortis Inc. than would otherwise be the case in the absence of goodwill on the assumption that the goodwill is financed partially by debt as appears to be the case for Fortis Inc.

Response:

To respond, one must make assumptions regarding the overall capitalization of the acquisition. Assuming the hypothetical suggests that goodwill was financed at least partially with debt, and the remainder was financed with equity, as debt is employed in the financing, interest coverage and fixed charge metrics would weaken as would cash flow-to-debt metrics. To the extent the acquisition (and goodwill) is financed with the same ratio of equity and debt as in the existing capital structure, the debt to capital ratio would not change. Any financing that will increase the level of debt in the capital structure would weaken Fortis Inc.'s debt to capital ratio.

57.0 Reference: Exhibit B-9, BCUC IR 27.1 and 27.3

Commodity Rate volatility

In BCUC IR 27.1, FEI showed the Commodity Cost Reconciliation Account (CCRA) Portfolio Weighted Average Cost of Gas (WACOG) (without Hedging). FEI stated:

> Although the overall natural gas price level from 2012 to 2015 has lowered compared to historical price levels, the WACOG and CCRA rate remained volatile. As illustrated in the figure above, FEI experienced multiple CCRA rate changes from 2012 through 2015. The CCRA rate increased from $3.272/GJ to $4.640/GJ (a 42% increase) on April 1, 2015 before dropping down to $1.719/GJ as of January 2016 (a drop of 55% from January 2015).

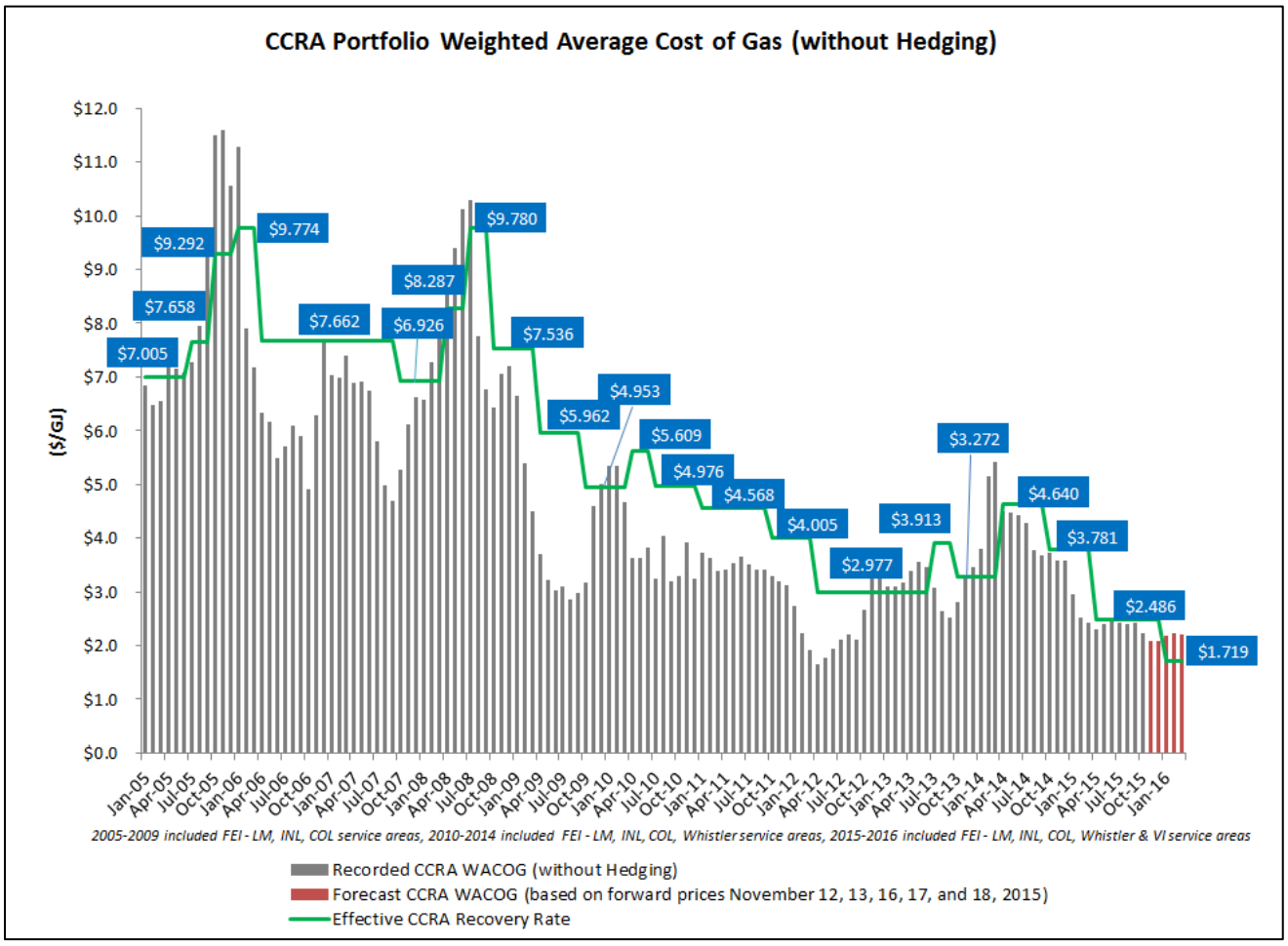
In BCUC IR 27.3, FEI stated:

> Customers' perception is not only affected by their monthly bills but by what they hear on the everyday news as well. For instance, news regarding a change in natural gas prices may lead to some customers' anticipation of a similar immediate change in their monthly bills.

57.1 With respect to the graph in BCUC IR 27.1, please add the numerical CCRA rate to accompany the graph.

Response:

The following figure has been updated to include the numerical CCRA rate.



57.1.1 For each instance that there was a CCRA rate change, please include the corresponding average annual customer bill impact (i.e. residential, commercial, and industrial), in dollars and percentages, only taking into account the CCRA rate change.

Response:

This response addresses BCUC IRs 2.57.1.1, 2.57.1.2., and 2.57.6.

The following tables and figures summarize the annual customer bill impact (in dollars and percentages) from January 1, 2009 to January 1, 2016 for rate class 1, rate class 3, and rate class 5 for each instance that there was a CCRA rate change and taking into account first the

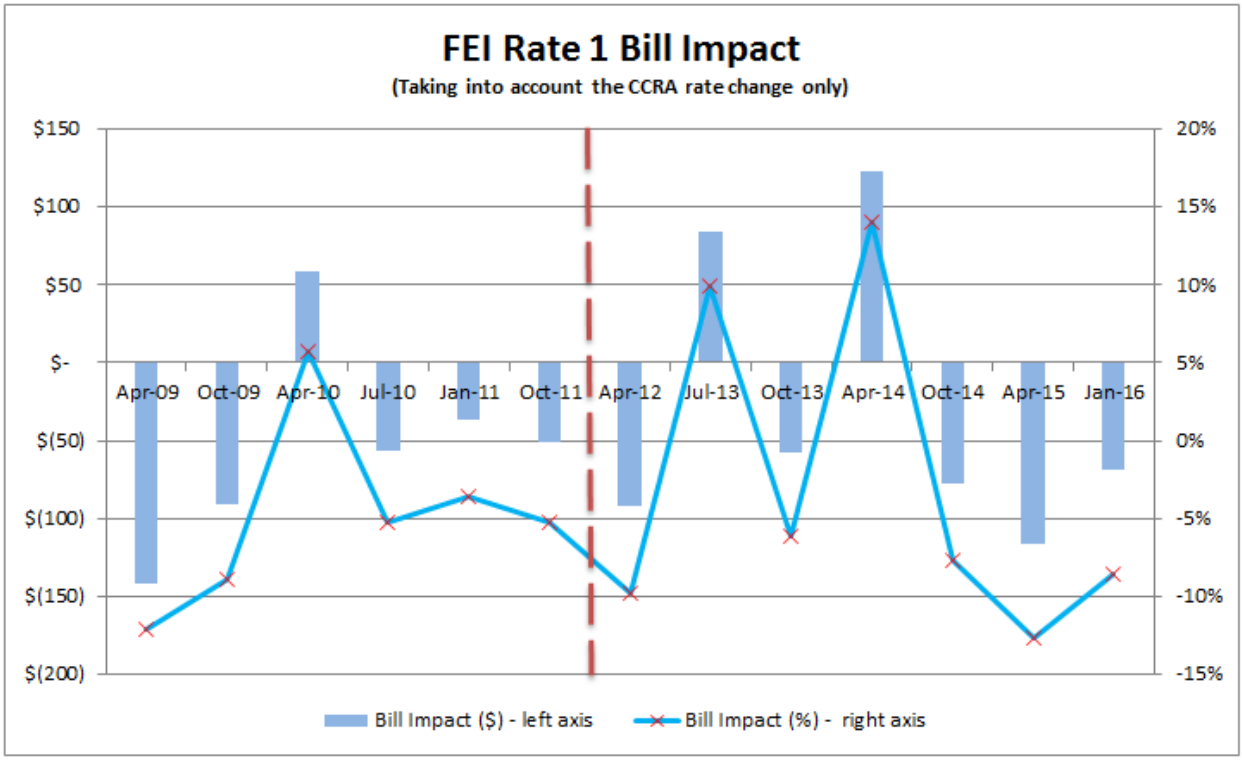
CCRA rate change only and then the combined delivery, transport and storage, and CCRA rate changes. FEI has used rate class 1 for residential customers, rate class 3 for commercial customers and rate class 5 for industrial customers. Due to the number of different industrial rate schedules and the large variation in the consumption between and within industrial rate schedules, FEI has used the average annual customer bill impact for industrial customers using rate changes for FEI Rate Schedule 5 customer bills with an average annual consumption of 9,422 gigajoules and a daily demand of 50.7 gigajoules.

FEI Bill Impact - taking into account the CCRA rate change only

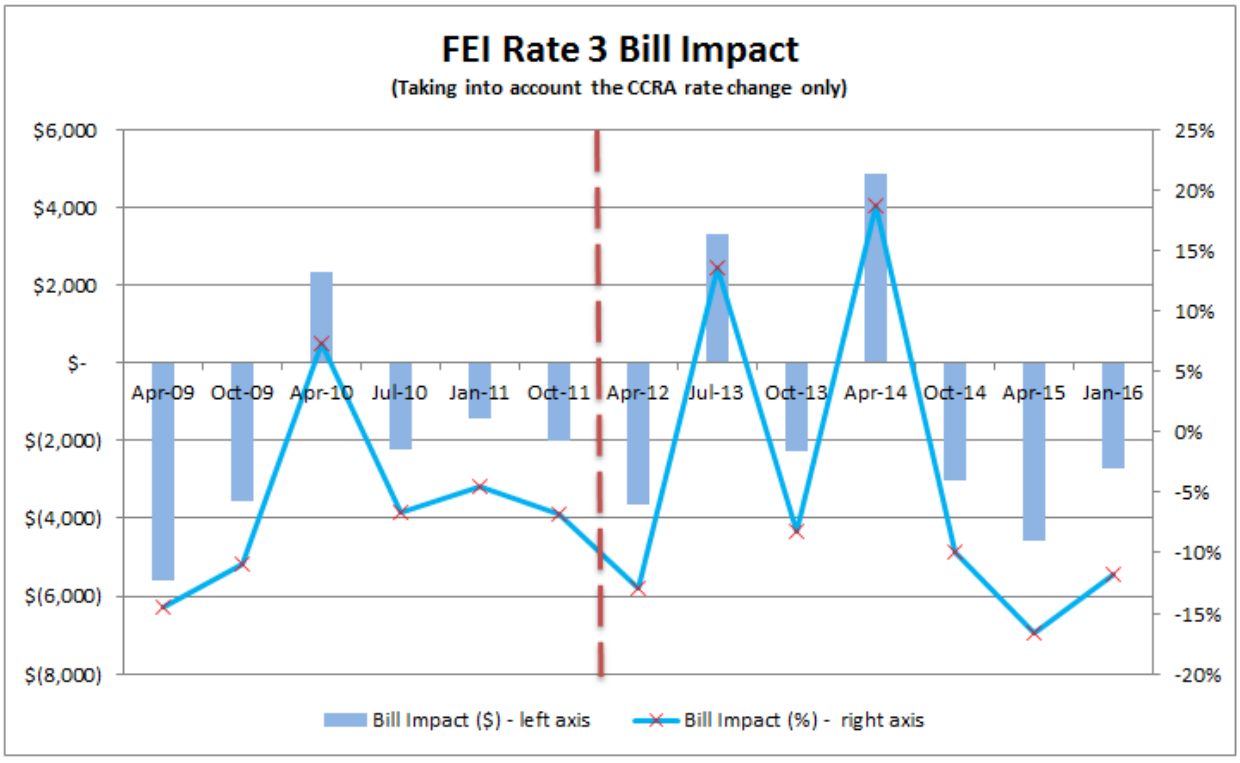
Month	CCRA Rate ($/GJ)[1]	CCRA Change ($/GJ)	Impact on Annual Customer Bill ($) Rate 1	Rate 3	Rate 5	Impact on Annual Customer Bill (%) Rate 1	Rate 3	Rate 5
Apr-09	$ 5.962	$ (1.574)	$ (142)	$ (5,586)	$ (14,830)	-12%	-14%	-15%
Oct-09	$ 4.953	$ (1.009)	$ (91)	$ (3,581)	$ (9,507)	-9%	-11%	-11%
Apr-10	$ 5.609	$ 0.656	$ 59	$ 2,328	$ 6,181	6%	7%	8%
Jul-10	$ 4.976	$ (0.633)	$ (57)	$ (2,247)	$ (5,964)	-5%	-7%	-7%
Jan-11	$ 4.568	$ (0.408)	$ (37)	$ (1,448)	$ (3,844)	-4%	-5%	-5%
Oct-11	$ 4.005	$ (0.563)	$ (51)	$ (1,998)	$ (5,305)	-5%	-7%	-7%
Apr-12	$ 2.977	$ (1.028)	$ (93)	$ (3,648)	$ (9,686)	-10%	-13%	-14%
Jul-13	$ 3.913	$ 0.936	$ 84	$ 3,322	$ 8,819	10%	14%	15%
Oct-13	$ 3.272	$ (0.641)	$ (58)	$ (2,275)	$ (6,040)	-6%	-8%	-9%
Apr-14	$ 4.640	$ 1.368	$ 123	$ 4,855	$ 12,889	14%	19%	20%
Oct-14	$ 3.781	$ (0.859)	$ (77)	$ (3,049)	$ (8,093)	-8%	-10%	-11%
Apr-15	$ 2.486	$ (1.295)	$ (117)	$ (4,596)	$ (12,201)	-13%	-17%	-18%
Jan-16	$ 1.719	$ (0.767)	$ (69)	$ (2,722)	$ (7,227)	-9%	-12%	-13%

FEI Bill Impact - taking into account the combined delivery, transport and storage, and CCRA rate changes

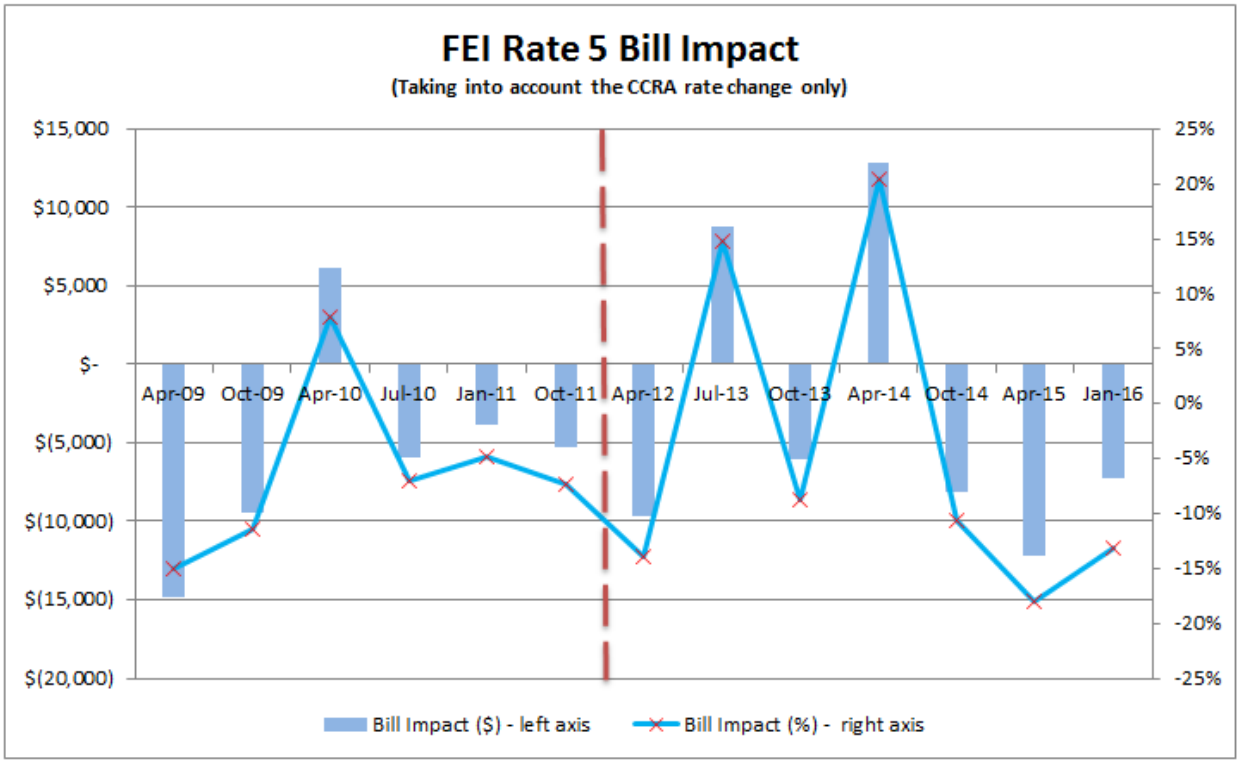
Month	CCRA Rate ($/GJ)[1]	CCRA Rate Change ($/GJ)	Total Rate Changes Rate 1	Total Rate Changes Rate 3	Total Rate Changes Rate 5	Impact on Annual Customer Bill ($) Rate 1	Rate 3	Rate 5	Impact on Annual Customer Bill (%) Rate 1	Rate 3	Rate 5
Apr-09	$ 5.962	$ (1.574)	$ (1.644)	$ (1.615)	$ (1.611)	$(148)	$ (5,731)	$(15,178)	-13%	-15%	-15%
Oct-09	$ 4.953	$ (1.009)	$ (1.009)	$ (1.009)	$ (1.009)	$ (91)	$ (3,581)	$ (9,507)	-9%	-11%	-11%
Apr-10	$ 5.609	$ 0.656	$ 0.656	$ 0.656	$ 0.656	$ 59	$ 2,328	$ 6,181	6%	7%	8%
Jul-10	$ 4.976	$ (0.633)	$ (0.633)	$ (0.633)	$ (0.633)	$ (57)	$ (2,247)	$ (5,964)	-5%	-7%	-7%
Jan-11	$ 4.568	$ (0.408)	$ (0.722)	$ (0.620)	$ (0.592)	$ (65)	$ (2,200)	$ (5,577)	-6%	-7%	-7%
Oct-11	$ 4.005	$ (0.563)	$ (0.563)	$ (0.563)	$ (0.563)	$ (51)	$ (1,998)	$ (5,305)	-5%	-7%	-7%
Apr-12	$ 2.977	$ (1.028)	$ (1.028)	$ (1.028)	$ (1.028)	$ (93)	$ (3,648)	$ (9,686)	-10%	-13%	-14%
Jul-13	$ 3.913	$ 0.936	$ 0.642	$ 0.762	$ 0.846	$ 58	$ 2,704	$ 7,968	7%	11%	13%
Oct-13	$ 3.272	$ (0.641)	$ (0.641)	$ (0.641)	$ (0.641)	$ (58)	$ (2,275)	$ (6,040)	-6%	-8%	-9%
Apr-14	$ 4.640	$ 1.368	$ 1.368	$ 1.368	$ 1.368	$ 123	$ 4,855	$ 12,889	14%	19%	20%
Oct-14	$ 3.781	$ (0.859)	$ (0.859)	$ (0.859)	$ (0.859)	$ (77)	$ (3,049)	$ (8,093)	-8%	-10%	-11%
Apr-15	$ 2.486	$ (1.295)	$ (1.295)	$ (1.295)	$ (1.295)	$(117)	$ (4,596)	$(12,201)	-13%	-17%	-18%
Jan-16	$ 1.719	$ (0.767)	$ (0.721)	$ (0.733)	$ (0.939)	$ (65)	$ (2,601)	$ (8,849)	-8%	-11%	-16%


FEI Rate 1 Bill Impact
(Taking into account the CCRA rate change only)
$150
$100
$50
$-
$(50)
$(100)
$(150)
$(200)
20%
15%
10%
5%
0%
-5%
-10%
-15%
Apr-09
Oct-09
Apr-10
Jul-10
Jan-11
Oct-11
Apr-12
Jul-13
Oct-13
Apr-14
Oct-14
Apr-15
Jan-16
Bill Impact ($) - left axis
Bill Impact (%) - right axis

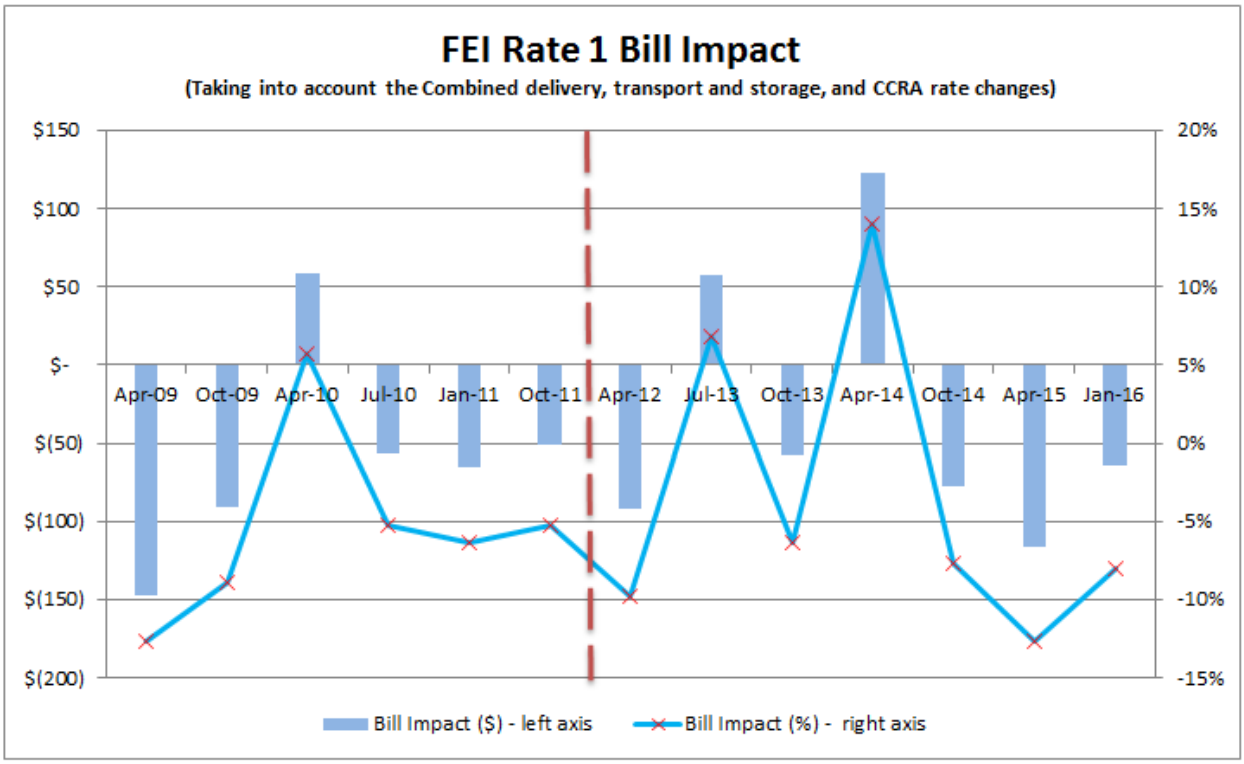
1


FEI Rate 3 Bill Impact
(Taking into account the CCRA rate change only)
$6,000
$4,000
$2,000
$-
$(2,000)
$(4,000)
$(6,000)
$(8,000)
25%
20%
15%
10%
5%
0%
-5%
-10%
-15%
-20%
Apr-09
Oct-09
Apr-10
Jul-10
Jan-11
Oct-11
Apr-12
Jul-13
Oct-13
Apr-14
Oct-14
Apr-15
Jan-16
Bill Impact ($) - left axis
Bill Impact (%) - right axis

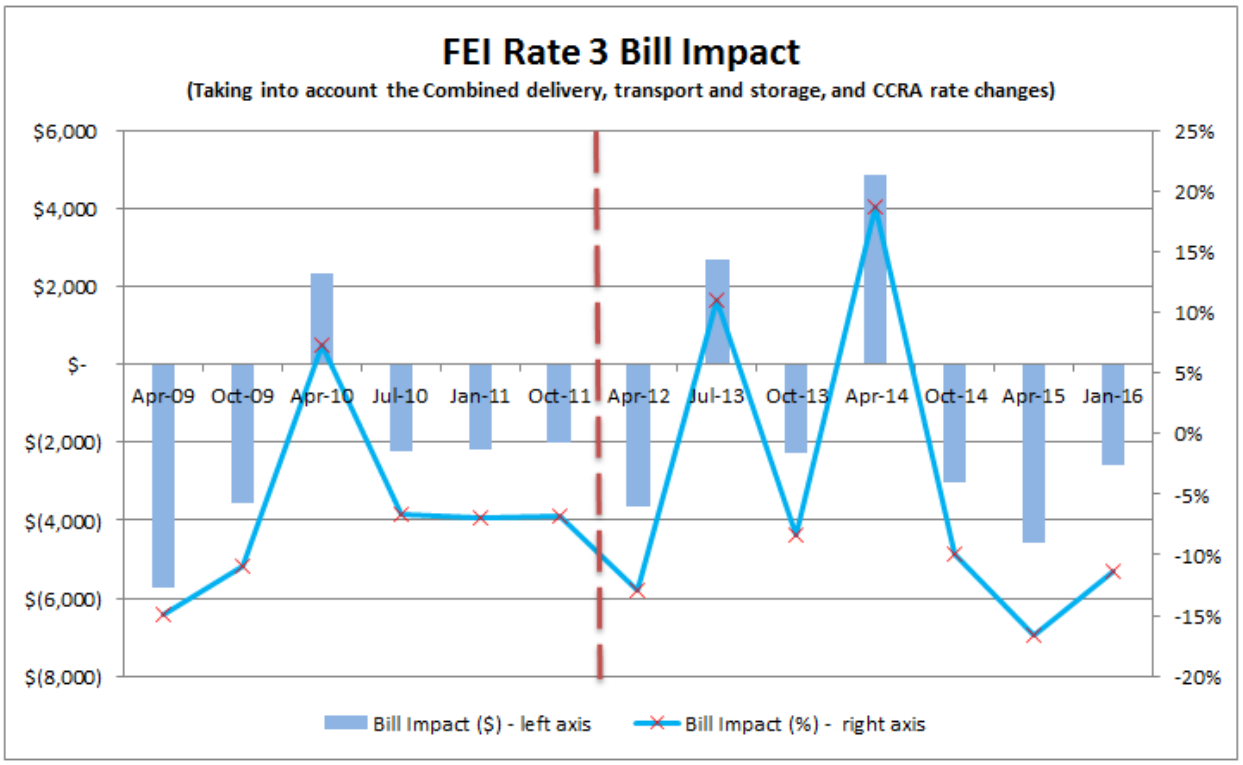
2


FEI Rate 5 Bill Impact
(Taking into account the CCRA rate change only)
$15,000
$10,000
$5,000
$-
$(5,000)
$(10,000)
$(15,000)
$(20,000)
25%
20%
15%
10%
5%
0%
-5%
-10%
-15%
-20%
-25%
Apr-09
Oct-09
Apr-10
Jul-10
Jan-11
Oct-11
Apr-12
Jul-13
Oct-13
Apr-14
Oct-14
Apr-15
Jan-16
Bill Impact ($) - left axis
Bill Impact (%) - right axis

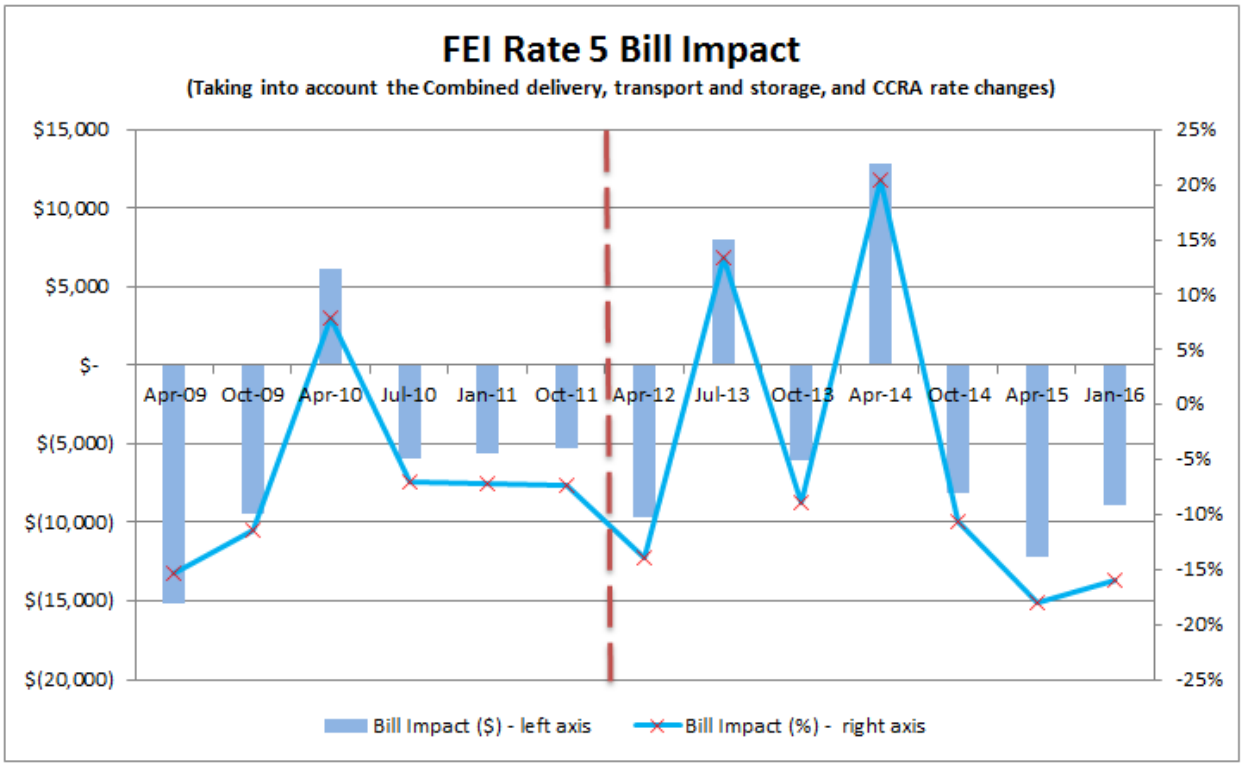
1


FEI Rate 1 Bill Impact
(Taking into account the Combined delivery, transport and storage, and CCRA rate changes)
$150
$100
$50
$-
$(50)
$(100)
$(150)
$(200)
20%
15%
10%
5%
0%
-5%
-10%
-15%
Apr-09
Oct-09
Apr-10
Jul-10
Jan-11
Oct-11
Apr-12
Jul-13
Oct-13
Apr-14
Oct-14
Apr-15
Jan-16
Bill Impact ($) - left axis
Bill Impact (%) - right axis

2


FEI Rate 3 Bill Impact
(Taking into account the Combined delivery, transport and storage, and CCRA rate changes)
$6,000
$4,000
$2,000
$-
$(2,000)
$(4,000)
$(6,000)
$(8,000)
25%
20%
15%
10%
5%
0%
-5%
-10%
-15%
-20%
Apr-09
Oct-09
Apr-10
Jul-10
Jan-11
Oct-11
Apr-12
Jul-13
Oct-13
Apr-14
Oct-14
Apr-15
Jan-16
Bill Impact ($) - left axis
Bill Impact (%) - right axis

1


FEI Rate 5 Bill Impact
(Taking into account the Combined delivery, transport and storage, and CCRA rate changes)
$15,000
$10,000
$5,000
$-
$(5,000)
$(10,000)
$(15,000)
$(20,000)
25%
20%
15%
10%
5%
0%
-5%
-10%
-15%
-20%
-25%
Apr-09
Oct-09
Apr-10
Jul-10
Jan-11
Oct-11
Apr-12
Jul-13
Oct-13
Apr-14
Oct-14
Apr-15
Jan-16
Bill Impact ($) - left axis
Bill Impact (%) - right axis

2

As illustrated by the figures above, for each instance that there is a CCRA rate change from January 2009 to January 2016, FEI's bill impact, in both dollars and percentages, exhibited similar patterns for rate class 1, rate class 3, and rate class 5. The only difference is that, due to higher consumption volumes, rate class 3 and rate class 5 show higher magnitudes of bill impact in both dollars and percentages for each instance that there is a CCRA rate change.

Moreover, the bill impact (in both dollars and percentages) between taking into account the CCRA rate change only or the combined delivery, transport and storage, and CCRA rate changes are not materially different in each instance that there is a CCRA rate change. The reason is that, in general, the delivery rate and storage and transportation rate don't change as often or typically to the same degree as the CCRA rate change. Therefore, the CCRA rate changes are the primary driver of bill impact fluctuations for customers.

Based on the customer bill impact analysis above, the CCRA rate and customers' bills are more volatile during the 2012-2015 period than the 2009-2012 period. For the three rate classes in general, the impacts to customers' bills, at least in percentage terms, were greater in terms of positive and negative changes during 2012-2015. There were also more increases and decreases in terms of bill impacts during 2012-2015 as customers experienced two sets of significant increases and decreases, compared to only one smaller increase and decrease during 2009-2012.

57.1.2 For each instance that there was a CCRA rate change, please include the corresponding average annual customer bill impact (i.e. residential, commercial, and industrial), in dollars and percentages, taking into account the combined delivery, transport and storage, and CCRA rate changes.

Response:

Please refer to the response to BCUC IR 2.57.1.1.

57.2 Please calculate the mean absolute deviation for the CCRA rate for the period from January 1, 2005 to January 1, 2016. Please show your calculations.

Response:

FEI provides below the data and calculations requested in the responses to BCUC IRs 2.57.2 to 2.57.5 as well as a summary table of the results within this response.

The following table summarizes the mean and mean absolute deviation (MAD) values (in $ and %) for FEI's CCRA rate and WACOG (excluding hedging) for the periods of January 1, 2005-January 1, 2016, 2009-2012, and 2012-2015. In order to provide a proper comparison of MAD between periods with different price levels, FEI has also calculated the MAD as a percentage of its mean. The detailed calculations are provided below.

		Jan. 1, 2005 - Jan. 1, 2016	2009 - 2012	2012 - 2015
CCRA Rate	Mean ($/GJ)	$ 5.43	$ 4.72	$ 3.35
	Mean Absolute Deviation ($/GJ)	$ 1.90	$ 0.89	$ 0.58
	Mean Absolute Deviation (in %)	34.99%	18.90%	17.31%
WACOG (excluding hedging)	Mean ($/GJ)	$ 4.80	$ 3.43	$ 3.01
	Mean Absolute Deviation ($/GJ)	$ 1.92	$ 0.71	$ 0.72
	Mean Absolute Deviation (in %)	39.93%	20.70%	23.95%

Based on MAD, the CCRA rate has a slightly lower deviation in 2012-2015 (17.31%) compared to 2009-2012 (18.90%) but a higher deviation of 23.95% for WACOG in 2012-2015 than 20.70% in 2009-2012. Although the CCRA rate deviation is slightly lower and the WACOG deviation is higher in 2012-2015 than 2009-2012, those measures should not be the only factors to compare volatility.

For example, the magnitude of rate change is an important factor as well. After experiencing cold weather and price spikes in winter 2013/14, the CCRA rate increased by $1.368/GJ effective April 2014, whereas the largest rate increase during 2009-2012 was only $0.656/GJ.

The following tables illustrate the calculation for MAD for FEI's CCRA rate and WACOG (excluding hedging) for the periods of January 1, 2005-January 1, 2016, 2009-2012, and 2012-2015.

FEI Effective CCRA Recovery Rates MAD Calculation
($/GJ)

	(A)	(C) (Column A minus B)	(D) (Absolute Value of Column C)
Month	**CCRA Rate**	**Deviation**	**Absolute Deviation**
Jan-05	$ 7.005	$ 1.579	$ 1.579
Apr-05	$ 7.005	$ 1.579	$ 1.579
Jul-05	$ 7.658	$ 2.232	$ 2.232
Oct-05	$ 9.292	$ 3.866	$ 3.866
Jan-06	$ 9.774	$ 4.348	$ 4.348
Apr-06	$ 7.662	$ 2.236	$ 2.236
Jul-06	$ 7.662	$ 2.236	$ 2.236
Oct-06	$ 7.662	$ 2.236	$ 2.236
Jan-07	$ 7.662	$ 2.236	$ 2.236
Apr-07	$ 7.662	$ 2.236	$ 2.236
Jul-07	$ 7.662	$ 2.236	$ 2.236
Oct-07	$ 6.926	$ 1.500	$ 1.500
Jan-08	$ 6.926	$ 1.500	$ 1.500
Apr-08	$ 8.287	$ 2.861	$ 2.861
Jul-08	$ 9.780	$ 4.354	$ 4.354
Oct-08	$ 7.536	$ 2.110	$ 2.110
Jan-09	$ 7.536	$ 2.110	$ 2.110
Apr-09	$ 5.962	$ 0.536	$ 0.536
Jul-09	$ 5.962	$ 0.536	$ 0.536
Oct-09	$ 4.953	$ (0.473)	$ 0.473
Jan-10	$ 4.953	$ (0.473)	$ 0.473
Apr-10	$ 5.609	$ 0.183	$ 0.183
Jul-10	$ 4.976	$ (0.450)	$ 0.450
Oct-10	$ 4.976	$ (0.450)	$ 0.450
Jan-11	$ 4.568	$ (0.858)	$ 0.858
Apr-11	$ 4.568	$ (0.858)	$ 0.858
Jul-11	$ 4.568	$ (0.858)	$ 0.858
Oct-11	$ 4.005	$ (1.421)	$ 1.421
Jan-12	$ 4.005	$ (1.421)	$ 1.421
Apr-12	$ 2.977	$ (2.449)	$ 2.449
Jul-12	$ 2.977	$ (2.449)	$ 2.449
Oct-12	$ 2.977	$ (2.449)	$ 2.449
Jan-13	$ 2.977	$ (2.449)	$ 2.449
Apr-13	$ 2.977	$ (2.449)	$ 2.449
Jul-13	$ 3.913	$ (1.513)	$ 1.513
Oct-13	$ 3.272	$ (2.154)	$ 2.154
Jan-14	$ 3.272	$ (2.154)	$ 2.154
Apr-14	$ 4.640	$ (0.786)	$ 0.786
Jul-14	$ 4.640	$ (0.786)	$ 0.786
Oct-14	$ 3.781	$ (1.645)	$ 1.645
Jan-15	$ 3.781	$ (1.645)	$ 1.645
Apr-15	$ 2.486	$ (2.940)	$ 2.940
Jul-15	$ 2.486	$ (2.940)	$ 2.940
Oct-15	$ 2.486	$ (2.940)	$ 2.940
Jan-16	$ 1.719	$ (3.707)	$ 3.707
Mean (Average of Column A)	**$ 5.43** (B)	**MAD**	**$ 1.90** (E) (Average of Column D)
		MAD (%)	**34.99%** (F) (E/B)

FEI Effective CCRA Recovery Rates MAD Calculation
($/GJ)

Month	(A) CCRA Rate	(C) (Column A minus B) Deviation	(D) (Absolute Value of Column C) Absolute Deviation
Jan-09	$ 7.536	$ 2.813	$ 2.813
Apr-09	$ 5.962	$ 1.239	$ 1.239
Jul-09	$ 5.962	$ 1.239	$ 1.239
Oct-09	$ 4.953	$ 0.230	$ 0.230
Jan-10	$ 4.953	$ 0.230	$ 0.230
Apr-10	$ 5.609	$ 0.886	$ 0.886
Jul-10	$ 4.976	$ 0.253	$ 0.253
Oct-10	$ 4.976	$ 0.253	$ 0.253
Jan-11	$ 4.568	$ (0.155)	$ 0.155
Apr-11	$ 4.568	$ (0.155)	$ 0.155
Jul-11	$ 4.568	$ (0.155)	$ 0.155
Oct-11	$ 4.005	$ (0.718)	$ 0.718
Jan-12	$ 4.005	$ (0.718)	$ 0.718
Apr-12	$ 2.977	$ (1.746)	$ 1.746
Jul-12	$ 2.977	$ (1.746)	$ 1.746
Oct-12	$ 2.977	$ (1.746)	$ 1.746
Mean	**$ 4.72** (B) (Average of Column A)	**MAD**	**$ 0.89** (E) (Average of Column D)
		MAD (%)	**18.90%** (F) (E/B)

FEI Effective CCRA Recovery Rates MAD Calculation
($/GJ)

Month	(A) CCRA Rate	(C) (Column A minus B) Deviation	(D) (Absolute Value of Column C) Absolute Deviation
Jan-12	$ 4.005	$ 0.652	$ 0.652
Apr-12	$ 2.977	$ (0.376)	$ 0.376
Jul-12	$ 2.977	$ (0.376)	$ 0.376
Oct-12	$ 2.977	$ (0.376)	$ 0.376
Jan-13	$ 2.977	$ (0.376)	$ 0.376
Apr-13	$ 2.977	$ (0.376)	$ 0.376
Jul-13	$ 3.913	$ 0.560	$ 0.560
Oct-13	$ 3.272	$ (0.081)	$ 0.081
Jan-14	$ 3.272	$ (0.081)	$ 0.081
Apr-14	$ 4.640	$ 1.287	$ 1.287
Jul-14	$ 4.640	$ 1.287	$ 1.287
Oct-14	$ 3.781	$ 0.428	$ 0.428
Jan-15	$ 3.781	$ 0.428	$ 0.428
Apr-15	$ 2.486	$ (0.867)	$ 0.867
Jul-15	$ 2.486	$ (0.867)	$ 0.867
Oct-15	$ 2.486	$ (0.867)	$ 0.867
Mean	**$ 3.35** (B) (Average of Column A)	**MAD**	**$ 0.58** (E) (Average of Column D)
		MAD (%)	**17.31%** (F) (E/B)

FEI WACOG (excluding hedging) MAD calculation
($/GJ)

	(A)	(C) (Column A minus B)	(D) (Absolute Value of Column C)
Month	**WACOG**	**Deviation**	**Absolute Deviation**
Jan-05	$ 6.83	$ 2.030	$ 2.030
Feb-05	$ 6.48	$ 1.676	$ 1.676
Mar-05	$ 6.56	$ 1.758	$ 1.758
Apr-05	$ 7.62	$ 2.816	$ 2.816
May-05	$ 7.16	$ 2.358	$ 2.358
Jun-05	$ 7.09	$ 2.287	$ 2.287
Jul-05	$ 7.27	$ 2.467	$ 2.467
Aug-05	$ 7.95	$ 3.146	$ 3.146
Sep-05	$ 9.77	$ 4.975	$ 4.975
Oct-05	$ 11.50	$ 6.704	$ 6.704
Nov-05	$ 11.60	$ 6.803	$ 6.803
Dec-05	$ 10.55	$ 5.754	$ 5.754
Jan-06	$ 11.28	$ 6.481	$ 6.481
Feb-06	$ 7.91	$ 3.110	$ 3.110
Mar-06	$ 7.17	$ 2.375	$ 2.375
Apr-06	$ 6.34	$ 1.542	$ 1.542
May-06	$ 6.17	$ 1.373	$ 1.373
Jun-06	$ 5.49	$ 0.687	$ 0.687
Jul-06	$ 5.69	$ 0.896	$ 0.896
Aug-06	$ 6.08	$ 1.281	$ 1.281
Sep-06	$ 5.91	$ 1.109	$ 1.109
Oct-06	$ 4.91	$ 0.109	$ 0.109
Nov-06	$ 6.30	$ 1.497	$ 1.497
Dec-06	$ 7.68	$ 2.881	$ 2.881
Jan-07	$ 7.03	$ 2.232	$ 2.232
Feb-07	$ 6.98	$ 2.186	$ 2.186
Mar-07	$ 7.38	$ 2.586	$ 2.586
Apr-07	$ 6.89	$ 2.088	$ 2.088
May-07	$ 6.92	$ 2.121	$ 2.121
Jun-07	$ 6.74	$ 1.940	$ 1.940
Jul-07	$ 5.81	$ 1.007	$ 1.007
Aug-07	$ 4.98	$ 0.184	$ 0.184
Sep-07	$ 4.70	$ (0.098)	$ 0.098
Oct-07	$ 5.28	$ 0.482	$ 0.482
Nov-07	$ 6.11	$ 1.314	$ 1.314

	(A)	(C) (Column A minus B)	(D) (Absolute Value of Column C)
Month	**WACOG**	**Deviation**	**Absolute Deviation**
Dec-07	$ 6.62	$ 1.824	$ 1.824
Jan-08	$ 6.57	$ 1.775	$ 1.775
Feb-08	$ 7.28	$ 2.483	$ 2.483
Mar-08	$ 7.74	$ 2.946	$ 2.946
Apr-08	$ 8.59	$ 3.787	$ 3.787
May-08	$ 9.39	$ 4.591	$ 4.591
Jun-08	$ 10.13	$ 5.328	$ 5.328
Jul-08	$ 10.28	$ 5.484	$ 5.484
Aug-08	$ 7.77	$ 2.967	$ 2.967
Sep-08	$ 6.77	$ 1.975	$ 1.975
Oct-08	$ 6.43	$ 1.636	$ 1.636
Nov-08	$ 7.07	$ 2.269	$ 2.269
Dec-08	$ 7.21	$ 2.413	$ 2.413
Jan-09	$ 6.64	$ 1.844	$ 1.844
Feb-09	$ 5.38	$ 0.586	$ 0.586
Mar-09	$ 4.51	$ (0.289)	$ 0.289
Apr-09	$ 3.70	$ (1.095)	$ 1.095
May-09	$ 3.21	$ (1.585)	$ 1.585
Jun-09	$ 3.03	$ (1.764)	$ 1.764
Jul-09	$ 3.10	$ (1.704)	$ 1.704
Aug-09	$ 2.86	$ (1.935)	$ 1.935
Sep-09	$ 2.97	$ (1.829)	$ 1.829
Oct-09	$ 3.18	$ (1.618)	$ 1.618
Nov-09	$ 4.59	$ (0.210)	$ 0.210
Dec-09	$ 5.01	$ 0.216	$ 0.216
Jan-10	$ 5.35	$ 0.549	$ 0.549
Feb-10	$ 5.35	$ 0.548	$ 0.548
Mar-10	$ 4.67	$ (0.125)	$ 0.125
Apr-10	$ 3.63	$ (1.165)	$ 1.165
May-10	$ 3.62	$ (1.182)	$ 1.182
Jun-10	$ 3.81	$ (0.988)	$ 0.988
Jul-10	$ 3.23	$ (1.567)	$ 1.567
Aug-10	$ 4.03	$ (0.765)	$ 0.765
Sep-10	$ 3.20	$ (1.598)	$ 1.598
Oct-10	$ 3.29	$ (1.513)	$ 1.513
Nov-10	$ 3.91	$ (0.890)	$ 0.890
Dec-10	$ 3.25	$ (1.550)	$ 1.550
Jan-11	$ 3.73	$ (1.069)	$ 1.069
Feb-11	$ 3.64	$ (1.159)	$ 1.159
Mar-11	$ 3.40	$ (1.403)	$ 1.403
Apr-11	$ 3.42	$ (1.377)	$ 1.377
May-11	$ 3.53	$ (1.265)	$ 1.265
Jun-11	$ 3.66	$ (1.136)	$ 1.136

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	(A)	(C) (Column A minus B)	(D) (Absolute Value of Column C)
Month	**WACOG**	**Deviation**	**Absolute Deviation**
Sep-11	$ 3.40	$ (1.399)	$ 1.399
Oct-11	$ 3.30	$ (1.497)	$ 1.497
Nov-11	$ 3.21	$ (1.593)	$ 1.593
Dec-11	$ 3.12	$ (1.684)	$ 1.684
Jan-12	$ 2.73	$ (2.070)	$ 2.070
Feb-12	$ 2.23	$ (2.569)	$ 2.569
Mar-12	$ 1.90	$ (2.894)	$ 2.894
Apr-12	$ 1.65	$ (3.150)	$ 3.150
May-12	$ 1.76	$ (3.035)	$ 3.035
Jun-12	$ 1.95	$ (2.851)	$ 2.851
Jul-12	$ 2.11	$ (2.690)	$ 2.690
Aug-12	$ 2.20	$ (2.594)	$ 2.594
Sep-12	$ 2.12	$ (2.682)	$ 2.682
Oct-12	$ 2.67	$ (2.131)	$ 2.131
Nov-12	$ 3.29	$ (1.509)	$ 1.509
Dec-12	$ 3.33	$ (1.473)	$ 1.473
Jan-13	$ 3.09	$ (1.712)	$ 1.712
Feb-13	$ 3.09	$ (1.709)	$ 1.709
Mar-13	$ 3.18	$ (1.623)	$ 1.623
Apr-13	$ 3.39	$ (1.407)	$ 1.407
May-13	$ 3.55	$ (1.251)	$ 1.251
Jun-13	$ 3.47	$ (1.332)	$ 1.332
Jul-13	$ 3.06	$ (1.736)	$ 1.736
Aug-13	$ 2.65	$ (2.149)	$ 2.149
Sep-13	$ 2.52	$ (2.281)	$ 2.281
Oct-13	$ 2.80	$ (1.996)	$ 1.996
Nov-13	$ 3.30	$ (1.504)	$ 1.504
Dec-13	$ 3.45	$ (1.344)	$ 1.344
Jan-14	$ 3.81	$ (0.990)	$ 0.990
Feb-14	$ 5.16	$ 0.357	$ 0.357
Mar-14	$ 5.42	$ 0.624	$ 0.624
Apr-14	$ 4.49	$ (0.306)	$ 0.306
May-14	$ 4.47	$ (0.325)	$ 0.325
Jun-14	$ 4.43	$ (0.366)	$ 0.366
Jul-14	$ 4.28	$ (0.519)	$ 0.519
Aug-14	$ 3.78	$ (1.018)	$ 1.018
Sep-14	$ 3.67	$ (1.124)	$ 1.124
Oct-14	$ 3.72	$ (1.075)	$ 1.075
Nov-14	$ 3.58	$ (1.218)	$ 1.218
Dec-14	$ 3.58	$ (1.219)	$ 1.219
Jan-15	$ 2.96	$ (1.841)	$ 1.841
Feb-15	$ 2.51	$ (2.288)	$ 2.288
Mar-15	$ 2.42	$ (2.377)	$ 2.377
Apr-15	$ 2.29	$ (2.505)	$ 2.505
May-15	$ 2.39	$ (2.406)	$ 2.406
Jun-15	$ 2.49	$ (2.309)	$ 2.309
Jul-15	$ 2.42	$ (2.379)	$ 2.379
Aug-15	$ 2.40	$ (2.395)	$ 2.395
Sep-15	$ 2.42	$ (2.376)	$ 2.376
Oct-15	$ 2.22	$ (2.579)	$ 2.579
Nov-15	$ 2.08	$ (2.718)	$ 2.718
Dec-15	$ 2.08	$ (2.714)	$ 2.714
Mean (Average of Column A)	**$ 4.80** (B)	**MAD**	**$ 1.92** (E) (Average of Column D)
		MAD (%)	**39.93%** (F) (E/B)

FEI WACOG (excluding hedging) MAD calculation
($/GJ)

	(A)	(C) (Column A minus B)	(D) (Absolute Value of Column C)
Month	**WACOG**	**Deviation**	**Absolute Deviation**
Jan-09	$ 6.643	$ 3.209	$ 3.209
Feb-09	$ 5.384	$ 1.951	$ 1.951
Mar-09	$ 4.509	$ 1.076	$ 1.076
Apr-09	$ 3.704	$ 0.270	$ 0.270
May-09	$ 3.214	$ (0.220)	$ 0.220
Jun-09	$ 3.035	$ (0.399)	$ 0.399
Jul-09	$ 3.095	$ (0.339)	$ 0.339
Aug-09	$ 2.864	$ (0.570)	$ 0.570
Sep-09	$ 2.970	$ (0.464)	$ 0.464
Oct-09	$ 3.181	$ (0.253)	$ 0.253
Nov-09	$ 4.589	$ 1.155	$ 1.155
Dec-09	$ 5.015	$ 1.581	$ 1.581
Jan-10	$ 5.348	$ 1.914	$ 1.914
Feb-10	$ 5.346	$ 1.913	$ 1.913
Mar-10	$ 4.674	$ 1.240	$ 1.240
Apr-10	$ 3.634	$ 0.200	$ 0.200
May-10	$ 3.616	$ 0.183	$ 0.183
Jun-10	$ 3.811	$ 0.377	$ 0.377
Jul-10	$ 3.232	$ (0.202)	$ 0.202
Aug-10	$ 4.034	$ 0.600	$ 0.600
Sep-10	$ 3.201	$ (0.233)	$ 0.233
Oct-10	$ 3.285	$ (0.148)	$ 0.148
Nov-10	$ 3.909	$ 0.475	$ 0.475
Dec-10	$ 3.249	$ (0.185)	$ 0.185
Jan-11	$ 3.730	$ 0.296	$ 0.296
Feb-11	$ 3.639	$ 0.206	$ 0.206
Mar-11	$ 3.396	$ (0.038)	$ 0.038
Apr-11	$ 3.422	$ (0.012)	$ 0.012
May-11	$ 3.534	$ 0.100	$ 0.100
Jun-11	$ 3.663	$ 0.229	$ 0.229
Jul-11	$ 3.519	$ 0.085	$ 0.085
Aug-11	$ 3.419	$ (0.015)	$ 0.015
Sep-11	$ 3.400	$ (0.034)	$ 0.034
Oct-11	$ 3.302	$ (0.132)	$ 0.132
Nov-11	$ 3.205	$ (0.228)	$ 0.228
Dec-11	$ 3.115	$ (0.319)	$ 0.319
Jan-12	$ 2.729	$ (0.705)	$ 0.705
Feb-12	$ 2.229	$ (1.204)	$ 1.204
Mar-12	$ 1.904	$ (1.529)	$ 1.529
Apr-12	$ 1.649	$ (1.785)	$ 1.785
May-12	$ 1.764	$ (1.670)	$ 1.670
Jun-12	$ 1.948	$ (1.486)	$ 1.486
Jul-12	$ 2.108	$ (1.325)	$ 1.325
Aug-12	$ 2.205	$ (1.229)	$ 1.229
Sep-12	$ 2.117	$ (1.317)	$ 1.317
Oct-12	$ 2.668	$ (0.766)	$ 0.766
Nov-12	$ 3.290	$ (0.144)	$ 0.144
Dec-12	$ 3.326	$ (0.108)	$ 0.108
Mean (Average of Column A)	**$ 3.43** (B)	**MAD**	**$ 0.71** (E) (Average of Column D)
		MAD (%)	**20.70%** (F) (E/B)

FEI WACOG (excluding hedging) MAD calculation
($/GJ)

	(A)	(C)	(D)
		(Column A minus B)	(Absolute Value of Column C)
Month	**WACOG**	**Deviation**	**Absolute Deviation**
Jan-12	$ 2.729	$ (0.283)	$ 0.283
Feb-12	$ 2.229	$ (0.783)	$ 0.783
Mar-12	$ 1.904	$ (1.108)	$ 1.108
Apr-12	$ 1.649	$ (1.363)	$ 1.363
May-12	$ 1.764	$ (1.248)	$ 1.248
Jun-12	$ 1.948	$ (1.064)	$ 1.064
Jul-12	$ 2.108	$ (0.904)	$ 0.904
Aug-12	$ 2.205	$ (0.807)	$ 0.807
Sep-12	$ 2.117	$ (0.895)	$ 0.895
Oct-12	$ 2.668	$ (0.344)	$ 0.344
Nov-12	$ 3.290	$ 0.277	$ 0.277
Dec-12	$ 3.326	$ 0.314	$ 0.314
Jan-13	$ 3.086	$ 0.074	$ 0.074
Feb-13	$ 3.090	$ 0.078	$ 0.078
Mar-13	$ 3.176	$ 0.164	$ 0.164
Apr-13	$ 3.392	$ 0.380	$ 0.380
May-13	$ 3.548	$ 0.536	$ 0.536
Jun-13	$ 3.467	$ 0.455	$ 0.455
Jul-13	$ 3.063	$ 0.051	$ 0.051
Aug-13	$ 2.650	$ (0.362)	$ 0.362
Sep-13	$ 2.518	$ (0.494)	$ 0.494
Oct-13	$ 2.803	$ (0.209)	$ 0.209
Nov-13	$ 3.295	$ 0.283	$ 0.283
Dec-13	$ 3.454	$ 0.442	$ 0.442
Jan-14	$ 3.809	$ 0.796	$ 0.796
Feb-14	$ 5.156	$ 2.144	$ 2.144
Mar-14	$ 5.423	$ 2.411	$ 2.411
Apr-14	$ 4.493	$ 1.480	$ 1.480
May-14	$ 4.474	$ 1.462	$ 1.462
Jun-14	$ 4.433	$ 1.421	$ 1.421
Jul-14	$ 4.280	$ 1.267	$ 1.267
Aug-14	$ 3.781	$ 0.769	$ 0.769
Sep-14	$ 3.674	$ 0.662	$ 0.662
Oct-14	$ 3.724	$ 0.712	$ 0.712
Nov-14	$ 3.581	$ 0.569	$ 0.569
Dec-14	$ 3.579	$ 0.567	$ 0.567
Jan-15	$ 2.958	$ (0.054)	$ 0.054
Feb-15	$ 2.511	$ (0.501)	$ 0.501
Mar-15	$ 2.421	$ (0.591)	$ 0.591
Apr-15	$ 2.294	$ (0.718)	$ 0.718
May-15	$ 2.393	$ (0.619)	$ 0.619
Jun-15	$ 2.490	$ (0.522)	$ 0.522
Jul-15	$ 2.419	$ (0.593)	$ 0.593
Aug-15	$ 2.404	$ (0.608)	$ 0.608
Sep-15	$ 2.422	$ (0.590)	$ 0.590
Oct-15	$ 2.219	$ (0.793)	$ 0.793
Nov-15	$ 2.081	$ (0.931)	$ 0.931
Dec-15	$ 2.085	$ (0.928)	$ 0.928
Mean	**$ 3.01** (B)	**MAD**	**$ 0.72** (E) (Average of Column D)
(Average of Column A)		**MAD (%)**	**23.95%** (F) (E/B)

57.3 Please calculate the mean absolute deviation for the CCRA rate for the period: (i) from 2009 to 2012; and (ii) from 2012 to 2015. How does the mean absolute deviation for the CCRA rate compare for the period: (i) from 2009 to 2012; and (ii) from 2012 to 2015? Please show your calculations.

Response:

Please refer to the response to BCUC IR 2.57.2.

57.4 Please calculate the mean absolute deviation for the WACOG for the period from January 1, 2005 to January 1, 2016. Please show your calculations.

Response:

Please refer to the response to BCUC IR 2.57.2.

57.5 Please calculate the mean absolute deviation for the WACOG for the period: (i) from 2009 to 2012; and (ii) from 2012 to 2015. How does the mean absolute deviation for the WACOG compare for the period: (i) from 2009 to 2012; and (ii) from 2012 to 2015?

Response:

Please refer to the response to BCUC IR 2.57.2.

57.6 Is there evidence to suggest whether the CCRA rate is more or less volatile pre-2012 than 2012 through 2015? What about the WACOG? Please explain in light of the annual customer bill impacts and mean absolute deviations.

Response:

Please refer to the responses to BCUC IRs 2.57.1.1 and 2.57.2.

57.7 With respect to BCUC IR 27.3, is the FEI statement based on studies/surveys or FEI's opinion? If applicable, please file the evidence.

Response:

FEI does not have any studies or surveys to directly support this statement. Instead, it relies on its experiences in speaking with customers on these topics on a daily basis. FEI often speaks to customers about the differences between their actual bill increase or decrease and information they may have received from other sources such as the media.

58.0 Reference: Exhibit B-8, AMPC to Concentric IR 1.1 to 1.6

Mr. Coyne's evidence and testimony

In a series of IRs, Mr. Coyne confirms in his responses that he had filed testimony in proceedings before the Alberta Utilities Commission and the Rėgie for Hydro Quebec Transmission and distribution.

58.1 In your response, please provide the letter of engagement where Mr. Coyne accepted to be the expert witness for FEI to provide testimony before the BCUC in the current application for FEI's Common Equity Component and Return on Equity for 2016.

Response:

A copy of the letter of engagement/retainer agreement is provided in Attachment 58.1. The document has been redacted to remove the hourly rates, given the commercial sensitivity of those rates from Concentric's perspective, and their limited relevance to the proceeding.

59.0 Reference: Exhibit B-1, Application, Appendix B, Evidence of Mr. James Coyne, pp. 70–71, 99;

Exhibit B-9, BCUC IR 24.1

Amalgamated FEI

On page 99 of Mr. Coyne's evidence in Appendix B of the Application, Mr. Coyne states: "Through amalgamation, FEI has increased its size but since it was already a large gas distributor, there has been no impact on FEI's risk profile due to the increased size of the amalgamated entity."

On pages 70-71 of Mr. Coyne's evidence, he also states:

> FEI attributed this decline to the higher capital costs associated with installation of natural gas heating relative to electricity and the prevalence of new multi-family dwellings that favor electricity in terms of installation economics. In its 2013 GCOC Decision, the Commission acknowledged that the province of BC provides relatively inexpensive hydro electricity and that the competitive position of natural gas to electricity is an existing risk which should be reviewed at each cost of capital proceeding.

FEI response to BCUC IR 24.1 indicates that the Lower Mainland 2015 residential operating cost in natural gas is 59 percent cheaper than electricity, which is an increase from 47 percent in 2012.

59.1 In Mr. Coyne's view, would it be reasonable to say that FEI's amalgamation and postage stamp rates may have a favourable impact on throughput, use per customer, and customer additions due to the addition of Vancouver Island customers?

Response:

Gas use is driven by a combination of the existing appliance stock, capital price differentials for gas vs. alternative fuels, fuel price differentials, income, household formation rates, household size and type, commercial and industrial growth, weather, and energy conservation initiatives. As a result it takes many years for existing customers to change their appliances using capital stock and usage levels. Mr. Coyne is aware that amalgamation and postage stamp rates will decrease rates for Vancouver Island and Whistler customers, with offsetting increases for Mainland customers, and these rate changes are being implemented over a three-year period, beginning in 2015. In terms of attracting new customers, Vancouver Island could potentially see greater rates of gas penetration over time, but these impacts must be considered against the corresponding potential loss on the Mainland due to higher rates from amalgamation. The rate change is greater for Vancouver Island than on the Mainland, but the load and market area are

also correspondingly larger on the Mainland. Because the rate changes are expected to be largely revenue neutral, one would not expect the net impacts on FEI's throughput, use per customer and customer additions to be material. (Also refer to FEI's response to BCUC IR 1.13.2 on this matter).

59.2 In Mr. Coyne's view, would it be reasonable to say that Vancouver Island customers may demand more natural gas service post-amalgamation as: (i) postage stamp rates resulting in lower natural gas costs; and (ii) wider price differential between natural gas vs. electricity in 2015 compared to 2012?

Response:

Please refer to Mr. Coyne's response to BCUC IR 2.59.1.

59.3 In Mr. Coyne's view, would it be reasonable to say that in Vancouver Island single family dwellings are more likely to install natural gas heating than multi-family dwellings?

Response:

It is Mr. Coyne's understanding that the historic single family housing capture rates on Vancouver Island and the Mainland are substantially higher than those for multi-family dwellings, so this would be a reasonable expectation. (Please also refer to the response to BCUC IR 2.59.3.1).

59.3.1 Please provide capture rates by housing type in Vancouver Island by condominium, townhouse, semi-detached, and single family. How does it compare to the Lower Mainland?

Response:

The requested information is provided below and is taken from the 2013 FortisBC Market Share study. The capture rate is the result of matching new gas customer attachments against the corresponding annual building or unit completions provided by BC Assessment.

Building Type	2013 Capture Rate Vancouver Island	2013 Capture Rate Vancouver
Single Family	51%	86%
Townhouse & Semi-Detached	41%	40%
Condo Buildings/Units	22% / 6%	22% / 2%

The capture rates are similar for townhouses and semi-detached homes as well as condo buildings for Vancouver and Vancouver Island. The capture rate for single family dwellings is lower on Vancouver Island which results in lower capture rate for amalgamated FEI in the same period.

Attachment 53.5

Additional Requested Data

	[1]	[2]	[3]	[3]	[4]	[5]	[6]	[7]
	Trade Weighted Index		Public Debt to GDP Ratio		Trading Surplus [millions]		Federal Budgets Surplus/Deficit [millions]	
	USD	CAN	Canada	U.S.	Can/ US	US/ Can	Canada	U.S.
1991			86.52%	65.33%		$ (5,914)	$ (32,319)	$ (67,500)
1992			91.29%	69.57%		$ (8,036)	$ (39,019)	$ (81,800)
1993		74.3	102.71%	70.60%		$ (10,772)	$ (38,530)	$ (56,300)
1994		72.9	101.41%	71.20%		$ (13,967)	$ (36,632)	$ (47,000)
1995	92.6	73.3	103.87%	68.29%		$ (17,144)	$ (30,006)	$ (36,100)
1996	97.4	75.0	109.40%	66.26%		$ (21,682)	$ (8,719)	$ (27,600)
1997	104.4	75.7	103.07%	61.66%	$ 30,509	$ (15,467)	$ 2,959	$ (700)
1998	115.9	72.9	101.62%	57.70%	$ 35,038	$ (16,653)	$ 5,779	$ 13,500
1999	116.2	73.3	92.24%	52.34%	$ 58,859	$ (32,111)	$ 14,258	$ 40,000
2000	119.5	74.1	84.20%	48.09%	$ 91,632	$ (51,897)	$ 19,891	$ 63,400
2001	126.0	72.3	85.66%	50.65%	$ 96,798	$ (52,844)	$ 8,048	$ 24,000
2002	126.9	71.4	84.78%	57.43%	$ 90,735	$ (48,165)	$ 6,621	$ (57,700)
2003	119.3	79.2	80.32%	58.78%	$ 87,559	$ (51,671)	$ 9,145	$ (99,600)
2004	113.8	83.7	76.47%	66.69%	$ 99,318	$ (66,480)	$ 1,463	$ (100,200)
2005	110.8	89.4	75.80%	66.83%	$ 107,871	$ (78,486)	$ 13,218	$ (80,100)
2006	108.7	95.1	74.87%	63.92%	$ 94,934	$ (71,782)	$ 13,752	$ (52,400)
2007	103.6	99.4	70.36%	64.33%	$ 84,511	$ (68,169)	$ 9,597	$ (47,100)
2008	99.9	97.4	74.73%	78.11%	$ 87,467	$ (78,342)	$ (5,755)	$ (207,400)
2009	105.6	93.9	87.38%	92.54%	$ 33,966	$ (21,591)	$ (55,598)	$ (330,700)
2010	101.8	102.0	89.52%	101.80%	$ 35,178	$ (28,380)	$ (33,372)	$ (318,700)
2011	97.1	105.0	93.06%	107.72%	$ 47,930	$ (34,033)	$ (26,279)	$ (312,600)
2012	99.9	105.1	95.92%	110.50%	$ 40,570	$ (31,613)	$ (18,415)	$ (265,000)
2013	101.0	101.9	92.33%	109.21%	$ 44,624	$ (31,803)	$ (5,150)	$ (140,100)
2014	104.1	96.1	94.82%	110.12%	$ 49,026	$ (35,377)	$ 1,911	$ (121,600)
2015	117.3	86.6	N/A	N/A	N/A	$ (12,586)	N/A	N/A
25-year Avg.	--	--	89.68%	73.74%	$ 67,585	$ (36,199)	$ (9,298)	$ (96,221)
10-year Avg.	103.91	98.25	85.89%	93.14%	$ 57,579	$ (41,367)	$ (13,257)	$ (199,511)
5-year Avg.	103.87	98.95	94.03%	109.39%	$ 45,537	$ (29,082)	$ (11,983)	$ (209,825)
Correlation	-0.56		0.16		-0.91		0.55	

[1] Source: Economic Research Federal Reserve Bank of St. Louis, "FRED Economic Date", Not Seasonally Adjusted, Annual, Average, https://research.stlouisfed.org/fred2/series/TWEXB

[2] Source: Bloomberg, MSCECATW Index, Morgan Stanley Canada Trade Weighted Index, Monthly Average, Averaged to Annual

[3] Source: Finance Canada, 2015 Fiscal Reference Tables, "government gross financial liabilities/ percent of GDP", http://www.fin.gc.ca/frt-trf/2015/frt-trf-15-eng.aspOctober 2014,

[4] Source: Statistics Canada. CANSIM Table: 228-0069, - Merchandise imports, exports and trade balance, customs and balance of payments basis for all countries, by seasonal adjustment and principal trading partners, annual (dollars), http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/gblec02a-eng.htm

[5] Source: United States Census Bureau, https://www.census.gov/foreign-trade/balance/c1220.html#questions

[6] Source: Finance Canada, 2015 Fiscal Reference Tables, http://www.fin.gc.ca/frt-trf/2015/frt-trf-15-eng.asp

[7] Source: Economic Research Federal Reserve Bank of St. Louis, "FRED Economic Date", Not Seasonally Adjusted, https://research.stlouisfed.org/fred2/series/M318501Q027NBEA#

Attachment 53.5.1

Canadian & U.S. Macroeconomic Factors

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[11]	[12]	[13]	[14]
	Total Return on:		Total Return on:		Real GDP Growth		CPI		10-year Gov't Bond		Exports		Unemployment		Currency
	S&P/TSX	S&P 500	S&P/TSX Utilities	S&P 500 Utilities	Canada	U.S.	Canada	U.S.	Canada	U.S.	Canada to U.S./ Canadian GDP	U.S. to Canada / U.S. GDP	Canada	U.S.	Exchange Rate (CAD / USD)
1991	12.02	30.47	--	--	-2.1	-0.2	5.6	4.2	9.42	7.86	15.55	1.86	9.8	6.8	1.15
1992	-1.43	7.62	--	--	0.9	3.4	1.4	3.0	8.05	7.01	17.28	2.10	10.7	7.5	1.21
1993	32.55	10.08	--	--	2.6	2.9	1.9	3.0	7.22	5.87	20.04	2.51	10.8	6.9	1.29
1994	-0.18	1.32	--	--	4.6	4.1	0.1	2.6	8.42	7.09	22.95	3.00	9.6	6.1	1.37
1995	14.53	37.58	--	--	2.7	2.5	2.2	2.8	8.08	6.57	24.82	3.19	8.6	5.6	1.37
1996	28.35	22.96	--	--	1.7	3.7	1.5	3.0	7.20	6.44	25.94	3.13	8.8	5.4	1.36
1997	14.98	33.36	--	--	4.3	4.5	1.7	2.3	6.11	6.35	26.82	3.51	8.4	4.9	1.38
1998	-1.58	28.58	--	--	4.2	4.4	1.0	1.6	5.30	5.26	28.67	3.94	7.7	4.5	1.48
1999	31.71	21.04	--	--	5.2	4.8	1.8	2.2	5.55	5.65	30.75	3.96	7.0	4.2	1.49
2000	7.41	-9.11	--	--	5.1	4.1	2.7	3.4	5.89	6.03	32.57	3.97	6.1	4.0	1.49
2001	-12.57	-11.89	--	--	1.7	1.1	2.5	2.8	5.47	5.02	30.90	3.82	6.5	4.7	1.55
2002	-12.44	-22.10	--	--	2.8	1.8	2.2	1.6	5.29	4.61	29.26	3.76	7.0	5.8	1.57
2003	26.72	28.68	24.96	26.27	2.0	2.5	2.8	2.3	4.79	4.01	26.34	3.02	6.9	6.0	1.40
2004	14.48	10.88	9.42	24.28	3.2	3.5	1.8	2.7	4.59	4.27	26.36	2.74	6.4	5.5	1.30
2005	24.13	4.91	38.30	16.83	3.1	3.1	2.2	3.4	4.05	4.29	26.01	2.49	6.0	5.1	1.21
2006	17.26	15.79	7.01	21.00	2.7	2.7	2.0	3.2	4.22	4.80	24.23	2.25	5.5	4.6	1.13
2007	9.83	5.49	11.80	19.38	2.1	1.9	2.2	2.8	4.28	4.63	22.64	2.07	5.2	4.6	1.07
2008	-33.00	-37.00	-20.46	-28.98	1.1	-0.3	2.3	3.8	3.58	3.66	22.41	2.10	5.3	5.8	1.07
2009	35.05	26.46	19.00	11.92	-2.8	-3.1	0.3	-0.4	3.29	3.26	17.25	1.93	7.3	9.3	1.14
2010	17.61	15.06	18.42	5.46	3.2	2.4	1.8	1.6	3.20	3.22	17.75	1.85	7.1	9.6	1.03
2011	-8.71	2.10	6.47	19.95	2.6	1.8	2.9	3.2	2.78	2.78	18.72	1.84	6.5	8.9	0.99
2012	7.19	16.00	4.00	0.47	1.8	2.2	1.5	2.1	1.85	1.80	18.59	1.89	6.3	8.1	1.00
2013	12.98	32.39	-3.71	14.79	2.0	2.2	0.9	1.5	2.26	2.35	19.63	1.79	7.1	7.4	1.03
2014	10.55	13.68	16.08	28.98	2.5	2.4	2	1.6	2.23	2.53	22.37	1.79	6.7	6.2	1.10
2015	-14.30	-5.63	-12.93	-6.58	N/A	N/A	N/A	N/A	1.52	2.14	N/A	N/A	N/A	N/A	1.28
25-year Avg.	9.33	11.15			2.38	2.43	1.97	2.51	4.99	4.70	23.66	2.69	7.39	6.14	1.26
10-year Avg.	5.45	8.43	4.57	8.64	1.69	1.36	1.77	2.16	2.92	3.12	20.40	1.95	6.33	7.16	1.08
5-year Avg.	1.54	11.71	1.98	11.52	2.23	2.15	1.83	2.10	2.13	2.32	19.83	1.83	6.65	7.63	1.08
Correlation	0.71		0.69		0.87		0.63		0.97		0.90		0.22		--
Consensus Forecasts [15]															
2015					1.10	2.50	1.20	0.20	1.70	2.30			6.90	5.30	1.28
2016					2.00	2.60	2.00	1.80	2.10	2.70			6.80	4.80	1.26
2017					2.20	2.50	2.00	2.20	3.00	3.50					1.20
2018					2.20	2.50	2.00	2.40	3.50	3.80					

Notes:

[1] Source: Morningstar and Bloomberg Professional; includes price appreciation and dividend yield

[2] Source: Morningstar and Bloomberg Professional; includes price appreciation and dividend yield

[3] Source: Bloomberg Professional; includes price appreciation and dividend yield, however dividend data for S&P/TSX Utilities not available prior to 2003

[4] Source: Bloomberg Professional; includes price appreciation and dividend yield

[5] Source: Statistics Canada; expenditure-based GDP at market prices, chained 2007 prices, seasonally adjusted

[6] Source: U.S. Bureau of Economic Analysis

[7] Source: Statistics Canada; not seasonally adjusted

[8] Source: U.S. Bureau of Labor Statistics; not seasonally adjusted, U.S. city average, all items

[9] Source: Bank of Canada, Daily, Average, Annual, http://www.bankofcanada.ca/rates/interest-rates/lookup-bond-yields/

[10] Source: Bloomberg Professional

[11] Source: Government of Canada (exports to United States, merchandise only), Office of the United States Trade Representative (exports to Canada, merchandise only), United States Census Bureau (Trade in Goods with Canada), The World Bank (Total GDP), U.S. Bureau of Economic Analysis (U.S. GDP)

[12] Source: 1989-2012: U.S. Bureau of Labor Statistics, International Unemployment Rates and Employment Indexes, Seasonally Adjusted, 2013: Statistics Canada

[13] Source: U.S. Bureau of Labor Statistics, International Unemployment Rates and Employment Indexes, Seasonally Adjusted

[14] Source: Federal Reserve Economic Data

[15] Source: Consensus Forecasts, Survey Date October 12, 2015

FortisBC Energy Inc.

Canadian & U.S. Bond Yield Averages
January 2008 - December 2015

Line No.			[A] Gov of Canada 30-Year T-Bonds	[B] Canadian Average Corporate A	[C] Canadian Public Utility Bonds A-Rated	[D] Canadian Public Utility Bonds BBB-Rated	[E] Utility Bond ($U.S.) BBB+-Rated	[F] Canadian Credit Spreads A-Rated	[G] Canadian Credit Spreads BBB-Rated	[H] U.S. Credit Spread BBB+-Rated
1	2008	JAN	4.11	5.43	5.37	5.80	6.11	1.27	1.69	2.00
2		FEB	4.19	5.57	5.53	5.87	6.22	1.34	1.67	2.03
3		MAR	4.01	5.42	5.38	5.74	6.24	1.37	1.73	2.23
4		APR	4.11	5.58	5.56	5.88	6.24	1.45	1.77	2.13
5		MAY	4.09	5.47	5.50	5.76	6.26	1.41	1.67	2.17
6		JUN	4.13	5.50	5.57	5.88	6.36	1.44	1.74	2.23
7		JUL	4.10	5.54	5.59	5.93	6.40	1.49	1.82	2.29
8		AUG	4.04	5.59	5.58	5.88	6.41	1.54	1.84	2.38
9		SEP	4.03	5.85	5.81	6.01	6.31	1.78	1.98	2.29
10		OCT	4.18	6.50	6.39	6.73	6.86	2.21	2.56	2.68
11		NOV	4.13	6.89	6.78	7.04	7.85	2.64	2.91	3.72
12		DEC	3.62	6.98	6.58	6.84	7.16	2.97	3.23	3.55
13	2009	JAN	3.62	7.22	6.62	6.99	6.62	3.00	3.37	3.00
14		FEB	3.68	6.99	6.65	6.89	6.89	2.97	3.22	3.21
15		MAR	3.63	6.71	6.57	6.80	7.24	2.95	3.18	3.61
16		APR	3.70	6.68	6.45	6.75	7.46	2.76	3.06	3.77
17		MAY	3.93	6.64	6.30	6.62	7.20	2.37	2.69	3.27
18		JUN	3.96	6.27	5.86	6.20	6.75	1.91	2.25	2.79
19		JUL	3.96	6.07	5.65	6.01	6.44	1.70	2.05	2.49
20		AUG	3.95	5.77	5.43	5.72	5.98	1.47	1.76	2.03
21		SEP	3.89	5.62	5.30	5.59	5.75	1.41	1.70	1.85
22		OCT	3.93	5.70	5.35	5.59	5.86	1.42	1.66	1.93
23		NOV	3.94	5.68	5.36	5.60	5.94	1.42	1.65	1.99
24		DEC	4.01	5.75	5.50	5.75	6.05	1.49	1.74	2.04
25	2010	JAN	4.05	5.76	5.46	5.78	5.96	1.41	1.73	1.90
26		FEB	4.04	5.72	5.43	5.77	6.04	1.39	1.73	2.01
27		MAR	4.06	5.69	5.39	5.68	6.00	1.33	1.61	1.94
28		APR	4.07	5.54	5.35	5.59	5.96	1.28	1.51	1.89
29		MAY	3.83	5.41	5.29	5.45	5.62	1.46	1.62	1.78
30		JUN	3.74	5.34	5.31	5.47	5.62	1.57	1.73	1.88
31		JUL	3.73	5.28	5.23	5.41	5.45	1.50	1.68	1.71
32		AUG	3.57	5.14	5.06	5.23	5.15	1.49	1.66	1.58
33		SEP	3.48	5.09	5.02	5.13	5.18	1.54	1.65	1.70
34		OCT	3.44	4.99	4.93	5.05	5.32	1.50	1.61	1.88
35		NOV	3.58	5.06	4.99	5.11	5.65	1.41	1.53	2.07
36		DEC	3.62	5.15	5.04	5.22	5.85	1.42	1.60	2.24
37	2011	JAN	3.68	5.14	5.07	5.27	5.90	1.39	1.59	2.22
38		FEB	3.80	5.19	5.15	5.33	5.90	1.35	1.53	2.10
39		MAR	3.74	5.15	5.10	5.24	5.77	1.36	1.51	2.03
40		APR	3.76	5.18	5.16	5.30	5.76	1.40	1.54	2.00
41		MAY	3.57	5.00	5.00	5.11	5.54	1.43	1.54	1.97
42		JUN	3.46	4.91	4.91	4.98	5.57	1.45	1.52	2.11
43		JUL	3.41	4.83	4.84	4.94	5.58	1.44	1.53	2.18
44		AUG	3.08	4.57	4.58	4.69	5.03	1.50	1.62	1.96

45		SEP	2.85	4.47	4.46	4.56	4.75	1.60	1.70	1.90
46		OCT	2.90	4.54	4.53	4.60	4.82	1.62	1.70	1.91
47		NOV	2.73	4.38	4.33	4.42	4.69	1.59	1.69	1.96
48		DEC	2.56	4.27	4.15	4.24	4.76	1.59	1.69	2.20
49	2012	JAN	2.56	4.13	4.04	4.11	4.68	1.48	1.55	2.12
50		FEB	2.61	4.01	4.01	4.07	4.56	1.39	1.46	1.95
51		MAR	2.67	4.05	4.04	4.07	4.62	1.37	1.40	1.95
52		APR	2.62	4.03	4.00	4.11	4.54	1.38	1.49	1.91
53		MAY	2.46	3.94	3.95	4.08	4.31	1.49	1.63	1.85
54		JUN	2.33	3.88	3.91	4.03	4.17	1.58	1.70	1.84
55		JUL	2.27	3.83	3.82	3.94	4.00	1.55	1.67	1.73
56		AUG	2.38	3.88	3.86	3.99	4.04	1.48	1.61	1.66
57		SEP	2.41	3.89	3.87	3.97	4.04	1.46	1.56	1.63
58		OCT	2.41	3.85	3.85	3.95	3.99	1.45	1.54	1.58
59		NOV	2.33	3.77	3.81	3.87	3.91	1.48	1.55	1.58
60		DEC	2.36	3.76	3.82	3.87	4.06	1.46	1.51	1.70
61	2013	JAN	2.50	3.86	3.90	3.97	4.20	1.40	1.47	1.70
62		FEB	2.60	3.96	3.99	4.11	4.24	1.40	1.52	1.65
63		MAR	2.55	3.92	3.95	4.07	4.26	1.40	1.52	1.71
64		APR	2.40	3.76	3.81	3.91	4.06	1.41	1.51	1.66
65		MAY	2.53	3.87	3.91	4.00	4.22	1.38	1.48	1.70
66		JUN	2.77	4.10	4.13	4.22	4.59	1.36	1.45	1.83
67		JUL	2.93	4.27	4.31	4.43	4.74	1.39	1.50	1.81
68		AUG	3.09	4.42	4.48	4.58	4.82	1.39	1.49	1.73
69		SEP	3.19	4.59	4.67	4.74	4.91	1.48	1.55	1.72
70		OCT	3.09	4.52	4.56	4.64	4.87	1.47	1.55	1.77
71		NOV	3.13	4.53	4.55	4.61	4.97	1.42	1.48	1.84
72		DEC	3.22	4.61	4.61	4.68	4.97	1.39	1.47	1.75
73	2014	JAN	3.08	4.45	4.43	4.52	4.77	1.35	1.44	1.68
74		FEB	3.01	4.37	4.36	4.46	4.63	1.35	1.46	1.63
75		MAR	2.97	4.31	4.29	4.39	4.63	1.32	1.42	1.66
76		APR	2.96	4.23	4.22	4.33	4.54	1.26	1.37	1.58
77		MAY	2.85	4.22	4.18	4.27	4.40	1.33	1.42	1.55
78		JUN	2.83	4.22	4.18	4.25	4.44	1.34	1.42	1.61
79		JUL	2.74	4.12	4.09	4.15	4.36	1.34	1.41	1.62
80		AUG	2.62	4.04	4.01	4.08	4.34	1.39	1.46	1.72
81		SEP	2.70	4.11	4.09	4.17	n/a	1.39	1.47	n/a
82		OCT	2.56	4.00	3.98	4.05	n/a	1.42	1.50	n/a
83		NOV	2.57	4.03	4.01	4.11	4.36	1.44	1.55	1.79
84		DEC	2.40	3.90	3.86	3.98	4.27	1.47	1.58	1.88
85	2015	JAN	2.11	3.63	3.59	3.71	3.86	1.48	1.60	1.75
86		FEB	2.01	3.50	3.46	3.61	3.88	1.46	1.61	1.88
87		MAR	2.05	3.50	3.46	3.58	3.94	1.41	1.53	1.89
88		APR	2.04	3.49	3.45	3.65	3.92	1.41	1.61	1.88
89		MAY	2.34	3.82	3.78	4.04	4.35	1.44	1.70	2.01
90		JUN	2.38	3.93	3.89	4.15	4.60	1.51	1.78	2.23
91		JUL	2.24	3.92	3.89	4.14	4.60	1.65	1.90	2.36
92		AUG	2.11	3.92	3.89	4.20	4.47	1.78	2.09	2.36
93		SEP	2.24	4.11	4.07	4.42	4.60	1.83	2.18	2.36
94		OCT	2.26	4.18	4.14	4.49	4.50	1.88	2.22	2.24
95		NOV	2.35	4.22	4.17	4.60	4.66	1.82	2.25	2.31
96		DEC	2.19	4.08	4.05	4.41	4.64	1.85	2.21	2.45

Note: September and October 2014 Utility Bond ($U.S.) BBB+-Rated is n/a due to Bloomberg data unavailability.

Sources:

[A] Bloomberg, Canadian Government Generic 30-Year Treasury Bond

[B] Bloomberg, Canadian Corporate (A) Average Bond Index

[C] Bloomberg, Canadian A-Rated Utility Bond Index

[D] Bloomberg, Canadian BBB-Rated Utility Bond Index

[E] Bloomberg, USD BBB+-Rated Utility Bond Index

[F] Equals [C] − [A]

[G] Equals [D] − [A]

[H] Equals [E] - [A]

Attachment 58.1

~~CONFIDENTIAL~~

October 28, 2014

Ms. Ilva Bevacqua
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, British Columbia
V4N 0E8

RE: REGULATORY SUPPORT 2016 COST OF CAPITAL FILING

Dear Ms. Bevacqua,

Concentric Energy Advisors, Inc. ("Concentric") appreciates the opportunity to provide this proposal to FortisBC Energy Inc. ("FEI", "Fortis", or the "Company") to assist in the development of its anticipated filings on cost of capital related matters for consideration by the British Columbia Utilities Commission ("BCUC" or "Commission").

We understand the Company plans to file an updated cost of capital for its 2016 rate year by the end of the first quarter of 2015. The filing should contain an updated Return on Equity ("ROE"), assessment of the Company's business risk, and recommended capital structure. In addition, the assessment may also consider the application of an automatic adjustment mechanism ("AAM") for setting the ROE on an annual basis.

SCOPE OF SERVICES

Concentric will serve as the lead cost of capital expert for the Company and provide expert services relative to cost of capital matters including ROE, business risk, capital structure and, if required, AAM, for establishing utility equity returns. It is understood that FEI wishes to retain Concentric as an independent expert to reach its own conclusions on the subject matter of this retainer. That is, Concentric will not be acting as an advocate of particular positions pre-determined by FEI.

A. Tasks and Approach

Concentric proposes to meet Fortis' specified needs with an approach that relies on a combination of our ongoing research into North American cost of capital decisions and methodologies, review of past evidence filed with the BCUC and resulting decisions, our considerable experience in BC and across Canada in cost of capital proceedings, and our models and databases that provide us with the tools to respond in a cost-effective and authoritative manner. We propose the following approach to addresses the Company's evidentiary requirements for the 2016 rate filing:

1. North American Cost of Capital Review

Concentric researches and tracks cost of capital decisions in Canada and the U.S., and maintains a database extending back to the year 2000 for Canadian gas and electric utilities. This data is summarized and now published on a periodic basis, with support from the Canadian Gas Association. This research work is updated through May 2014, and we would check for any new decisions, and summarize the results in the evidence, with particular attention to recent Canadian decisions and representative U.S. decisions.

2. FEI's Business Risk

Concentric understands that FEI's business risk profile was last considered by the Commission in the 2013 GCOC Stage 1 proceeding, where the Commission concluded that FEI (in its pre-amalgamation state) would continue to serve as the "benchmark utility". In the GCOC Stage 1 Decision, the BCUC established the allowed cost of capital for FEI, including a deemed common equity ratio of 38.5% and an allowed ROE for 2013 of 8.75%. For the 2016 filing, Concentric will

- evaluate the change in risk since the time of the last comprehensive review of business risk,
- provide an overall comparative assessment of the relative business risk of FEI relative to select peers,
- consider the impact of amalgamation of the FortisBC Energy utilities on the overall business risk of the amalgamated FEI, and also
- consider any fundamental changes to the business risk profile of FEI that are anticipated in the near term.

Concentric's business risk analysis will contain the following elements, with qualitative and quantitative analysis as appropriate. We address risk from three perspectives (financial risk, business risk, and regulatory risk), designed to reflect an investor's perspective on utility risk.

Financial Risk Factors, such as

- Capital Structure
- Credit metrics
- Capital market changes
- Credit ratings

Business Risk Factors, such as

- Gas supply risk
- Gas price levels and volatility
- Competiveness of gas to alternate energy sources
- Market share and market trends

- Changes in customer mix
- Large customer exposure
- Macroeconomic trends in the Province and service area
- Changes in codes and standards impacting competiveness and operations
- Infrastructure risks
- Operating risks
- Longer term industry risks

Regulatory Risk Factors, such as

- Federal or provincial policy mandates (including DSM programs, clean air and greenhouse gas regulations, carbon tax, retail competition, etc.)
- Volume/demand Risk (including mechanisms to decouple volume from cost recovery)
- Cost recovery provisions (including both capital and operating costs)
- Form of rate regulation (including an examination of the principal features of the PBR plan approved by the Commission in Order G-138-14 on September 15, 2014.)
- Regulatory lag

In addition to the specific factors listed above, Concentric will examine any other factors that it considers to be relevant to the assessment of risk.

In addition, Concentric will examine the impacts of amalgamation of FEI, FortisBC Energy (Vancouver Island) Inc. ("FEVI"), and FortisBC Energy (Whistler) Inc. ("FEW"), (collectively FortisBC Energy Utilities or "FEU") on financial, business and regulatory risk. That is, Concentric will compare the amalgamated FEI to pre-amalgamation FEI.

While the primary focus will be the change in FEI's risk since 2012, Concentric believes the relative risk of FEI in contrast to its industry peers should also be considered. This risk analysis must be done at the operating company level to properly assess relative utility business and financial risk. We would anticipate using a group of Canadian gas distributors, and a low risk group of U.S. comparators. Concentric would identify those companies most suitable for relative risk analysis based on characteristics of the utility and its service area. This research would be conducted using publicly available information. In total, Concentric would conduct risk analysis on a total of approximately 10 Canadian and U.S. companies. We believe this would be of sufficient size to derive meaningful conclusions. The risk factors considered would be comparable to those identified above.

Finally, Concentric will compare FEI (amalgamated at the FEU level) to other BC utilities to ensure it remains appropriately characterized as the benchmark utility.

3. ROE Analysis

Utilizing the Canadian and U.S. proxy companies identified above, Concentric will estimate the cost of equity for FEI using three alternative models:

- Discounted Cash Flow (DCF)
- Capital Asset Pricing Model (CAPM)
- Risk Premium Model

Inputs for each model will be developed from the groups of Canadian and U.S. utilities identified above, and appropriate macroeconomic indicators (e.g., the risk free rate, and GDP growth).

The results of the ROE analysis in conjunction with the risk assessment conducted above will determine the recommended ROE for FEU.

4. Common Equity Ratio

Based on a combination of the risk analysis and ROE analysis conducted above, Concentric will develop the appropriate common equity ratio for the amalgamated FEI. This assessment will be based upon an evaluation of:

- The Commission's previous findings concerning FEI's common equity ratio, and those of FEVI and FEW as applicable
- The absolute and relative risk of FEU in relation to its Canadian and U.S. peers
- Capital structures of the Canadian and U.S. proxy group companies supporting the ROE analysis
- Credit metrics
- The evidence filed in the Company's Common Rates, Amalgamation And Rate Design Application, and the Commission's decision regarding capital structure

5. Consultation and Hearings

Based on the analysis resulting from the above tasks, Concentric will draft expert testimony summarizing its research, conclusions and recommendations, and be prepared to present these findings to stakeholders and before the Commission. These activities will be responsive to the Commission's process and Fortis' determinations regarding participation. Concentric will be specifically available to:

- Present a summary of its work to stakeholders, Commission and Staff (in PowerPoint format)
- Respond to interrogatories and undertakings
- Review the work of other witnesses and develop interrogatories as required

- Appear as a witness in formal hearings
- Assist with briefs and additional comments as necessary.

B. Process, Report and Timeline

1. Research, Analysis and Communications Process

Concentric's research and analysis will be based to a large extent on our existing models, databases, and prior and current research on the cost of capital for Canadian and U.S. utilities. These models and databases will be updated from public and proprietary sources such as:

- SNL/Regulatory Research Associates database of U.S. regulatory decisions
- Concentric's database of Canadian cost of capital decisions
- Credit rating reports from the major rating agencies
- Stock prices, dividends, bond yields from Bloomberg
- Earnings growth rates from Bloomberg, Yahoo! Finance, Zacks, Thomson, and Value Line
- Projected bond yields and GDP growth rates from Consensus Forecasts
- Capital market reports from the central banks in Canada and the U.S.
- Annual reports, regulatory filings and tariffs for profiled utilities
- U.S., Canadian, Provincial and State level data on fuel prices and markets
- Supporting internet research

2. Evidence Content and Structure

Concentric anticipates the evidence would follow the general outline presented below:

Introduction and Overview
Determination of a Fair Return (discussion of the Fair Return Standard)
Continuance of FEI as Benchmark Utility
North American Capital Markets
Review of Canadian and U.S Gas and Electric Cost of Capital Decisions Since 2012
Cost of Capital Analysis
    Proxy Group Selection
    ROE Analysis (DCF, CAPM, Risk Premium)
    Summary of Results
Risk Analysis
    Changes in Fortis' Risk Profile
    Fortis' Risk in Comparison to Canadian and U.S. Gas Distributors
    Credit Metrics
    Effects of Amalgamation
Capital Structure
    Financial theory

- The importance of an appropriate equity ratio
- Regulatory treatment of capital structure in BC
- Appropriate capital structure

Automatic Adjustment Mechanism (if necessary)
Conclusions and Recommendations
Schedules and Attachments

- Resume(s)
- Risk Profiles and Analysis
- ROE Results
- Capital Market Charts and Analysis
- Related Supporting Documentation

PROJECT TEAM

In additional to being a member of our team, I, James Coyne, will serve as the Responsible Officer and ROE testifying expert for the engagement and oversee the project in its entirety.

> **James M. Coyne, Senior Vice President,** is an industry expert who provides financial, regulatory, strategic, and litigation support services to clients in the power and gas utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, cross-border trade, rate and regulatory policy, capital cost determinations, valuations, fuels, and power markets. He is a frequent speaker and author of numerous articles on the energy industry and regularly provides expert testimony before federal, state, and provincial jurisdictions in the U.S. and Canada. He testifies on matters pertaining to the cost of capital, capital structure, business risk, alternative ratemaking mechanisms and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

I will draw primarily on the expertise of the following individuals who have a unique understanding of cost of capital, risk analysis, and Canadian regulation and will also draw upon additional consulting and administrative staff in order to complete this assignment in a high quality and cost-effective manner.

John P. Trogonoski, Senior Project Manager, is a financial and economic consultant with over 20 years of experience in utility regulation, financial analysis, business valuation, property taxation, and program administration. Since joining Concentric in 2008, Mr. Trogonoski has assisted clients with a variety of regulatory matters including drafting expert testimony and reports on cost of capital and business and financial risk analysis. As a member of the Staff of the Colorado Public Utilities Commission, Mr. Trogonoski supervised the financial analysts in the energy and telecommunications sections and filed expert testimony on rate of return, revenue requirement, cost allocation, rate design, incentive regulation, and policy matters. He has a Master's degree in Business Administration and an undergraduate degree in Marketing from the University of Colorado at Denver.

Julie Lieberman, Project Manager, is a financial and economic consultant with over 25 years of experience in the energy industry. Her broad base of experience includes: financial and economic consulting in the energy sector, risk management, asset valuation and modeling, wholesale and retail energy trading and operations, energy procurement and scheduling, hedging strategies, regulatory policy and compliance, utility ratemaking, due diligence and litigation support and analysis. She has performed a variety of economic analyses, extensive regulatory research and assisted in the preparation of testimony and research reports in both regulatory and non-regulatory proceedings. Ms. Lieberman has performed focused regulatory research on Dodd Frank legislation and its implications for the energy sector, with a particular concentration on the regulated end-user segment. Ms. Lieberman is proficient in Microsoft Office applications, Crystal Ball, and SPSS and has used option modeling, Monte Carlo simulations, and VAR analysis in a variety of risk applications. Prior to joining Concentric, Ms. Lieberman served in the financial and risk related fields in the unregulated energy trading and marketing sector. She holds a Masters in Finance from Boston College, a B.S. in Accounting from Indiana University, is a licensed CPA (Texas), and is a FINRA licensed securities professional (Series 7, 63, and 79).

TERMS AND BUDGET

Concentric proposes to perform these tasks on a time and materials basis at Concentric's standard hourly rates, provided in Attachment A for 2014. We will provide monthly invoices reporting all hours worked and expenses as we proceed, and any changes in scope or the workplan will be discussed in advance.

CONCLUSION

We appreciate the opportunity to work with Fortis on this important assignment. Please contact me at 508.263.6255 at your earliest convenience with any questions you may have regarding our proposal letter or to discuss next steps.

Sincerely,

CONCENTRIC ENERGY ADVISORS, INC.

Jim Coyne
Senior Vice President
293 Boston Post Rd. West, Suite 500
Marlborough, MA 01752
508.263.6255
jcoyne@ceadvisors.com

Attachments:

A. Concentric's Hourly Rate Schedule
B. Concentric's Standard Terms and Conditions

CONCENTRIC ENERGY ADVISORS, INC.
HOURLY RATE SCHEDULE

TITLE	HOURLY RATE
CHAIRMAN AND CHIEF EXECUTIVE OFFICER	[redacted]
SENIOR VICE PRESIDENT	
VICE PRESIDENT, EXECUTIVE ADVISOR	
ASSISTANT VICE PRESIDENT	
SENIOR PROJECT MANAGER	
PROJECT MANAGER	
SENIOR CONSULTANT	
CONSULTANT	
ASSISTANT CONSULTANT	
ANALYST	
ASSOCIATE	
PROJECT ASSISTANT	

CONCENTRIC ENERGY ADVISORS, INC.
STANDARD TERMS AND CONDITIONS

1. *Scope* – Concentric Energy Advisors, Inc. ("Concentric") will perform the services set forth in the Letter or Proposal of which these Terms and Conditions (Terms) are a part. The provisions of these Terms shall control in the case of conflict with any provisions of the Letter or Proposal.

2. *Fees and Expenses* – Unless otherwise stated, fees for services by Concentric shall be based upon the rates, at the time the work is performed, of the personnel actually involved in the assignment. Report production and printing, reproduction, and telephone charges will be billed to you at Concentric's standard charges for such materials for services. Expenses of consultants while on assignment or any other charge incurred or expenditure made on your behalf will be charged at our cost.

3. *Payment* – Concentric will submit monthly invoices reflecting actual work performed and expenses incurred. Payment shall be due in U.S. funds 30 days after the date of an invoice. Amounts past due more than 30 days shall bear interest at an annual rate of 12% from the due date until payment is received.

4. *Sales Tax* – You are responsible for paying any local, state, or federal sales, use, or ad valorem tax that might be assessed on our services.

5. *Independent Contractor* – It is understood and agreed that Concentric shall for all purposes be an independent contractor, shall not hold itself out as representing or acting in any manner for you, and shall have no authority to bind you to any contract or in any other manner.

6. *Termination* – These terms shall be subject to the right of either party to terminate at any time upon not less than ten (10) days prior written notice to the other party. Upon termination, you shall pay the full amount due for services rendered and costs and expenses incurred and not paid for up to that time, and the costs of returning consultant personnel to home base and other reasonable costs and expenses incurred in effecting termination and returning documents.

7. *Responsibility Statement* – Concentric agrees that the services provided for herein will be performed in accordance with recognized professional consulting standards for similar services and that adequate personnel will be assigned for that purpose. If, during the performance of these services or within six months following completion of the assignment, such services shall prove to be faulty or defective by reason of a failure to meet such standards, Concentric agrees that upon prompt written notification from you prior to the expiration of the six month period following the completion of the assignment containing any such fault or defect, such faulty portion of the services shall be redone at no cost to you up to a maximum amount equivalent to the cost of the services rendered under this assignment. The foregoing shall constitute Concentric's sole liability with respect to the accuracy or completeness of the work and the activities involved in its preparation. In no event shall Concentric, its agents, employees, or others providing materials or performing services in connection with work on this assignment be liable

for any direct, consequential or special loss or damage, whether attributable to breach of contract, tort, including negligence, or otherwise; and except as herein provided, you release, indemnify, and hold Concentric, its agents, employees, or others providing materials or performing services in connection with work on this assignment harmless from any and all liability including costs of defense, settlement and reasonable attorney's fees.

8. *Work Product* – Any report or other document prepared pursuant to these Terms shall be for your use only. Concentric's prior written consent is required for the use of (or reference to) its report or any other document prepared pursuant to these Terms in connection with a public offering of securities or in connection with any other financing. Concentric hereby agrees, however, to the Client's reference to the work product in connection with any proxy relating to a combination between two parties. It is understood and agreed that Concentric's use of its proprietary computer software, methodology, procedures, or other proprietary information in connection with an assignment shall not give you any rights with respect to such proprietary computer software, methodology, procedures or other proprietary information. Concentric may retain and further use the technical content of its work hereunder.

9. *Excused Performance* – Concentric shall not be deemed in default of any provision hereof or be liable for any delay, failure in performance, or interruption of service resulting directly or indirectly from acts of God, civil or military authority, civil disturbance, war, strikes or other labor disputes, fires, other catastrophes, or other forces beyond its reasonable control, whether or not such event may be deemed foreseeable.

10. *Related Litigation* – In the event that Concentric employees (current or former), subcontractors or agents are compelled to provide testimony, produce documents, or otherwise incur costs or expend time in any legal proceeding related to Concentric's work for you, you agree to reimburse Concentric at its regular billing rate per hour for its time expended, and for any expenses incurred (at Concentric's direct cost).

11. *Notices* – All notices given under or pursuant to the Terms shall be sent by Certified or Registered Mail, Return Receipt Requested, and shall be deemed to have been delivered when physically delivered if to Concentric Energy Advisors, Inc., 293 Boston Post Road West, Suite 500, Marlborough, MA 01752, Attention Mr. John J. Reed, Chairman and Chief Executive Officer, and if to you at the address shown on the Letter or Proposal of which these Terms are a part or such other address as you may designate by written notice to us.

12. *Complete Agreement* – It is understood and agreed that these Terms and the Letter or Proposal of which they are a part embody the complete understanding of the parties and that any and all provisions, negotiations and representations not included herein are hereby abrogated and that these terms cannot be changed, modified or varied except by written instrument signed by both parties. In the event you issue a purchase order or memorandum or other instrument covering the services herein provided, it is hereby specifically agreed and understood that such purchase order, memorandum, or instrument is for your internal purposes only, and any and all terms and conditions contained therein, whether printed or written, shall be of no force or effect unless agreed to in writing by Concentric. No waiver by either parties of a breach hereof or default hereunder shall be deemed a waiver by such party of a subsequent breach or default of like or similar nature.

13. *Governing Law* – This Agreement (consisting of the Letter or Proposal and these terms) shall be construed and otherwise governed pursuant to the laws of the Commonwealth of Massachusetts. The attached Proposal, of which these General terms and Conditions (terms) form a part, constitutes an agreement of the parties hereto, and supersedes any previous agreement or understanding. It may not be modified except in writing, and only if executed by both parties.

AGREED AND ACCEPTED:

CLIENT SIGNATURE Roger Dall'Antonia

TITLE: Executive Vice President
Customer Service + Regulatory Affairs

COMPANY: Fortis BC Energy Inc.

DATE: January 6, 2015