Diane Roy
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Febuary 2, 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. 3698850

FortisBC Energy Inc. (FEI)

Application for Approval of Biomethane Energy Recovery Charge (BERC) Rate Methodology (the Application)

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

On August 28, 2015, FEI filed the Application referenced above. FEI respectfully submits the attached response to BCUC IR No. 2, in advance of the Streamlined Review Process scheduled for February 3, 2016.

As part of this fling, FEI provides a draft version of Tariff Supplement No. K-1, Biomethane Long-Term Large Volume Interruptible Long Term Sales Agreement, Rate Schedule 11B (the Tariff Supplement). It should be noted that the Tariff Supplement was drafted based on present negotiations with one particular customer and is still in draft form as the negotiations with the customer are still on-going. FEI provides the draft form for informational and illustrative purposes only, intending to indicate some key provisions such a Tariff Supplement will likely cover. However, it is important to point out that for each Tariff Supplement, the precise terms and conditions will inevitably vary depending on FEI's negotiations and agreement with a customer.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

THIS DOCUMENT IS PROVIDED FOR INFORMATIONAL AND IILUSTRATIVE PURPOSES ONLY

TARIFF SUPPLEMENT NO. K-1

BIOMETHANE LONG-TERM LARGE VOLUME INTERRUPTIBLE LONG TERM SALES AGREEMENT RATE SCHEDULE 11B

BETWEEN

AND

FORTISBC ENERGY INC.

Effective XXX

This Agreement is made effective as of _____, 2016.

BETWEEN:

FORTISBC ENERGY INC., a company incorporated under the laws of British Columbia having an office at 16705 Fraser Highway, Surrey, BC V4N 0E8

(hereinafter called "**FortisBC Energy**")

OF THE FIRST PART

AND:

(hereinafter called "**Customer**")

OF THE SECOND PART

BIOMETHANE LARGE VOLUME INTERRUPTIBLE LONG TERM SALES AGREEMENT

WHEREAS:

A. FortisBC Energy has a voluntary Biomethane Service program approved by the British Columbia Utilities Commission, which includes a Long Term Biomethane Service;

B. The Biomethane Service is subject to terms and conditions set forth in section 28 of FortisBC Energy General Terms and Conditions;

C. Under Rate Schedule 11B of FortisBC Energy, FortisBC Energy provides the large volume interruptible Biomethane Service;

D. The Customer wishes to participate in the Biomethane Service and desires to purchase from FortisBC Energy interruptible Biomethane in accordance with Rate Schedule 11B and the terms and conditions set out in this Agreement; and

E. The Customer and FortisBC Energy have also entered into a Transportation Agreement pursuant to Rate Schedule XX of FortisBC Energy (XX).

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the terms, conditions and limitations contained herein, the parties agree as follows:

1. TERMS AND CONDITIONS

1.1 Definitions

1.1.1 Except where the context otherwise requires, all words and phrases defined below, or in Rate Schedule 11B, or in the General Terms and Conditions of FortisBC Energy and used in this Agreement have the meanings set out below or in Rate Schedule 11B, or in the General Terms and Conditions of FortisBC Energy. Where any definitions set out below conflict with the definitions in Rate Schedule 11B or the General Terms and Conditions of FortisBC Energy, the definitions set out below govern.

(a) "Agreement" means this Biomethane Large Volume Interruptible Long Term Sales Agreement.

(b) "Biomethane Energy Recovery Charge" means the Biomethane Energy Recovery Charge per Gigajoule approved by the British Columbia Utilities Commission applicable to the Biomethane Service rather than the Long Term Biomethane Service.

(c) "Commencement Date" means the date the Customer starts to receive the Biomethane Service pursuant to this Agreement, specified in section 1.4.1 of this Agreement.

(d) "Commodity Cost Recovery Charge" means the Commodity Cost Recovery Charge per Gigajoule approved by the British Columbia Utilities Commission applicable to the Customer effective on the Commencement Date.

(e) "Contract Term" means the term specified in section 1.3.1 of this Agreement.

(f) "Expiry Date" means the XXth anniversary of the Commencement Date.

(g) "Long Term Biomethane Service" means the Biomethane Service under Rate Schedule 11B with a minimum Contract Term of 5 years or more and a specified Minimum Annual Quantity for each Year of the Contract Term.

(h) "Long Term Biomethane Service Charge" means the Biomethane Energy Recovery Charge less the discount rate per Gigajoule approved by the British Columbia Utilities Commission that is applicable to Customers entering into a contract with FortisBC Energy for the Long Term Biomethane Service in effect on the Commencement Date.

(i) "Maximum Annual Quantity" means the maximum quantity of Biomethane, measured in Gigajoules, that the Customer may purchase from FortisBC Energy per Year and agrees to pay in accordance with section 1.6.2 of this Agreement.

(j) "Minimum Annual Quantity" means the minimum quantity of Biomethane, measured in Gigajoules, that the Customer agrees to purchase and pay per Year, whether or not such quantity is actually consumed by the Customer.

(k) "Month" means, subject to any changes from time to time required by FortisBC Energy, the period beginning at 7:00 a.m. Pacific Standard Time on the first day of the calendar month and ending at 7:00 a.m. Pacific Standard Time on the first day of the next succeeding calendar month.

(l) "Termination Payment" means the amount payable by the Customer to FortisBC Energy on termination of this Agreement in accordance with sections 1.4.4 of this Agreement, calculated by:
   a.
   b.

1.2 Conditions of Sales

1.2.1 Conditions. While this Agreement is in effect, FortisBC Energy waives the condition of sale contained in Section 3.1 (a) of Rate Schedule 11B.

1.3 Security

1.3.1 In order to secure the prompt and orderly payment of the charges, including the Termination Payment, to be paid by the Customer to FortisBC Energy under this Agreement, FortisBC Energy may require the Customer to provide, and at all times maintain, security equal to:

(a)

(b)

1.4 Term, Expiry and Termination of the Agreement

1.4.1 Commencement Date. The Commencement Date for this Agreement is _____.

1.4.2 Contract Term. The term of this Agreement will begin on the Commencement Date of this Agreement and will expire at 7:00 am Pacific Standard Time on the Expiry Date.

1.4.3 Early Termination by FortisBC. This Agreement is subject to early termination by FortisBC Energy in accordance with section 12 of Rate Schedule 11B (Default or Bankruptcy).

1.4.4 Automatic Termination. This Agreement will be terminated automatically if the Customer no longer receives service under a Transportation Agreement.

1.4.5 Termination Payment. In the event that the Agreement is terminated prior to the Expiry Date through operation of sections 1.4.3 and 1.4.4 of this Agreement, in addition to any other amounts due and owing by the Customer to FortisBC Energy and despite any other remedies available at law or in equity, the Customer agrees to pay to FortisBC Energy the Termination Payment and to waive any right it may have to raise as a defense that the Termination Payment is excessive or punitive.

1.4.6 Other Remedies. FortisBC Energy and the Customer agree that, upon any termination of this Agreement under circumstances where FortisBC Energy is entitled to the Termination Payment and such payment, in addition to any other outstanding charges, is paid in full, FortisBC Energy shall be precluded from any other remedy against the Customer at law or in equity or otherwise (including an order for specific performance) and shall not seek to obtain any recovery, judgment, or damages of any kind, including consequential, indirect, or punitive damages, against the Customer or against any of its directors, officers, employees, partners, managers, members, shareholders in respect of the early termination of this Agreement.

1.5 Terms of Sale

1.5.1 Minimum Annual Quantity. The Customer agrees to purchase the Minimum Annual Quantity of XX GJ of Biomethane.

1.5.2 Additional Quantity of Biomethane. The Customer may, upon a written notice to FortisBC Energy no later than thirty (30) days in advance, purchase an additional quantity of Biomethane, with a Yearly total quantity of Biomethane purchased by the Customer not exceeding Maximum Annual Quantity set forth in section 1.5.3 of this Agreement.

1.5.3 Maximum Annual Quantity. The Maximum Annual Quantity of Biomethane that the Customer can purchase is XX Gigajoules, subject to availability of Biomethane as determined by FortisBC Energy in its sole discretion.

1.5.4 Curtailment. If FortisBC Energy determines that curtailment under section 4.2 of Rate Schedule 11B (Curtailment) is required, FortisBC Energy will reduce the Minimum Annual Quantity Yearly by an amount equal to the actual quantity of Biomethane curtailed by FortisBC Energy in the Year.

1.6 Rates and Charges

1.6.1 In respect of any quantity of Biomethane below and at the Maximum Annual Quantity sold to the Customer under this Agreement, the Customer will pay to FortisBC Energy:

a)
b)

1.6.2 In respect of any quantity of Biomethane above the Maximum Annual Quantity sold to the Customer per Year, the Customer agrees

1.6.3 Annual Adjustment. -

1.7 Year End Payment Adjustment

1.7.1 FortisBC Energy will, on or about 45 days after each anniversary of the Commencement Date, deliver to the Customer a statement for the preceding Year showing the payment amount due from the Customer in respect of any difference between the quantity of Biomethane purchased by the Customer and the Minimum Annual Quantity or the Maximum Annual Quantity.

1.8 Condition Precedent

1.8.1 All obligations of the parties to this Agreement are subject to the acceptance for filing by the British Columbia Utilities Commission of the rates, terms and conditions set out herein.

2. Rate Schedule 11B

2.1 Point of Delivery

All Biomethane sales under this Agreement will occur at the Point of Sale.

2.2 Title Transfer

Title transfer to the Customer will occur at the Point of Sale.

2.3 Additional Terms

2.3.1 All rates, terms and conditions set out in Rate Schedule 11B and the General Terms and Conditions of FortisBC Energy, as any of them may be amended by FortisBC Energy and approved from time to time by the British Columbia Utilities

Commission, are in addition to the terms and conditions contained in this Agreement and form part of this Agreement and bind FortisBC Energy and the Customer as if set out in this Agreement.

2.3.2 Unless otherwise specified, all references in Rate Schedule 11B to "a Sales Agreement", "the Sales Agreement", "a Rate Schedule 11B Sales Agreement", or "the Rate Schedule 11B Sales Agreement" shall be read as references to "the Agreement".

2.4 Payment of Amounts

Without limiting the generality of the foregoing, the Customer will pay to FortisBC Energy all of the amounts set out in Rate Schedule 11B for the services provided under that Rate Schedule and this Agreement.

2.5 Conflict

Where anything in Rate Schedule 11B or the General Terms and Conditions of FortisBC Energy conflicts with any of the terms and conditions set out in this Agreement, including Section 3.1(a) (Conditions), Section 3.2 (Security), Section 5.1 (Charges), Section 8.1 (Term), Section 8.2 (Automatic Renewal), Section 8.3 (Early Termination) of Rate Schedule 11B, this Agreement governs.

2.6 **Acknowledgment**

The Customer acknowledges receiving and reading a copy of Rates Schedule 11B and the General Terms and Conditions of FortisBC Energy and agrees to comply with and be bound by applicable terms and conditions set out therein. Without limiting the generality of the foregoing, the Customer is able to accommodate interruption or curtailment of Biomethane sales and releases FortisBC Energy from any liability for the Customer's inability to accommodate an interruption or curtailment of the Biomethane Service.

IN WITNESS WHEREOF the parties hereto have executed this Supplemental Agreement.

FORTISBC ENERGY INC.	**THE UNIVERSITY OF BRITISH COLUMBIA**
BY: _____	BY: _____
(Signature)	(Signature)
_____	_____
(Title)	(Title)
_____	_____
(Name – Please Print)	(Name – Please Print)
DATE: _____	DATE: _____

Schedule A

Table of Charges

Long Term Biomethane Service Charge (per Gigajoule)	$X.XX

Table of Contents **Page No.**

A. BIOMETHANE PROGRAM TO DATE

45.0 Reference: INTRODUCTION

Exhibit B-5, BCUC IR 1.5.1

Premium calculation update

In response to BCUC IR 1.5.1, FEI confirmed the following equation:

BERC rate = CCRA rate + Carbon Tax + BERC premium

45.1 As of January 1, 2016 rates, please confirm that the BERC premium is $11.205/GJ.[1] If not confirmed, please specify.

Response:

Confirmed.

45.2 Based on the indicative rate calculated as of January 1, 2016, as filed in the Fourth Quarter Report on the Biomethane Variance Account (BVA) and Biomethane Energy Recovery Charge (BERC) dated November 13, 2015 (2015 Fourth Quarter BVA Report), please confirm that the BERC premium is $12.863/GJ.[2] If not confirmed, please specify.

Response:

Confirmed.

45.2.1 Please file a copy of the 2015 Fourth Quarter BVA Report on a non-confidential basis.

Response:

Please refer to Attachment 45.2.1.

[1] BERC Premium = $14.414/GJ - $1.719/GJ - $1.4898/GJ = $11.205/GJ.
[2] BERC Premium = $16.072/GJ - $1.719/GJ - $1.4898/GJ = $12.863/GJ.

B. ALTERNATIVES CONSIDERED

46.0 Reference: ALTERNATIVES CONSIDERED
Exhibit B-5, BCUC IR 1.19.1, 1.19.2
RNG pricing alternatives

In the attachment to BCUC IR 1.19.1, FEI provides potential benefits and concerns regarding the status quo, FEI's proposal, and seven alternatives. In response to BCUC IR 1.19.2, FEI states that it is "essentially proposing a change to the price of the RNG [renewable natural gas] commodity, without otherwise affecting the design of the program. FEI believes that this will help increase customer participation in the program without changing the program design and incurring additional costs."

46.1 With respect to the FEI Proposal, please explain why there are no system implementation costs when compared with the status quo.

Response:

The proposed BERC rate methodology does not require further testing, development, or reconfiguration to current billing practices when compared with the status quo. The proposed BERC rate would simply replace the existing BERC rate in the billing system.

46.1.1 Would it be correct to say that FEI will resume marketing spending of $300,000 regardless if FEI remains under the status quo, or if FEI's proposals are approved?

Response:

No. Under the status quo FEI would not necessarily resume marketing spend to $300,000. If FEI's proposals are not approved, FEI will consider the Commission's decision, including any particular directions and determinations regarding the biomethane program, and reassess what level of spending would be appropriate going forward. Thus, for scenario analysis purposes, FEI maintained the current level of spending in the Status Quo alternative. Please also refer to the response to BCUC IRs 1.33.1.2 and 1.34.3.

46.2 If the Commission is to consider Option 1, please clarify if the low volume short term contract would be less than 2000 GJ per year or less than 499 GJ per year. Similarly, please clarify for the high volume short term contract. Please provide rationale for the threshold.

Response:

As a general comment, Options 1 to 7 were presented to FEI in BCUC IR 1.19.1 and do not represent options that FEI is recommending to the Commission. While FEI did not create these options and is unsure of the exact mechanics behind each option, FEI has responded to information requests based on its best understanding of how the options might work.

FEI notes that in Attachment 19.1 under the column entitled BERC Rate Mechanism for Option 1, the threshold was mistakenly stated to be 500 FJ instead of 2000 GJ as this option was described in the question posed by the Commission in BCUC IR 1.19.1. The BERC Rate Mechanism for Option 1 should have read as:

- *BERC Rate = CCRA Rate + Carbon Tax + $8.50 premium for short term contracts less than 2000 GJ per year.$1 discount from BERC Rate for short term contracts at a volume of greater than 2000 GJ.*
- *$2 discount from BERC Rate for long term contracts (at time of contract start)*

While FEI did not propose this option and is not recommending it, FEI considers 2000 GJ to be a possible threshold as it is the existing dividing line between Rate Schedule 2B and Rate Schedule 3B. If the Commission were to consider this option, aligning the threshold with existing Rate Schedules is preferable as it would allow FEI to remain consistent with its practice of keeping rates constant within rate schedules and it would minimize any changes to both tariffs and the billing system.

In addition to the concerns FEI's expressed with this view in Exhibit B-5, Attachment 19.1, this option does not offer a sufficiently low premium to lower volume customers. Based on experience to date as shown in the Application, customer surveys and the premiums of other utility green programs, a premium of $8.50 will likely continue to discourage participation from residential and small commercial customers. Furthermore, to reach the discounted premium, customers would have to consume over 2000 GJs, representing a bill impact of $15,000 at the discounted price. This would require a significant commitment from even large commercial customers.

More fundamentally, FEI does not believe that providing a discount based on volume without a long-term commitment is appropriate or necessary at this time. While providing an incentive for higher volume customers may increase the volume purchased from a particular customer, FEI would have no assurance that the higher volume purchases would continue. Without a long-

term commitment, there is less benefit to the biomethane program in terms of guaranteed revenues, reduced need for customer education and retention spending or matching demand with supply. As such, it is more difficult to justify the discounted rate. Further, FEI has not identified as a particular challenge the need to increase the volume commitment from existing or potential customers. FEI is therefore cautious about increasing the complexity of the program for this purpose. FEI would prefer to minimize change to address the primary challenge of a BERC rate that is too high and focus available dollars towards increasing awareness and uptake of the existing program.

46.3 With respect to Option 1, please illustrate an example to show "A R3B customer taking less than a 100% blend would be using less than 2,000 GJ of RNG so would be in the higher Short Term Contract price bracket, while a R3B customer taking 100% would be in the lower price Short Term Contract bracket." Show your calculations.

Response:

Please refer to the following table, which shows how customers in the same rate schedule may be charged a different rate due to differences in volume:

Rate Schedule	Annual Consumption (GJ/Year)	RNG Blend (%)	RNG Annual Consumption	Option 1 Short Term Contract Volume (GJ)	Option 1 Short Term Contract Premium (per GJ)
RS3B	3,000	50%	1,500[3]	< 2,000	$8.50
RS3B	2,100	100%	2,100[4]	> 2,000	$7.50

This example demonstrates why a combination of the option to take different blends and having a rate based on annual consumption complicates which BERC rate would be applicable, which would in turn complicate or require new biomethane rate schedules.

46.4 With respect to Option 1, please provide a breakdown of estimates that make up the $100,000 estimated system implementation cost.

[3] RNG Annual Consumption = 3,000GJ*0.50 RNG Blend = 1,500 GJ.
[4] RNG Annual Consumption = 2,100GJ*1.00 RNG Blend = 2,100 GJ.

Response:

The original high level estimate of $100,000 was based on the cost to replace the current biomethane program model, with what is proposed as Option 1. The following table shows an approximate breakdown of the estimate by function:

Option 1 System Function	Estimate ($000)
New contract structure: • Including the retirement of the current percentage blend model and migration to the new mechanism	$50
Periodic assessment of Step Qualification: • Complex calculation based on historical consumption • Automated reassessment and reclassification	$30
Mobility restriction: • This assumes that a firm contract exists for each customer based on a volume commitment over a defined time period	$20
Total	**$100**

As the above is a high level estimate developing during the IR process based on limited information about the potential option, if the Commission were to approve such an option, the actual implementation costs should be expected to vary from the estimate of $100,000.

46.5 With respect to Option 2, please illustrate an example to show "R3B customers on a higher blend buying more RNG than a R11B on a lower blend but paying a higher rate per GJ for the RNG." Show your calculations.

Response:

Under Option 2, two customers purchasing the same total amount of RNG may be paying different rates for that same amount. The following table illustrates this potential scenario.

Customer Rate Schedule	Total Annual Consumption (GJ)	RNG Annual Consumption (GJ)	RNG Blend (%)	Option 2 BERC Rate Premium (per GJ)	RNG Cost	Comment
RS3B	8,000	4,000	50%	$5	$20,000	Pays higher rate for the same amount of RNG
RS11B	20,000	4,000	25% *	$4	$16,000	

**RS 11B customers buy a fixed amount of RNG on a per GJ basis and do not enroll for specific blends in the same way as the other Rate Schedules. Therefore this is a back calculated percentage which takes the total amount of RNG purchased divided by the total consumption.*

46.6 With respect to Option 3, please explain why the estimated system implementation cost is half of Option 1.

Response:

FEI understands Option 1 to be a fundamental redesign and reconfiguration of the current system to stepped contractual rates. FEI understands Option 3 as being aligned with existing rate schedules and therefore can take advantage of existing calculations within the customer information system (CIS). As such, Option 3 is expected to be less costly to implement than Option 1.

46.7 With respect to Option 3, why does FEI rank this option least favourable? Would FEI agree that Option 3 is an extension of the FEI Proposal and does not face the challenges of Option 1 and 2? (i.e. complexity of different rate class and volumes.) Please explain.

Response:

FEI has ranked Option 3 as least favorable because of the potential challenges of fairness amongst and between Rate Schedules, complexity in communication and complexity of administration.

FEI does not see Option 3 to be an extension of the FEI proposal. The key difference is that FEI's proposal seeks to maintain existing Rate Schedules and maintain the principle that a single BERC rate is the default option for all voluntary customers. That is, in FEI's proposal, the discount is only provided to those customers that sign a long-term agreement.

46.8 With respect to Options 1-3 and 6, please provide a breakdown of estimates that make up the $120,000 incremental marketing costs. Describe the scope of additional work.

Response:

Options 1-3 and 6 as described in BCUC IR 1.19.1 offer multiple rates and are therefore considered more complex for customers to comprehend. Generally, FEI estimates that it would take a greater investment to educate customers on new changes to the Program, rather than just a change to the BERC rate, which is the only change that customers will see with FEI's proposal.

The high level estimate of an incremental marketing cost of $120,000 is based on FEI's experience when the program first launched. At that time, FEI incurred additional cost for customer awareness and education as customers had not been exposed to a program like this in the past. FEI anticipates a need for a similar additional investment if these options were implemented. For example, FEI anticipates additional costs to revise marketing materials (such as brochures, bill inserts, other paid media and website material) for the biomethane program.

46.9 With respect to Option 5, please clarify FEI's concerns about the potential confusion with respect to the carbon tax credits. Include examples if appropriate.

Response:

The reporting of emissions reductions and the claiming of the carbon tax credit is calculated on a per GJ basis. However, under a block-based approach, a block would not likely represent a particular number of GJs of biomethane.

Under the current Program and any option that uses a per GJ charge, customers can easily identify their carbon reduction on a per GJ basis when purchasing RNG. For customers reporting emissions, such as Public Service Organizations, this is critical since RNG has an established emission factor on a per gigajoule basis.

Likewise, the carbon tax credit (known as the biomethane credit) is easy to calculate and identify on the bill because there is a gigajoule for gigajoule substitution. For example, if a customer is purchasing 10 GJ of RNG and 90 GJ of regular natural gas, the carbon tax credit is equal to 10 GJ multiplied by the carbon tax.

If FEI were to adopt a block-based approach, these calculations would be less easily followed, because a block would not likely represent a particular number of gigajoules.

46.10 Does FEI believe that the potential benefits of the alternative options will outweigh the estimated system implementation and additional incremental marketing cost? If this analysis differs depending on the Options considered, please provide a response for each Option.

Response:

In considering the cost/benefit of each option FEI will address only the options which were identified as feasible in its response to BCUC IR 1.19.1.2.

FEI does not believe that the benefits of the alternative options presented by the Commission will outweigh the extra costs of implementation (including system changes and education and awareness spending) or the reduction in recoveries from customers. FEI believes its option is the best choice and comes with very few costs. As such, its cost/benefit ratio would be superior to that of the options presented by the Commission. In addition, FEI believes its option offers a better chance to recover more costs from customers than some of the options presented by the Commission.

The benefits identified in Options 1, 2, 3 and 6 generally support the potential for higher volume sales because they offer the potential for even lower prices than FEI has proposed. In addition to the added customer education and awareness costs required to implement these options (above that of the FEI option), cost recovery from voluntary customers may be lower than FEI's option. Further, as described in the response to BCUC IR 2.46.7, FEI also sees challenges in terms of fairness amongst and between rate schedules, complexity in communication and administration with respect to the options.

C. PROPOSED MARKET BASED BERC

47.0 Reference: Proposed Market Based BERC

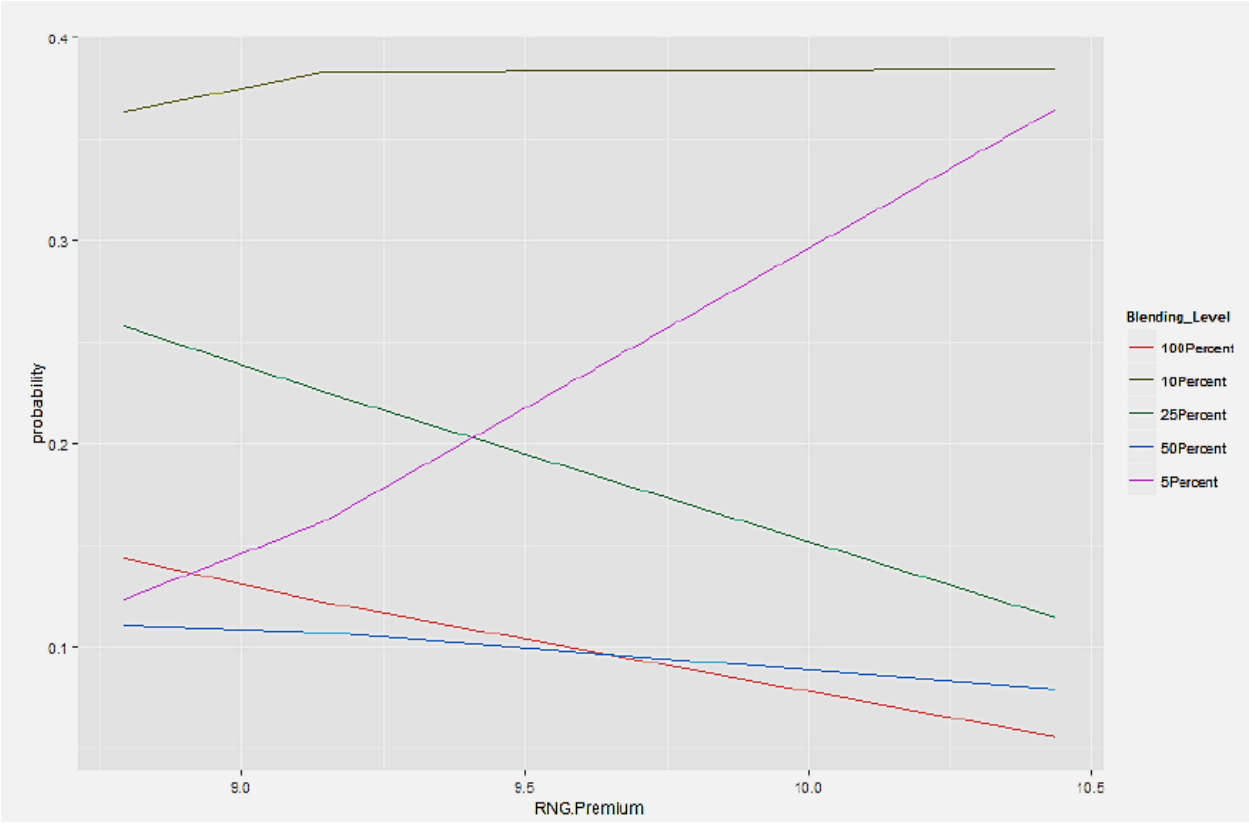
Exhibit B-5, BCUC IR 1.23.1

Elasticity of demand

In response to BCUC IR 1.23.1, FEI states:

> Using 2014 and 2015 data and multinomial regression, FEI has been able to estimate a demand curve for RNG for residential customers, and has also been able to determine an estimate of the elasticity of demand based on the relative probability of selecting a certain blend level at varying levels of RNG price premiums. Only residential data were analyzed as it was the only class that had adequate data points to meet the minimum degree of freedom to allow a statistical assessment of demand elasticity.

FEI shows the RNG demand curve for residential customers, with the relative probabilities of various RNG blends relative to various RNG Premiums.



Commission staff re-arranged the following table provided in FEI's response to BCUC IR 1.23.1:

Blending level	Average Elasticity
5 Percent	10.48
10 Percent	0.31
25 Percent	(2.98)
50 Percent	(1.50)
100 Percent	(3.27)

FEI states that the "10 percent blending option is least elastic to changes in the RNG price premium relative to other options. The 5 percent is the option most elastic to changes relative to other options, indicating that in the case of a price increase beyond the $10.50 per GJ RNG premium, customers are most likely to choose the 5 percent option over other options." [Emphasis added]

47.1 Please briefly explain the objectives and purpose of a multinomial regression, and why the multinomial regression is appropriate for the RNG demand curve and elasticity of demand. Why is a simple linear regression not appropriate in this case (e.g. using dummy variables)?

Response:

Multinomial logistic regression is used to model nominal outcome variables, in which the log odds of the outcomes are modeled as a linear combination of the predictor variables. The outcome of this exercise has five discrete choices for blending levels at 5%, 10%, 25%, 50% and 100%. As such, an appropriate model is one that analyzes the odds of various blending choices relative to the RNG Premium.

A simple linear regression takes an outcome variable that is continuous and therefore is not suitable to model categories of various blending levels.

47.2 Please provide the model equation(s) for this multinomial regression.

Response:

The model equations are as follows:

$$\ln\left(\frac{P(BlendingLevel = 10\%)}{P(BlendingLevel = 5\%)}\right) = b10 + b11 * RNG_{Premium}$$

$$\ln\left(\frac{P(BlendingLevel = 25\%)}{P(BlendingLevel = 5\%)}\right) = b20 + b21 * RNG_{Premium}$$

$$\ln\left(\frac{P(BlendingLevel = 50\%)}{P(BlendingLevel = 5\%)}\right) = b30 + b31 * RNG_{Premium}$$

$$\ln\left(\frac{P(BlendingLevel = 100\%)}{P(BlendingLevel = 5\%)}\right) = b40 + b41 * RNG_{Premium}$$

where the coefficients $bi0\ (Intercept), bi1(Premium)$ are estimated from the model. Subscript i corresponds to each level of RNG blending option.

47.3 Please provide the dataset for the multinomial regression. Show and explain that the residential rate class had adequate data. Show that other rate classes have inadequate data.

Response:

Attachment 47.3 contains the dataset used for the multinomial regression. The total count of 767 residential enrollment data was included since October 2014. Prior data were excluded as no multiple blending options were available at that time. This amount of data was considered to be adequate as significance tests with regards to the estimation of standard errors could be performed.

The commercial enrollments during the same time period are 12, 0 and 0 for RS2B, RS3B and RS11B, respectively. Given the total of 8 parameters to estimate, the degree of freedom associated with the commercial data sets makes it difficult to perform the significance tests with regards to the estimation of standard errors.

47.4 Please provide the regression summary (e.g. regression statistics, ANOVA table, coefficients, intercepts, etc.).

Response:

The multinomial regression summary is provided below showing the coefficient estimates, standard errors as well as the residual deviance and information criteria (AIC).

```
Coefficients:
     (Intercept)    Premium
0.1_     6.585120 -0.6259663
0.25_   10.901896 -1.1558662
0.5_     7.458213 -0.8606059
1_      11.004278 -1.2342385
Std. Errors:
     (Intercept)   Premium
0.1_     1.273424 0.1310530
0.25_    1.570726 0.1657000
0.5_     1.848723 0.1944822
1_       1.957800 0.2090673
Residual Deviance: 2215.527
AIC: 2231.527
```

With regard to the significance of each explanatory variable, a two tailed z test was performed showing the output below. All p values are significant at the 0.05 significance level.

```
(Intercept)      Premium
0.1_  2.326036e-07 1.784296e-06
0.25_ 3.902434e-12 3.044454e-12
0.5_  5.477684e-05 9.639120e-06
1_    1.901450e-08 3.557697e-09
```

47.5 Please provide the raw data and calculations to support the average elasticity figures.

Response:

The elasticity was measured as the percentage change in the relative probability of selecting a certain RNG blend level corresponding to a percentage change in the RNG premium. As the RNG demand curve has non-linear patterns, this change is not constant across various RNG premium values. As such, an average value was calculated for each of the blending levels. The average value is calculated by taking the average slope by connecting the two end points comprised of the minimum and maximum RNG premium values at roughly $8.79 and $10.44. The corresponding change in the relative probabilities at these end points, relative to the change in the RNG premiums at these end points, is the average elasticity. The calculation of the average elasticity as a ratio of the changes in the premium and relative probabilities for each blending level is as follows:

Premium	Blending Level	Relative probability	% Change in Premium	% Change in Relative Probability	Ratio of the changes
$ 8.79	0.05	0.12			
$ 10.44	0.05	0.37	0.19	1.96	10.48
$ 8.79	0.1	0.36			
$ 10.44	0.1	0.38	0.19	0.06	0.31
$ 8.79	0.25	0.26			
$ 10.44	0.25	0.11	0.19	(0.56)	(2.98)
$ 8.79	0.5	0.11			
$ 10.44	0.5	0.08	0.19	(0.28)	(1.50)
$ 8.79	1	0.14			
$ 10.44	1	0.06	0.19	(0.61)	(3.27)

47.6 How should a negative average elasticity be interpreted, if any different compared to a positive average elasticity?

Response:

A negative elasticity can be interpreted as a negative percentage change in the relative probability of selecting a certain RNG blending option responding to a percent increase in the RNG premium. A positive elasticity can be interpreted as a positive percentage change in the relative probability of selecting a certain RNG blending option corresponding to a percent increase in the RNG premium.

Thus, as the RNG premium increases, the negative elasticity estimates associated with higher blending options over 25 percent indicate that customers are less likely to choose higher blend options over lower blend options.

47.7 The proposed RNG premium is $7 for short term contracts and $6 for long term contracts. Why did FEI appear to choose an interval between $8.50 and $10.50 RNG Premium as shown in the graph in the preamble?

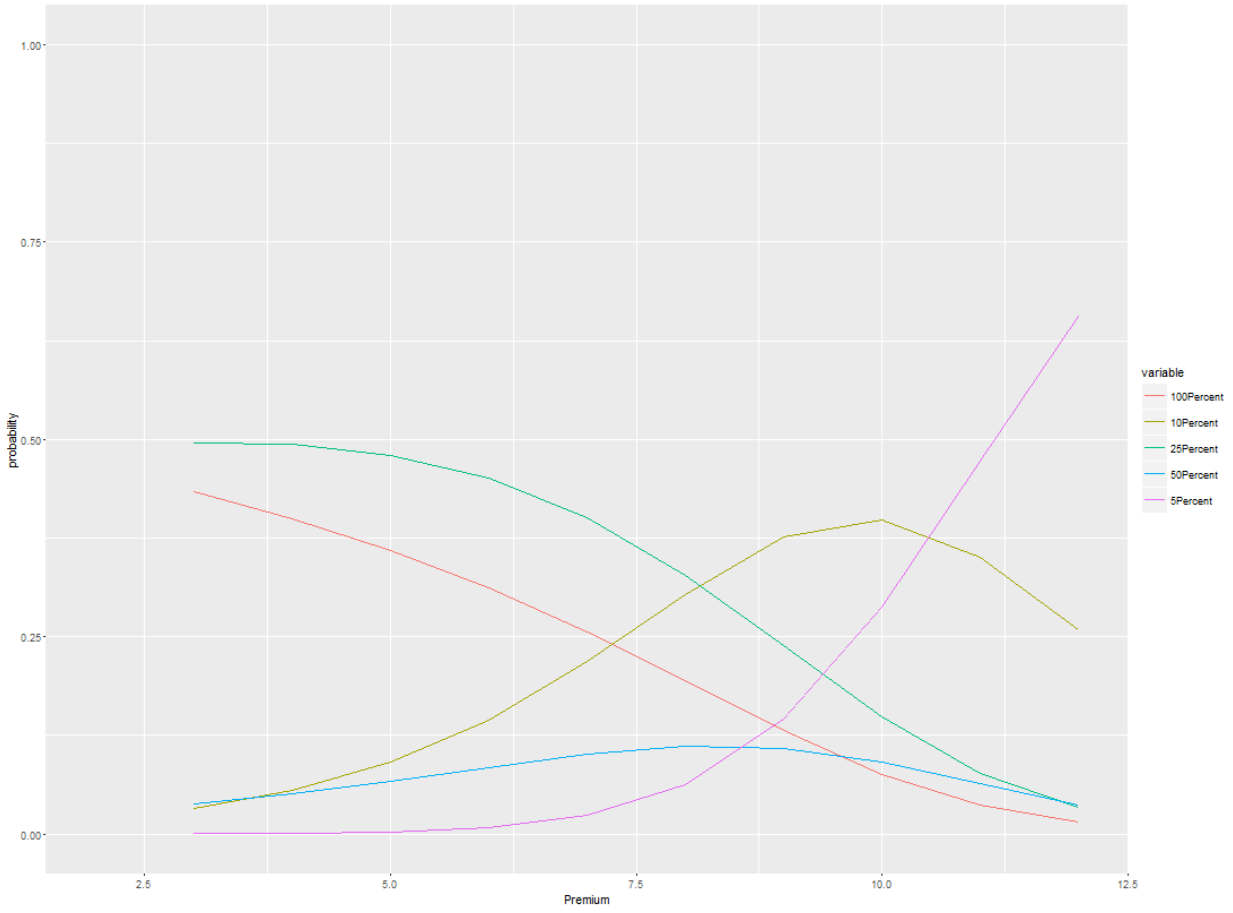
Response:

As set out in the response to BCUC IR 1.23.1, FEI analyzed the historical premium, blend and customer addition data that was available and did not use forecast data or the proposed premium level. The analysis was based on the residential dataset from the October 2014 to July 2015 period and the premium pricing available during the time period ranges from $8.79 to $10.44. Thus, FEI chose the interval between $8.50 and $10.50 as reflective of the historical pricing during the same time period.

47.8 Please expand the graph with the "RNG Premium" axis with a minimum value of $3 to a maximum value of $12, and expand the "probability" axis from 0 to 1. If not possible, please explain why.

Response:

The graph is expanded to show a minimum premium value of $3 to a maximum value of $12. The probability axis is expanded to show values from 0 to 1. Note that the demand curves shown here are estimated based on a set of discrete premium values ranging from $3 to $12 by one dollar increments and any probability value in between the set of the defined premium values is interpolated by connecting the nearest points. Any marginal differences in the curvature of this graph compared to the previous one may be a result of the difference in the predefined set of premium values.



47.9 How does FEI interpret the multinomial regression results? Please provide interpretations for each blend level (i.e. 5 percent, 10 percent, 25 percent, 50 percent and 100 percent), for each $1 increments from $3 to $12, with specific probability levels.

Response:

As shown in the demand curves provided in the response to BCUC IR 2.47.8, the probability level varies depending on the blending option as well as the premium level. The table below provides the likelihood of a certain blend option corresponding to various premium levels.

Interpretations are as follows:

At a $3 premium, the most likely option is 25% blending showing 49.5% probability of being selected over other options. The 100% blending option also has a high probability of being selected (43.4%). The lower blend options are unlikely given their low probabilities.

Similarly, at a $4 premium, the 25% blending option is still most likely given the probability of 49.3%. The 100% blending is the next likely option while the lower blending options show small probabilities.

This trend continues until the premium reaches $9, at which point the most likely option would be the 10 percent blending option. From $11 onwards, the most likely option is the 5 percent blending.

Although not linear, the overall trend indicates more likelihood towards lower blending options as the premium increases.

	Blend Level				
Premium	**100Percent**	**10Percent**	**25Percent**	**50Percent**	**5Percent**
$ 3	43.4%	3.2%	49.5%	3.8%	0.0%
$ 4	40.0%	5.5%	49.3%	5.1%	0.1%
$ 5	35.9%	9.1%	48.0%	6.7%	0.3%
$ 6	31.2%	14.4%	45.1%	8.5%	0.9%
$ 7	25.6%	21.8%	40.0%	10.1%	2.4%
$ 8	19.4%	30.4%	32.8%	11.1%	6.3%
$ 9	13.1%	37.6%	23.9%	10.9%	14.5%
$ 10	7.5%	39.8%	14.9%	9.1%	28.7%
$ 11	3.6%	35.0%	7.7%	6.3%	47.3%
$ 12	1.5%	25.9%	3.4%	3.7%	65.5%

47.9.1 In the 5 percent blend case, FEI states that "a price increase beyond the $10.50 per GJ RNG premium, customers are most likely to choose the 5 percent option over other options." [Emphasis added]

Please specify the probability associated with "most likely". Is it a 35 percent chance as indicated in the graph shown in the preamble? If not, please clarify.

Response:

Please refer to the response to BCUC IR 2.47.9.

47.9.1.1 Does the multinomial model have the ability to indicate which "other option" a customer will move towards (e.g. higher/lower blend) if a certain RNG premium is reached? How does the model account for the 0 percent blend option?

Response:

Please refer to the response to BCUC IR 2.47.9 with regard to the likelihood of a certain blend option.

The model does not account for the 0 percent blend option. In line with the multinomial framework to model the relative odds of nominal data, the model describes the relative probability of selecting a certain blending option relating to a premium but does not predict the absolute probability of choosing or not choosing (as in "the 0 percent option") the RNG program in general.

47.9.2 Based on FEI's interpretation, in the 5 percent blend case, is it true to say that a price decrease below the $9/GJ RNG premium, customers would have around 10 percent probability chance to stay in the 5 percent option? If not, please clarify.

Response:

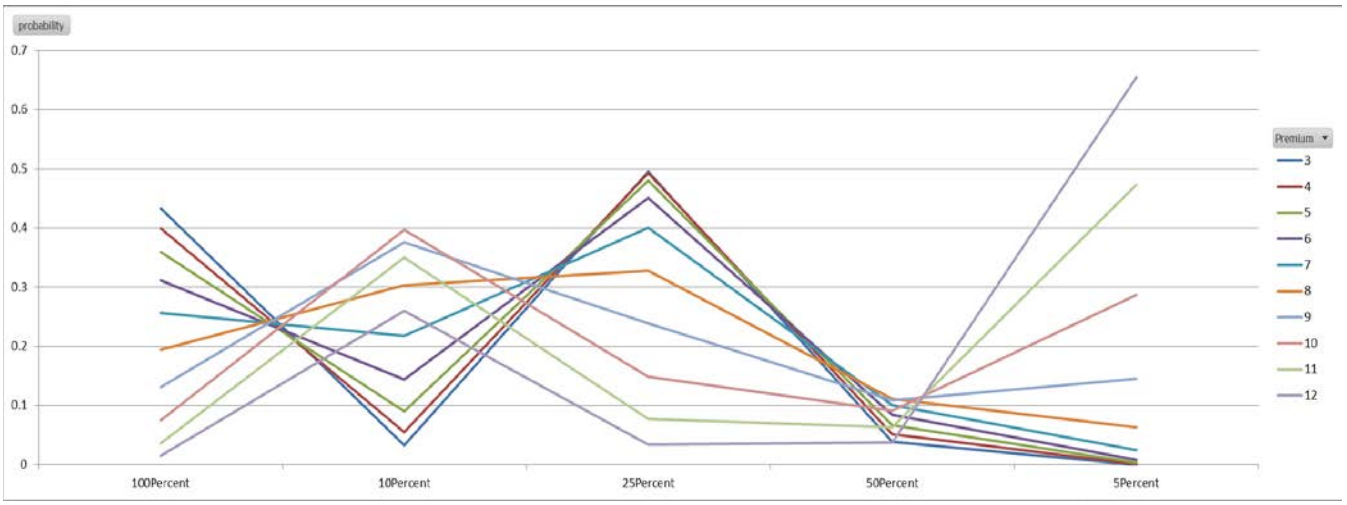
Not confirmed. Please refer to the response to BCUC IR 2.47.9.

47.10 A traditional demand curve shows price on the y-axis and quantity on the x-axis. Please provide a demand curve with RNG Premium (price) on the y-axis and blend level (quantity) on the x-axis. If not possible, please explain why.

Response:

The quantity in this case is the probability and not the blend level. The blend level is a categorical variable where various quantities (probabilities) correspond to. As there are a total of three variables to show, the previous chart showed the blending level as separate lines while y-axis showed the probability (quantity) and x-axis showed the RNG premium.

While it is not possible to show blend level as the quantity, FEI prepared the following chart showing the blend level on the x-axis to best accommodate the request. Various lines with different colours represent the RNG premium.



47.10.1 If possible, please calculate the elasticity of demand and provide interpretation. How do these results compare with the average elasticity calculated in the multinomial regression? Show your calculations.

Response:

Please refer to the response to BCUC IR 2.47.5 with regard to the calculation of the average elasticity. The average elasticity was chosen instead of a point estimate for the elasticity of demand as the change in the relative probability is not constant relative to an incremental change in the RNG premium. The elasticity value varies depending on a range of RNG premium values.

D. POTENTIAL IMPACT ON NON-RNG CUSTOMERS

48.0 Reference: SUPPLEMENTARY INFORMATION

Exhibit B-3, Supplementary Information, Attachment C, Tab Forecast Impacts;

Exhibit B-1-1, Evidentiary Update, Appendix E, Schedule 3;

Exhibit B-1-2, Errata, Figure 8-3;

Exhibit B-5, BCUC 1.37.1;

Exhibit B-5, BCUC 1.40.2.1

Forecast impacts on non-RNG customers at market-based BERC rate

Schedule 3 in Appendix E of Exhibit B-1-1 shown below provides the calculation of forecast impact of the proposed BERC rates on the non-RNG customers.

FORTISBC ENERGY INC.
2015 BERC Rate Methodology Application
Forecast Impacts at Market-Based BERC Rate

Schedule 3

Line No.	Particulars	2016	2017	2018	2019	2020
1						
2	Aged Inventory Transfer to Storage and Transport Rates					
3	GJs > 18 months in age	$ -	$ -	$ 346,070	$ 1,013,201	$ 1,450,737
4	Forecasted Natural Gas Commodity rate	$ 2.83	$ 2.97	$ 3.10	$ 3.27	$ 3.43
5	Aged inventory transfer - non-tax effected ($000)	-	-	(1,073)	(3,308)	(4,970)
6	Non-bypass Sales Volume	124,017.9	124,017.9	124,017.9	124,017.9	124,017.9
7	IMPACT TOTAL CUSTOMERS PER GJ	$ -	$ -	$ (0.0087)	$ (0.0267)	$ (0.0401)
8	IMPACT % of delivery margin	0.00%	0.00%	0.15%	0.46%	0.69%
9						
10						
11						
12						
13						
14	Transfer to Delivery Rates					
15	Tranfer all costs except Supply ending balance	(751)	114	(107)	(2,576)	(9,538)
16	Non-bypass Sales & Transportation Volume	175,315.3	175,315.3	175,315.3	175,315.3	175,315.3
17	IMPACT TOTAL CUSTOMERS PER GJ	$ (0.0043)	$ 0.0006	$ (0.0006)	$ (0.0147)	$ (0.0544)
18	IMPACT % of delivery margin	0.10%	-0.02%	0.01%	0.36%	1.32%
19						
20		$ 720,884	Delivery margin			
21						

In response to BCUC IR 1.40.2.1, FEI states:

> … a balance transferred to the UBPDA account from the BVA would be the result of any transfer of RNG supply to the MCRA. The volume of inventory would be transferred to the MCRA at the prevailing CCRA rate and would be recovered through Storage and Transport charges.

48.1 Please confirm, or otherwise explain, that the transfer of the aged inventory volume from the BVA to the MCRA results in a transfer of the associated revenue from the MCRA to the BVA (i.e. revenue equal to volume transferred times the prevailing CCRA rate.) For example, as shown in Schedule 3, in 2020 a volume of 1,450,737 gigajoules is transferred from the BVA to the MCRA, and a corresponding dollar amount of $4.97 million is transferred from the MCRA to the BVA.

Response:

Not confirmed. In this example, the $4.97 million associated with the inventory is the dollar amount credited to the BVA for the RNG that is being transferred to the MCRA and the value of RNG in the MCRA that will be recovered through Storage and Transport charges. There is no transfer of revenue from the MCRA to the BVA.

48.2 Please confirm, or otherwise explain, that the "balance transferred to the UBPDA account from the BVA" that results from the transfer of aged inventory to the MCRA, is a transfer of the net cost of the transferred biomethane (i.e. the cost of the biomethane less the revenue transferred from the MCRA to the BVA.)

Response:

The balance transferred to the UBPDA would be the remaining dollar value of the aged inventory in the BVA after the transfer to the MCRA. For example, if the aged inventory was valued at $10 million, and using the prevailing CCRA rate for the transfer to the MCRA resulted in a transfer from the BVA to the MCRA of $4.97 million, $5.03 million would be transferred to the UBPDA.

Please refer to the response to BCUC IR 1.48.1. Revenue is not transferred from the MCRA to the BVA.

48.2.1 Please confirm that this amount is included in line 15 on the Schedule 3 in the preamble above.

Response:

Please refer to the response to BCUC IR 1.48.2.

The transfer on line 15 of Schedule 3 is the transfer of all costs remaining in the BVA, which would include the residual value of the aged inventory transferred to the MCRA, amongst other costs.

48.2.2 Please confirm that this "balance transferred to the UBPDA account from the BVA" that results from the transfer of RNG supply to the MCRA does not include the amount on line 5 of Schedule 3 (i.e. the $4.97 million in 2020.)

Response:

Confirmed.

48.3 Please confirm, or otherwise explain, that line 8 on Schedule 3, that is titled "IMPACT % of delivery margin", is the cost of the aged inventory transfer (i.e deemed cost of the biomethane transferred to the MCRA) divided by the 2016 delivery margin total of $720,884.

Response:

Confirmed.

48.3.1 Please confirm, or otherwise explain, that the percentages shown on line 8 of Schedule 3, do not represent the impact of the transfer of aged inventory to the MCRA on the delivery margin, and are therefore not meaningful numbers.

Response:

The percentages shown on line 8 do represent the transfer of aged inventory to the MCRA as compared to the delivery margin. As an example in 2020, the transfer of $4.97 million to the MCRA represents 0.69% of FEIs delivery margin (based on 2015 non-bypass revenue excluding rate 46).

Although the transfer will not be recovered through delivery rates, for purposes of providing a comparison for customers and to give a sense of the magnitude as compared to the impact of the other transfer, FEI believes that this is useful information.

BCUC IR 1.37.1 referenced the following information extracted from Schedule 3, in tab Forecast Impacts in the "fully functional spreadsheet" in Attachment C to the Supplementary Information that is Exhibit B 3 (which is the same as shown in Schedule 3 in Appendix E of Exhibit B-1-1), summarizing in percentage terms the impact of FEI's proposed market-based BERC rates on FEI's non-RNG customers:

	2015	2016	2017	2018	2019	2020
Aged Inventory Transfer to Storage and Transport Rates IMPACT % of delivery margin	0.00%	0.00%	0.00%	0.15%	0.46%	0.69%
Transfer to Delivery Rates IMPACT % of delivery margin	0.00%	0.10%	-0.02%	0.01%	0.36%	1.32%
Total Impact Non-bypass Sales Volume	0.00%	0.10%	-0.02%	0.16%	0.82%	2.01%

When asked in BCUC IR 1.37.1 whether FEI considers a 2.01 percent impact to be significant, FEI elaborated by stating:

> Based on the current annual bill of a residential customer of approximately $80624, a 1.32% increase to delivery rates represents approximately $6 per year or approximately $0.50 per month, and a 0.69% increase to storage and transport rates represents approximately $0.83 per year.25

In footnote 24 to BCUC IR 1.37.1, FEI notes that this assumes a lower mainland customer consuming 90 GJ per year and in footnote 25, FEI sets out how the $6 and $0.83 per year impact respectively, are calculated from the current annual bill amount of $806.

48.4 Please confirm, or otherwise explain, that Schedule 3 shows, for a typical residential customer with an annual consumption of 90 GJ per year, the impact of

transfers to delivery rates in 2020 would be $4.90 (i.e. $0.0544 times 90 GJ) and the impact of the aged inventory transfer to the MCRA in 2020 would be $3.60 (i.e. $0.0401 times 90 GJ).

Response:

Confirmed.

48.5 Does FEI agree that the 2.0% total impact referenced in BCUC 1.37.1 is not an accurate reflection of the impact on the delivery margin for FEI's non-bypass customers? If not, please explain why not.

Response:

No, FEI does not agree. FEI believes that the 2% total impact as compared to delivery margin is a reasonable reflection of the expected impact on Residential customers.

In FEI's table reproduced in the preamble to BCUC IR 1.37.1, and as restated in the response, FEI estimates the delivery rate impact to be 1.32% in 2020 or approximately $6 per year. The estimated annual bill impact provided in that response was based on rates and annual bill calculations as at the time of the response.

As noted in the response to BCUC IR 2.48.3.1, FEI determined the percent impact to Storage and Transport Rates of 0.69% based on the delivery margin. FEI should have updated the calculation for purposes of the response to BCUC IR 1.37.1 to be based on total Storage and Transport Costs and not Delivery Margin, which would result in a rate impact of approximately 2.4% rather than 0.69%, equating to approximately $2.88 per year rather than $0.83 per year, for a total annual bill impact of approximately $8.98 rather than the $6.83 noted in the response to BCUC IR 1.37.1.

If the total annual bill impact of $8.98 is compared to the delivery portion of a Residential customer's annual bill of approximately $462, the percent impact is 1.92%. As such, FEI believes that the 2.0% total impact as compared to delivery margin provides a useful point of comparison for customers.

48.6 Does FEI agree that $4.90 and $3.60, respectively, are more accurate estimates of the impacts to a residential customer in 2020 than $6 and $0.83 as calculated by FEI in response to BCUC 1.37.1? If not, please explain why not.

Response:

Please refer to the response to BCUC IR 2.48.5. FEI has restated the annual bill impact associated with expected changes in Storage and Transport rates.

The estimated impact to delivery rates of $0.0544 per GJ and storage and transport of $0.0401 per GJ in 2020[5] reflect the total transfer amount divided by total GJs. This calculation provides an average per GJ rate for all non-bypass rate schedules in 2020. While a reasonable calculation, it is not reflective of how delivery rates are changed for each rate schedule, which reflects the underlying cost allocation. Applying the percentage rate change to the annual bill, as done in the response to BCUC IR 1.37.1, is a more accurate representation of the expected rate and annual bill impact for a Residential customer.

However, FEI notes that the total annual bill impact of $8.50 calculated by using the average GJ approach equates to approximately 1.8% of the delivery portion of Residential customers annual bill and is thus consistent with 2.0% impact stated as a percentage of delivery rates.

[5] Schedule 3 lines 7 and 17.

49.0 Reference: SUPPLEMENTARY INFORMATION

Exhibit B-1-1, Appendix E, Schedule 3;

Exhibit B-5, BCUC 1.40.2.1

Forecast impacts on non-RNG customers at market-based BERC rate

In response to BCUC IR 1.40.2.1, FEI states:

> … a balance transferred to the UBPDA account from the BVA would be the result of any transfer of RNG supply to the MCRA. The volume of inventory would be transferred to the MCRA at the prevailing CCRA rate and would be recovered through Storage and Transport charges.

49.1 Please confirm, or otherwise explain, that the transfer of aged inventory from the BVA to the MCRA at the prevailing CCRA rate, effectively has the same dollar impact on the MCRA balance, expressed in dollars as if this same quantity of conventional natural gas was physically purchased from the market at the prevailing CCRA rate.

Response:

Confirmed.

49.2 Does FEI agree that at the time this aged inventory biomethane was originally delivered onto the FEI system it would have displaced conventional gas purchases? (i.e. FEI would have required a lesser volume of conventional gas supply on that day to balance the system and meet the daily load requirement of its non-RNG customers.) If not, please explain.

Response:

Confirmed.

50.0 Reference: EVIDENTIARY UPDATE

Exhibit B-5, BCUC 1.34.0;

FEI Rate Schedule 14A

Applicable Rate Schedules

In response to BCUC IR 1.34.1, when asked to describe the RNG customer categories used internally by FEI in its demand model, FEI states:

> The remaining two categories are used internally by FEI to categorize customers served under Rate Schedule 11B which may include biomethane customers served under an existing transportation agreement with a gas marketer or customers purchasing RNG direct from FEI under Rate Schedule 14A.

50.1 Please confirm that FEI sells RNG to the transportation service customers who have selected FEI as their Shipper Agent under Rate Schedule 11B, and not and Rate Schedule 14A.

Response:

All RNG sales to transportation service customers will be pursuant to Rate Schedule 11B regardless of whether they have appointed a Shipper Agent or have elected FEI to act as their Shipper Agent under Rate Schedule 14A.

50.1.1 If not confirmed, please provide the reference in Rate Schedule 14A that provides for the sale of RNG to these customers under this Rate Schedule.

Response:

Please refer to the response to BCUC IR 2.50.1.

51.0 Reference: EVIDENTIARY UPDATE

Exhibit B-1-1, Appendix E;

Exhibit B-1-2, Errata, Figure 8-3

Longer term impact on non-RNG customers

In the evidentiary update in Exhibit B-1-1, Appendix E provides the financial analysis. Figure 8-3 in Exhibit B-1-2 shows the summary of market-based rate + yearly clearing impacts to 1, the BVA, MCRA and Non- RNG Customers.

51.1 Please provide an updated version of each of the schedules shown in Appendix E of the Evidentiary Update that is Exhibit B-1-1, with the time period extended by an additional five years out to 2025. Please state all assumptions.

Response:

Please refer to Attachment 51.1. For purposes of extending the analysis, FEI held all financial variables such as tax, return and debt rates constant as outlined in the response to BCUC IR 1.31.1 in Exhibit B-5. Further, the extended demand and supply forecasts are provided in Schedules 2 and 4, respectively, in Attachment 51.1.

51.1.1 Please provide fully functional copies of the associated spreadsheet models.

Response:

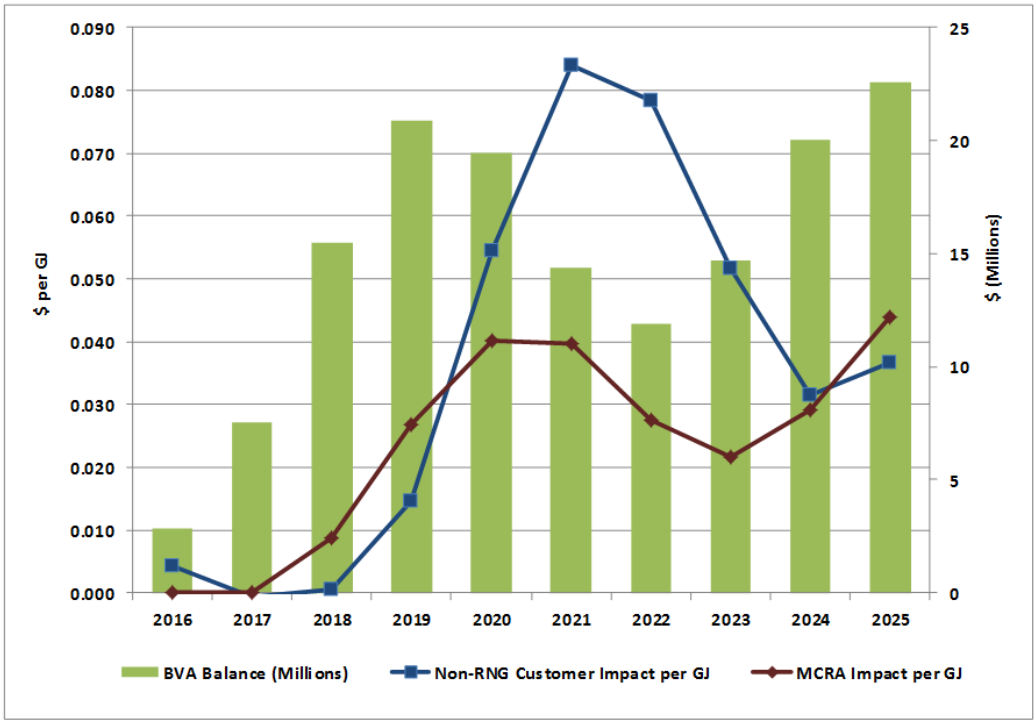
The fully functional excel spreadsheet is included as Attachment 51.1.1.

51.2 On Figure 8-3 as shown in Exhibit B-1-2, please explain whether the “Non-RNG Customer Impact per GJ” as shown in Figure 8-3 continues to increase year over year beyond 2020, or whether it can be expected to level off and/or decrease at some point.

Response:

Please refer to the expanded Figure 8-3 shown below. Under the proposal, the non-RNG Customer Impact per GJ is expected to track downwards following 2021.

Figure 8-3: Summary of Market-Based Rate + Yearly Clearing Impacts to the BVA, MCRA and Non-RNG Customers[1]



Notes:

[1] Estimated impacts as at December 31.

51.2.1 Please describe the conditions under which it would level off and/or decrease.

Response:

The conditions under which the Non-RNG customer impact would level off or decrease would include an overall drawdown of supply due to voluntary demand, an ongoing balance between supply and demand quantities and an increase in natural gas commodity charges such that the value of any inventory transfers would be closer to the BERC rate.

51.2.2 If supply additions continue to be limited by the price and volume caps set out in the 2013 Biomethane Decision, provide the maximum "Non-RNG Customer Impact per GJ", and provide a projection of the year that the maximum impact is anticipated to occur.

Response:

FEI interprets this question such that the price for any supply projects commencing in 2017 are priced at the cap of $15.28 per GJ. This assumption was applied to the version of the analysis included in the response to BCUC IR 2.51.1. No changes to assumptions regarding the supply cap and demand are required.

Based on the assumptions noted above, the maximum Non-RNG customer impact per GJ would be $0.0859 per GJ in 2021 or a $7.73 impact to the annual bill for a typical residential customer with an annual consumption of 90 GJs per year. The Non-RNG impact then decreases to $0.0361 per GJ or a $3.249 impact to the annual bill in 2025.

51.2.3 If no further supply is added beyond the supply contracts with the City of Surrey and the City of Vancouver, describe how this would be anticipated to change the trend and magnitude of the "Non-RNG Customer Impact per GJ."

Response:

FEI interprets this question such that FEI's proposal is in place; however, no additional supply beyond City of Surrey and City of Vancouver is added to the Biomethane supply portfolio.

Keeping in place all other assumptions embedded in the analysis provided in response to BCUC IR 2.51.1, if no further projects are added beyond the City of Surrey and the City of Vancouver, the trend with respect to the impact on Non-RNG customers would continue to increase to $0.0731 GJ in 2021 compared to $0.0544 in 2020, and then steadily decrease annually to $0.0132 in 2025.

The following table provides a comparison of this scenario with the analysis provided in response to BCUC IR 2.51.1.

Non RNG Impact - No Projects Added Beyond City of Surrey and Vancouver

Particulars	Proposed Projects	BCUC IR 2.51.2.3	Increase / (Decrease)
Supply Volume (GJ) - in 2025	1,392,942	794,010	(598,932)
Direct Capital (cumulative) ($,000)	7,000	(7,000)	(7,000)
O&M (cumulative) ($,000)	818	(818)	(818)
BVA balance ($,000)	22,609	16,497	(6,112)
Transfer all costs except ending supply ($, 000)	62,308	44,075	(18,233)
Transfer all costs except ending supply -2021 (per GJ)	0.0839	0.0731	(0.0108)
Transfer all costs except ending supply -2025 (per GJ)	0.0366	0.0132	(0.0234)

The development of biomethane supply will be in accordance with supply parameters as set out by the Commission, which FEI expects to remain at 1.5 PJ and $15.28 per GJ. To the extent that these supply parameters change and the supply cap is reduced, FEI expects that it will be even more challenging to sign up long term larger volume customers and as such, the reduction in supply may not result in a lower BVA balance or per GJ as shown in the table above.

51.3 On Figure 8-3 as shown in Exhibit B-1-2, please explain whether the cost per gigajoule of the "MCRA Impact per GJ" as shown in Figure 8-3 continues to increase year over year beyond 2020, or whether it can be expected to level off and/or decrease at some point.

Response:

Please refer to the response to BCUC IR 2.51.2.

51.3.1 Please describe the conditions under which it would level off and/or decrease.

Response:

The conditions under which the MCRA impact would level off or decrease would include an overall drawdown of supply due to voluntary demand and an ongoing balance between supply and demand quantities.

52.0 Reference: POTENTIAL IMPACT ON NON-RNG CUSTOMERS

Exhibit B-8, CEC IR 1.20.1

Impact on non-RNG customers

In response to CEC IR 1.20.1, when asked to explain the decline in the Non-RNG Customer Impact per GJ from 2017 to 2018 FEI states "the forecast recoveries from demand and valuation of the ending inventory result in a forecast net benefit transfer to delivery rates in 2017." FEI goes on to provide a table that shows a figure of $114,000 for the 2017 transfer of all cost except supply ending balance.

52.1 Please confirm, or otherwise explain, that the forecast amount for 2017 is a net benefit of $114,000.

Response:

Confirmed.

52.2 Please explain whether FEI intends to automatically transfer the resulting amount out of the BVA regardless whether it is a net cost or a net benefit.

Response:

Yes, FEI will transfer the resulting net cost or net benefit from the BVA to be recovered or provided to customers. To the extent that a net benefit transfer occurs, FEI believes that a symmetrical mechanism that provides this benefit to non-RNG customers is appropriate as it reduces the cumulative net cost over time to non-RNG customers. Further, a symmetrical mechanism is aligned with the principle of moderating the impacts to non-RNG customers as outlined in the Application and in the response to BCUC IR 1.1.1.

52.3 If FEI intends to transfer a net benefit amount out of the BVA, please explain how this is aligned with the objectives of the Application.

Response:

Please refer to the response to BCUC IR 2.52.2.

E. ACCOUNTING TREATMENT AND RATE SETTING

53.0 Reference: ACCOUNTING TREATMENT AND RATE SETTING
Exhibit B-5, BCUC IR 1.9.1, 1.9.1 Attachment;
FEU 2012-2013 RRA Decision, p. 73
Sponsorship costs

On page 73 of the FortisBC Energy Utilities (FEU) 2012-2013 Revenue Requirements Application (RRA) Decision, the Commission states:

> Accordingly, the Commission Panel directs that all Community Involvement Spending will be allocated 50 percent to the ratepayer and 50 percent to the shareholder.

In BCUC IR 1.9.1 FEI states that "FEI does not specifically break down marketing spend by rate class or type of cost" and noted that sponsorship accounted for 10 percent of past marketing activities for 2012 2015 Projected.

Commission staff have extended the table provided in response to BCUC IR 1.9.1 to reflect FEI's stated allocation, and the allocation directed in the FEU 2012-2013 RRA Decision.

RNG Program Marketing Cost Breakdown

Category	2011	2012	2013	2014	2015 Projected	Total
RNG Program Marketing - Total	$384,725	$300,978	$321,083	$166,815	$175,000	
Sponsorship 10 percent	$38,473	$30,098	$32,108	$16,682	$17,500	$96,388
50 percent of Sponsorship		$15,049	$16,054	$8,341	$8,750	$48,194

53.1 Does FEI agree that the above table accurately reflects the allocation of the sponsorship portion of the RNG program marketing costs? If not, please explain.

Response:

As noted in the response to BCUC IR 1.9.1, FEI does not specifically track marketing spend by type of cost; however, the table provided in the question preamble accurately calculates ten percent of the RNG program spend that FEI estimated was related to sponsorships.

Regarding the 50 percent allocation that is shown as the last line in the table, this calculation is not relevant to the sponsorships that were referred to in the 2012-2013 RRA Decision.

The meaning of the word sponsorship as used in response to BCUC IR 1.9.1 is not the same as or analogous to the type of sponsorship spending that was referred to as being a component of Community Involvement Spending in the 2012-2013 RRA Decision.

The 2012-2013 RRA Decision directed that 50 percent of Community Involvement Spending be allocated to the shareholder. The Community Involvement Spending that was the subject of the direction in the 2012-2013 RRA Decision was described as being made up of three components – the Employee Give Where You Live Program, Community Investment Projects, and Local Community Events and Other Program Sponsorships. The Local Community Events and Other Program Sponsorships that is subject to the 50 percent allocation was described as follows in the response to BCUC IR 1.61.1 in the 2012-2013 RRA proceeding:

> "These events and sponsorships include strategic business partnerships that engage customers, community opinion leaders and policy makers who have an impact on our business objectives. These sponsorships are a fundamental element of our strategic communication plan and ongoing public consultation."

A list of the types of items included in this category was included in the response to BCUC IR 2.26.1 in the 2012-2013 RRA proceeding, and none of the items listed in that response related to biomethane education for customers.

In the context of the Biomethane Program and the response to BCUC IR 1.9.1, "sponsorship" refers to the attendance at trade shows and public markets for the purpose of customer education and awareness. An example of this would be where FEI purchases booth space at a local biomethane forum to increase RNG program awareness. This spending directly relates to customer education and awareness of the Biomethane Program and is not the same as or analogous to the type of spending that was the subject of 50/50 sharing in the 2012/2013 RRA Decision. Therefore, this spending is not subject to 50/50 sharing between customers and the shareholder and FEI has not allocated any of this spending to the shareholder for the period 2012-2015.

53.2 Please confirm, or otherwise explain, that 50 percent of the past marketing activities for the period from 2012 through 2015 were allocated to the shareholder as directed by the Commission in the FEU 2012-2013 RRA Decision.

Response:

Please refer to the response to BCUC IR 2.53.1.

54.0 Reference: ACCOUNTING TREATMENT AND RATE SETTING

Exhibit B-5, BCUC IR 1.29.3

Emissions Regulations Deferral Account

In BCUC IR 1.29.3 FEI states:

> The Compliance with Emissions Regulations Deferral Account, approved by Commission Order G-44-12, captures potential compliance costs and revenues collected from the sale of carbon credits. On page 111 of the Decision (dated April 12, 2012) (Emissions Regulations Deferral Account, pages 109 to 111.)

54.1 For the Emissions Regulations Deferral Account, please provide the following:

a. The timeline for recovery;

b. The carrying costs; and

c. The term that the account is approved for, or when it will be subsequently reviewed.

Response:

The Emissions Regulations Deferral Account does not have an approved amortization period. At the time the account was set up it was not known with certainty the extent of costs or benefits that may be captured in this account and in this regard it was appropriate to reserve setting an amortization period until the nature and extent of the costs and benefits are known. Once material additions to the account occur, FEI will seek approval for an amortization period as part of an Annual Review or Revenue Requirements Application process.

As a rate base deferral account, carrying costs will be calculated using the approved return on rate base.

Finally, the account does not have a specified term of approval. As noted in the response to BCUC IR 1.29.3, FEI is required to provide to the Commission a detailed description of the accounting methodologies to track and record costs and/or revenues added to this account. Thus, once the account is used, FEI will provide the Commission with the details of each type of transaction that results in an addition to the account.

55.0 Reference: ACCOUNTING TREATMENT AND RATE SETTING

Exhibit B-5, BCUC IR 1.40.2

Unsold Biomethane Premium Deferral Account (UBPDA)

With respect to the UBPDA, FEI states the following In BCUC IR 1.40.2:

> If the Commission were to direct the use of a separate deferral account and rate rider mechanism, FEI would propose a rate base deferral account with an amortization period of one year. To the extent that the RNG Program remains in place, this would be an ongoing account and thus there would not be an expiration date for this account.

55.1 Please provide the carrying costs that would apply to the UBPDA.

Response:

As stated in the response to BCUC IR 1.40.2, FEI expects that this account would be in rate base. As such, the carrying costs associated with the account would be the interest expense and equity return based on the approved interest rates and return on equity as embedded in the approved return on rate base each year.

55.2 Does FEI agree the UBPDA should be periodically reviewed (i.e. every 3 to 5 years) to determine if it is still required and continues to serve its original objective? Please explain why, or why not.

Response:

While FEI is not opposed to a periodic review of the UBPDA account, FEI does not believe that such a review is necessary. To the extent that annual reporting of the BVA remains in place, the Commission will have information every year on the activity in the BVA, which would include transfers to the MCRA and the UBPDA. Further, to the extent that the UBPDA is embedded in the annual revenue requirements of FEI as a rate base deferral account, the account will be included in the financial schedules that are reviewed as part of Annual Review or Revenue Requirements Applications. Finally, as with all deferral accounts, in the event that there is a need to change the purpose of the account or if the account is no longer needed, FEI will seek the necessary Commission approvals.

Attachment 45.2.1

Diane Roy
Director, Regulatory Services

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November 13, 2015

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI or the Company)

2015 Fourth Quarter Report on the Biomethane Variance Account (BVA) and Biomethane Energy Recovery Charge (BERC) (the 2015 Fourth Quarter BVA Report)

Pursuant to British Columbia Utilities Commission (the Commission) Order G-210-13 and the accompanying Decision dated December 11, 2013, on the Biomethane Service Offering: Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis (the Decision), the attached materials provide the 2015 Fourth Quarter BVA Report. By Order G-177-14 dated November 14, 2014, the Commission approved an increase in the BERC rate to a rate of $14.414/gigajoule (GJ), effective January 1, 2015. As well, the Commission accepted on an interim basis, pending a review of FEI's BERC rate methodology proposal in 2015, the BERC rate change guidelines FEI proposed in its 2014 Fourth Quarter Report on the BVA and BERC (the Interim Guidelines).

Based on the biomethane gas supply cost assumptions (i.e. project in-service date, cost of service, and production volumes) and the forecast biomethane recoveries at the present BERC rate, the BVA balance before accounting for the value of the unsold biomethane quantities is projected to be approximately $1,208 thousand deficit after tax at December 31, 2015 (Tab 1, Page 2, Column 14, Line 8).

Further, the BVA balance at December 31, 2015 and December 31, 2016, based on the existing BERC rate and after adjustment for the value of the unsold biomethane quantities is forecast to be approximately $331 thousand deficit after tax (Tab 1, Page 2, Column 14, Line 11) and $490 thousand deficit after tax (Tab 1, Page 2, Column 14, Line 24), respectively.

The monthly deferral account activity and balances for the BVA are shown on the schedules provided at Tab 1, Pages 1 and 2 – the schedule at Page 1 displays energy quantities, and the schedule at Page 2 displays dollar amounts. The schedule at Tab 1, Page 3 provides a breakdown of the monthly actual and forecast biomethane recoveries by rate class. The schedules at Tab 1, Pages 4.1C to 4.3C provide a breakdown of the monthly actual and forecast biomethane supply costs by project.

At Tab 1, Page 5 the Company provides a re-calculation of the BERC rate, based on an January 1, 2016 effective date. Based on the BVA cost and recovery assumptions for the 12-month period ending December 31, 2016, and the projected December 31, 2015 unsold biomethane quantity, the tested rate increase is calculated to be $1.658/GJ (Tab 1, Page 5, Column 3, Line 25), indicating that change to the BERC rate is required at this time as per the Interim Guidelines[1].

Pursuant to Commission Order G-177-14, FEI filed a proposed rate methodology for the BERC on August 28, 2015. In the application FEI is seeking for approval of a BERC rate methodology based on the FEI natural gas Commodity Cost Recovery Charge with a pre-set premium. The application is currently going through the regulatory process. Therefore, FEI proposes no BERC rate change in this 2015 Fourth Quarter BVA Report. Pending the Commission decision on the BERC methodology application, FEI anticipates the BERC rate will be subject to resetting in early 2016. The estimated impact to the BVA of leaving the BERC rate unchanged at January 1, and based on the forecast sales of approximately 48.8 TJ for the period ending March 31, 2016, is approximately $81 thousand on a pre-tax basis.
The schedule at Tab 1, Page 6 provides the monthly biomethane inventory change since January 2014, as well as the age of biomethane inventory sold each month as determined on a first in, first out basis.

The Company requests the information contained in Tab 1 at Pages 4.1C, 4.2C, and 4.3C be treated as CONFIDENTIAL.

CONFIDENTIALITY

Consistent with past practice and previous discussions and positions on the confidentiality of selected filings (and further emphasized in the Company's January 31, 1994 submission to the Commission) FEI is requesting that this information be filed on a confidential basis pursuant to Section 71(5) of the *Utilities Commission Act* and requests that the Commission exercise its discretion under Section 6.0 of the Rules for Natural Gas Energy Supply Contracts and allow these documents to remain confidential. FEI believes this will ensure

[1] The guidelines and criteria for BERC rate changes comprised the following:
(i) Annual resetting of the BERC rate on an annual basis effective January 1st of a given year;
(ii) A threshold of $1.00 per GJ that will trigger a rate reset. That is, if a Quarterly Report indicates a change greater than $1.00 per GJ (plus or minus) is required, the BERC rate will be reset.

that market sensitive information is protected, and FEI's ability to obtain favourable commercial terms for future gas contracting is not impaired.

In this regard, FEI further believes that the Core Market could be disadvantaged and may well shoulder incremental costs if utility gas supply procurement strategies as well as contracts are treated in a different manner than those of other gas purchasers, and believes that since it continues to operate within a competitive environment, there is no necessity for public disclosure and risk prejudice or influence in the negotiations or renegotiation of subsequent contracts.

We trust the Commission will find the attached to be in order. However, should any further information be required, please contact Doug Richardson at 604-592-7643.

Sincerely,

FORTISBC ENERGY INC.

Original signed by:

Diane Roy

Attachments

FORTISBC ENERGY INC.
SUMMARY OF BIOMETHANE VARIANCE ACCOUNT (BVA) QUANTITIES
ACTUAL AND FORECAST ACTIVITY ENDING DECEMBER 31, 2017
(Quantities shown in TJ)

Line No.	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded (1)	Recorded (1)	Recorded	Recorded	Recorded	Forecast	Forecast	**Total**
2		Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	**2015**
3	Biomethane Available for Sale - Beginning	79.9	70.4	63.9	63.3	63.5	67.2	75.6	72.6	76.1	78.0	77.7	81.6	79.9
4	Purchases	7.8	8.3	13.3	12.8	12.9	12.0	11.2	12.4	11.6	10.8	19.6	19.6	152.4
5	Sales	(17.3)	(14.8)	(13.9)	(12.7)	(9.2)	(3.6)	(14.3)	(8.8)	(9.7)	(11.1)	(15.7)	(18.9)	(150.1)
6	Biomethane Available for Sale - Ending	70.4	63.9	63.3	63.5	67.2	75.6	72.6	76.1	78.0	77.7	81.6	82.2	82.2 (2)
7														
8														
9		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
10		Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	**2016**
11	Biomethane Available for Sale - Beginning	82.2	85.6	92.5	101.6	114.0	130.1	148.4	167.5	186.5	204.8	222.7	237.0	82.2
12	Purchases	21.3	22.7	24.3	25.0	26.3	27.0	27.3	27.3	27.0	29.8	29.5	29.8	317.2
13	Sales	(17.8)	(15.9)	(15.1)	(12.7)	(10.1)	(8.7)	(8.2)	(8.3)	(8.7)	(11.9)	(15.2)	(18.4)	(151.0)
14	Biomethane Available for Sale - Ending	85.6	92.5	101.6	114.0	130.1	148.4	167.5	186.5	204.8	222.7	237.0	248.3	248.3
15														
16														
17		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
18		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	**2017**
19	Biomethane Available for Sale - Beginning	248.3	261.7	276.2	292.2	310.5	331.7	354.0	377.1	400.1	422.4	441.8	457.6	248.3
20	Purchases	31.2	30.4	31.2	31.0	31.2	31.0	31.2	31.2	31.0	31.2	31.0	31.2	372.8
21	Sales	(17.9)	(15.9)	(15.2)	(12.6)	(10.1)	(8.7)	(8.1)	(8.3)	(8.6)	(11.8)	(15.2)	(18.4)	(150.8)
22	Biomethane Available for Sale - Ending	261.7	276.2	292.2	310.5	331.7	354.0	377.1	400.1	422.4	441.8	457.6	470.4	470.4

Notes: (1) June sales were understated by 5.5 TJ, the correction was booked in July.

(2) Lower ending balance than previous forecasts due to less supply. Kelowna plant was closed for maintenance; and Fraser Valley Biogas did not supply at maximum level.

Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
SUMMARY OF BVA BALANCES AT EXISTING BIOMETHANE ENERGY RECOVERY CHARGE (BERC)
ACTUAL AND FORECAST ACTIVITY ENDING DECEMBER 31, 2017
(Amounts shown in $000)

Line No.	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1		Restated [1]	Adjusted [2]	Adjusted [2]	Adjusted [2]	Adjusted [2]	Adjusted [2] [3]	Recorded	Recorded	Recorded	Recorded	Forecast	Forecast	**Total**
2		Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	**2015**
3	BVA Balance - Beginning (Pre-tax)	$ 1,390	$ 1,272	$ 1,193	$ 1,269	$ 1,299	$ 1,500	$ 1,729	$ 1,654	$ 1,763	$ 1,775	$ 1,794	$ 1,736	$ 1,390
4	Costs Incurred	$ 133	$ 132	$ 277	$ 212	$ 334	$ 281	$ 131	$ 236	$ 152	$ 178	$ 169	$ 169	$ 2,405
5	Revenue from **Existing BERC** Rate	$ (250)	$ (212)	$ (200)	$ (183)	$ (133)	$ (52)	$ (206)	$ (127)	$ (140)	$ (160)	$ (227)	$ (273)	$ (2,163)
6	BVA Balance - Ending (Pre-tax)	$ 1,272	$ 1,193	$ 1,269	$ 1,299	$ 1,500	$ 1,729	$ 1,654	$ 1,763	$ 1,775	$ 1,794	$ 1,736	$ 1,632	$ 1,632
7														
8	BVA Balance - Ending (After Tax)	$ 942	$ 883	$ 939	$ 961	$ 1,110	$ 1,280	$ 1,224	$ 1,305	$ 1,314	$ 1,328	$ 1,284	$ 1,208	$ 1,208
9														
10	Adjustment for Value of Unsold Biomethane at **Existing BERC** Rate (After Tax) [4]													$ (877)
11	**Adjusted BVA Balance - Ending (After Tax)**													$ 331
12														
13														
14		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
15		Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	**2016**
16	BVA Balance - Beginning (Pre-tax)	$ 1,632	$ 1,704	$ 1,823	$ 1,998	$ 2,193	$ 2,440	$ 2,714	$ 3,000	$ 3,284	$ 3,583	$ 3,849	$ 4,066	$ 1,632
17	Costs Incurred	$ 329	$ 347	$ 393	$ 377	$ 393	$ 400	$ 404	$ 404	$ 425	$ 437	$ 436	$ 441	$ 4,787
18	Revenue from **Existing BERC** Rate	$ (257)	$ (229)	$ (218)	$ (182)	$ (146)	$ (126)	$ (118)	$ (120)	$ (125)	$ (171)	$ (220)	$ (265)	$ (2,177)
19	BVA Balance - Ending (Pre-tax)	$ 1,704	$ 1,823	$ 1,998	$ 2,193	$ 2,440	$ 2,714	$ 3,000	$ 3,284	$ 3,583	$ 3,849	$ 4,066	$ 4,242	$ 4,242
20														
21	BVA Balance - Ending (After Tax)	$ 1,261	$ 1,349	$ 1,479	$ 1,623	$ 1,806	$ 2,008	$ 2,220	$ 2,430	$ 2,651	$ 2,849	$ 3,009	$ 3,139	$ 3,139
22														
23	Adjustment for Value of Unsold Biomethane at **Existing BERC** Rate (After Tax) [4]													$(2,649)
24	**Adjusted BVA Balance - Ending (After Tax)**													$ 490
25														
26														
27		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
28		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	**2017**
29	BVA Balance - Beginning (Pre-tax)	$ 4,242	$ 4,463	$ 4,700	$ 4,987	$ 5,280	$ 5,614	$ 5,964	$ 6,327	$ 6,687	$ 7,063	$ 7,373	$ 7,632	$ 4,242
30	Costs Incurred	$ 480	$ 466	$ 505	$ 475	$ 480	$ 475	$ 480	$ 480	$ 500	$ 480	$ 479	$ 484	$ 5,782
31	Revenue from **Existing BERC** Rate	$ (258)	$ (229)	$ (218)	$ (182)	$ (145)	$ (125)	$ (117)	$ (119)	$ (124)	$ (170)	$ (219)	$ (265)	$ (2,173)
32	BVA Balance - Ending (Pre-tax)	$ 4,463	$ 4,700	$ 4,987	$ 5,280	$ 5,614	$ 5,964	$ 6,327	$ 6,687	$ 7,063	$ 7,373	$ 7,632	$ 7,851	$ 7,851
33														
34	BVA Balance - Ending (After Tax)	$ 3,303	$ 3,478	$ 3,690	$ 3,907	$ 4,154	$ 4,414	$ 4,682	$ 4,949	$ 5,227	$ 5,456	$ 5,648	$ 5,810	$ 5,810
35														
36	Adjustment for Value of Unsold Biomethane at **Existing BERC** Rate (After Tax) [4]													$(5,018)
37	**Adjusted BVA Balance - Ending (After Tax)**													$ 792

Notes: (1) January 1, 2015 opening deferral balance was restated to reverse an adjustment error identified in the Response to the BCUC IR No. 1 on the 2015 Second Quarter Report on the BVA and BERC filed on June 5, 2015 (Attachment 2.1).

(2) The monthly costs for January - March were incorrectly recorded and an adjusting entry booked in April to correct the costs on a year to date basis. The adjusted monthly costs are used for the purpose of this quarterly report

(3) June sales were understated by 5.5 TJ, the correction was booked in July.

(4) Adjustment calculated based on quantity of Biomethane Available For Sale (Tab 1, Page 1) at the effective BERC Rate.

Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
COST RECOVERY BY RATE CLASS FOR BIOMETHANE
ACTUAL AND FORECAST ACTIVITY ENDING DECEMBER 31, 2017

Line	Particulars	Recorded Jan 15	Recorded Feb 15	Recorded Mar 15	Recorded Apr 15	Recorded May 15	Recorded Jun 15	Recorded Jul 15	Recorded Aug 15	Recorded Sep 15	Recorded Oct 15	Forecast Nov 15	Forecast Dec 15	**Total 2015**
1	**Sales (GJ)**													
2	Residential	8,346	6,089	5,265	4,442	2,122	1,582	1,393	1,389	2,240	3,450	7,983	10,618	54,919
3	Commercial	1,301	1,776	1,115	875	436	476	358	343	431	559	1,350	1,903	10,923
4	On/Off System & Other	7,646	6,932	7,501	7,361	6,677	1,519	12,562	7,106	7,046	7,067	6,408	6,408	84,233
5	**Total Sales**	17,293	14,797	13,881	12,678	9,235	3,577	14,313	8,838	9,717	11,076	15,741	18,929	150,075
6														
7	**Effective Rate** [(1)]	$ 14.481	$ 14.336	$ 14.415	$ 14.414	$ 14.411	$ 14.405	$ 14.414	$ 14.413	$ 14.414	$ 14.414	$ 14.414	$ 14.414	
8														
9	**Cost Recovered**													
10	Residential	$ 120,319	$ 87,773	$ 75,880	$ 64,022	$ 30,565	$ 22,794	$ 20,067	$ 20,014	$ 32,282	$ 49,724	$115,067	$153,048	$ 791,555
11	Commercial	18,761	25,587	16,100	12,606	6,290	6,857	5,157	4,935	6,219	8,056	19,459	27,430	157,459
12	On/Off System & Other	111,339	98,767	108,117	106,106	96,235	21,876	181,088	102,429	101,555	101,867	92,365	92,365	1,214,108
13	**Total Recovered**	$ 250,420	$ 212,128	$ 200,097	$ 182,734	$133,090	$ 51,526	$206,312	$127,378	$140,057	$159,647	$226,891	$272,843	$2,163,122
14														
15														
16														

Line		Forecast Jan 16	Forecast Feb 16	Forecast Mar 16	Forecast Apr 16	Forecast May 16	Forecast Jun 16	Forecast Jul 16	Forecast Aug 16	Forecast Sep 16	Forecast Oct 16	Forecast Nov 16	Forecast Dec 16	**Total 2016**
17														
18	**Sales (GJ)**													
19	Residential	10,272	8,584	7,923	5,784	3,593	2,407	1,946	2,073	2,375	5,132	8,133	10,840	69,062
20	Commercial	1,729	1,454	1,376	1,033	692	489	395	415	474	892	1,273	1,709	11,931
21	On/Off System & Other	5,838	5,838	5,838	5,838	5,838	5,838	5,838	5,838	5,838	5,838	5,838	5,838	70,056
22	**Total Sales**	17,839	15,876	15,137	12,655	10,123	8,734	8,179	8,326	8,687	11,862	15,244	18,387	151,049
23														
24	**Effective Rate**	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	
25														
26	**Cost Recovered**													
27	Residential	$ 148,061	$ 123,730	$ 114,202	$ 83,371	$ 51,790	$ 34,694	$ 28,050	$ 29,880	$ 34,233	$ 73,973	$117,229	$156,248	$ 995,460
28	Commercial	24,922	20,958	19,834	14,890	9,974	7,048	5,694	5,982	6,832	12,857	18,349	24,634	171,973
29	On/Off System & Other	84,149	84,149	84,149	84,149	84,149	84,149	84,149	84,149	84,149	84,149	84,149	84,149	1,009,787
30	**Total Recovered**	$ 257,131	$ 228,837	$ 218,185	$ 182,409	$145,913	$125,892	$117,892	$120,011	$125,214	$170,979	$219,727	$265,030	$2,177,220
31														
32														
33														

Line		Forecast Jan 17	Forecast Feb 17	Forecast Mar 17	Forecast Apr 17	Forecast May 17	Forecast Jun 17	Forecast Jul 17	Forecast Aug 17	Forecast Sep 17	Forecast Oct 17	Forecast Nov 17	Forecast Dec 17	**Total 2017**
34														
35	**Sales (GJ)**													
36	Residential	10,473	8,742	8,060	5,878	3,648	2,441	1,972	2,097	2,401	5,184	8,209	10,919	70,024
37	Commercial	1,684	1,412	1,337	1,005	664	468	381	404	461	873	1,251	1,690	11,630
38	On/Off System & Other	5,760	5,760	5,760	5,760	5,760	5,760	5,760	5,760	5,760	5,760	5,760	5,760	69,120
39	**Total Sales**	17,917	15,914	15,157	12,643	10,072	8,669	8,113	8,261	8,622	11,817	15,220	18,369	150,774
40														
41	**Effective Rate**	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	$ 14.414	
42														
43	**Cost Recovered**													
44	Residential	$ 150,958	$ 126,007	$ 116,177	$ 84,725	$ 52,582	$ 35,185	$ 28,424	$ 30,226	$ 34,608	$ 74,722	$118,325	$157,386	$1,009,326
45	Commercial	24,273	20,353	19,272	14,486	9,571	6,746	5,492	5,823	6,645	12,583	18,032	24,360	167,635
46	On/Off System & Other	83,025	83,025	83,025	83,025	83,025	83,025	83,025	83,025	83,025	83,025	83,025	83,025	996,296
47	**Total Recovered**	$ 258,256	$ 229,384	$ 218,473	$ 182,236	$145,178	$124,955	$116,941	$119,074	$124,278	$170,330	$219,381	$264,771	$2,173,256

Notes: (1) Effective recovery rate in January, February and June were different from tariff, due to errors in January and June, which was/will be corrected in February and July. Slight difference in March - May due to rounding.

FORTISBC ENERGY INC.
INCURRED COSTS FOR BIOMETHANE
ACTUAL AND FORECAST ACTIVITY ENDING DECEMBER 31, 2015

Line	Particulars	Adjusted [1] Jan 15	Adjusted [1] Feb 15	Adjusted [1] Mar 15	Adjusted [1] Apr 15	Adjusted [1] May 15	Adjusted [1] Jun 15	Recorded Jul 15	Recorded Aug 15	Recorded Sep 15	Recorded Oct 15	Forecast Nov 15	Forecast Dec 15	**Total 2015**
1	**All Supply Projects**													
2	Total Purchases (GJ)	7,812	8,309	13,269	12,835	12,932	12,049	11,224	12,373	11,627	10,795	19,574	19,574	152,373
3	Biogas / Biomethane Purchase Costs	$ 94,113	$ 95,868	$ 163,529	$ 161,505	$ 161,568	$ 130,152	$ 135,034	$ 150,925	$ 163,789	$ 146,239	$ 197,586	$ 198,273	$ 1,798,581
4														
5	**Salmon Arm Cost of Service**													
6	Cost of Service before O&M	$ 23,721	$ 15,784	$ 19,753	$ 19,753	$ 19,753	$ 19,753	$ 19,753	$ 19,753	$ 19,753	$ 19,753	$ 7,867	$ 7,867	$ 213,261
7	O&M Costs	3,615	3,700	73,564	931	43,520	21,088	3,980	34,091	40,726	26,549	2,930	2,930	257,624
8	**Total**	$ 27,336	$ 19,484	$ 93,317	$ 20,684	$ 63,272	$ 40,841	$ 23,732	$ 53,844	$ 60,479	$ 46,302	$ 10,797	$ 10,797	$ 470,885
9														
10	**Kelowna Cost of Service**													
11	Cost of Service before O&M [2]						$ -	$ (68,447)	$ (68,447)	$ (68,447)	$ (68,447)	$ (68,447)	$ (68,447)	$ (410,680)
12	O&M Costs [3]						43,843	5,000	22,153	28,511	31,820	15,571	15,571	162,470
13	**Total**						$ 43,843	$ (63,447)	$ (46,293)	$ (39,935)	$ (36,626)	$ (52,875)	$ (52,875)	$ (248,210)
14														
15	General Admin. Costs [4]	$ 11,444	$ 16,887	$ 19,798	$ 30,247	$ 109,357	$ 65,814	$ 36,019	$ 77,986	$ (32,304)	$ 22,506	$ 13,100	$ 13,100	$ 383,954
16														
17														
18														
19														
20	Total Cost	$ 132,893	$ 132,240	$ 276,644	$ 212,435	$ 334,197	$ 280,650	$ 131,339	$ 236,462	$ 152,029	$ 178,420	$ 168,608	$ 169,295	$ 2,405,211

Notes: (1) Monthly costs are adjusted to more appropriately reflect costs in each period.

(2) Consistent with the Cost of Service model, Cost of Service charges commence the month following the in-service date.

(3) No O&M costs forecast in July due to unplanned equipment failure.

(4) Approximately $163K (after tax, as of June 30, 2015) costs related to the City of Vancouver project development was excluded.

FORTISBC ENERGY INC.
INCURRED COSTS FOR BIOMETHANE
FORECAST ACTIVITY ENDING DECEMBER 31, 2016

Line	Particulars	Forecast Jan 16	Forecast Feb 16	Forecast Mar 16	Forecast Apr 16	Forecast May 16	Forecast Jun 16	Forecast Jul 16	Forecast Aug 16	Forecast Sep 16	Forecast Oct 16	Forecast Nov 16	Forecast Dec 16	**Total 2016**
1	**All Supply Projects**													
2	Total Purchases (GJ)	21,278	22,730	24,278	25,004	26,278	27,004	27,278	27,278	27,004	29,778	29,504	29,778	317,196
3	Biogas / Biomethane Purchase Costs	$210,670	$228,584	$249,670	$258,627	$274,164	$280,847	$285,164	$285,164	$280,847	$318,664	$317,707	$322,080	$3,312,191
4														
5	**Salmon Arm Cost of Service**													
6	Cost of Service before O&M	$ 23,577	$ 23,577	$ 23,577	$ 23,577	$ 23,577	$ 23,577	$ 23,577	$ 23,577	$ 23,577	$ 23,577	$ 23,577	$ 23,577	$ 282,926
7	O&M Costs	6,250	6,250	31,250	6,250	6,250	6,250	6,250	6,250	31,250	6,250	6,250	6,250	125,000
8	**Total**	$ 29,827	$ 29,827	$ 54,827	$ 29,827	$ 29,827	$ 29,827	$ 29,827	$ 29,827	$ 54,827	$ 29,827	$ 29,827	$ 29,827	$ 407,926
9														
10	**Kelowna Cost of Service**													
11	Cost of Service before O&M	$ 35,816	$ 35,816	$ 35,816	$ 35,816	$ 35,816	$ 35,816	$ 35,816	$ 35,816	$ 35,816	$ 35,816	$ 35,816	$ 35,816	$ 429,796
12	O&M Costs	25,500	25,500	25,500	25,500	25,500	25,500	25,500	25,500	25,500	25,500	25,500	25,500	306,000
13	**Total**	$ 61,316	$ 61,316	$ 61,316	$ 61,316	$ 61,316	$ 61,316	$ 61,316	$ 61,316	$ 61,316	$ 61,316	$ 61,316	$ 61,316	$ 735,796
14														
15	General Admin. Costs	$ 27,600	$ 27,600	$ 27,600	$ 27,600	$ 27,600	$ 27,600	$ 27,600	$ 27,600	$ 27,600	$ 27,600	$ 27,600	$ 27,600	$ 331,200
16														
17														
18														
19														
20	Total Cost	$329,414	$347,328	$393,414	$377,371	$392,908	$399,591	$403,908	$403,908	$424,591	$437,408	$436,451	$440,823	$4,787,112

FORTISBC ENERGY INC.
INCURRED COSTS FOR BIOMETHANE
FORECAST ACTIVITY ENDING DECEMBER 31, 2017

Line	Particulars	Forecast Jan 17	Forecast Feb 17	Forecast Mar 17	Forecast Apr 17	Forecast May 17	Forecast Jun 17	Forecast Jul 17	Forecast Aug 17	Forecast Sep 17	Forecast Oct 17	Forecast Nov 17	Forecast Dec 17	**Total 2017**
1	**All Supply Projects**													
2	Total Purchases (GJ) [(1)]	31,230	30,408	31,230	30,956	31,230	30,956	31,230	31,230	30,956	31,230	30,956	31,230	372,845
3	Biogas / Biomethane Purchase Costs	$335,368	$322,252	$335,368	$330,996	$335,368	$330,996	$335,368	$335,368	$330,996	$335,368	$334,891	$339,319	$4,001,661
4														
5	**Salmon Arm Cost of Service**													
6	Cost of Service before O&M	$ 27,705	$ 27,705	$ 27,705	$ 27,705	$ 27,705	$ 27,705	$ 27,705	$ 27,705	$ 27,705	$ 27,705	$ 27,705	$ 27,705	$ 332,454
7	O&M Costs	6,250	6,250	31,250	6,250	6,250	6,250	6,250	6,250	31,250	6,250	6,250	6,250	125,000
8	**Total**	$ 33,955	$ 33,955	$ 58,955	$ 33,955	$ 33,955	$ 33,955	$ 33,955	$ 33,955	$ 58,955	$ 33,955	$ 33,955	$ 33,955	$ 457,454
9														
10	**Kelowna Cost of Service**													
11	Cost of Service before O&M	$ 56,182	$ 56,182	$ 56,182	$ 56,182	$ 56,182	$ 56,182	$ 56,182	$ 56,182	$ 56,182	$ 56,182	$ 56,182	$ 56,182	$ 674,183
12	O&M Costs	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000	312,000
13	**Total**	$ 82,182	$ 82,182	$ 82,182	$ 82,182	$ 82,182	$ 82,182	$ 82,182	$ 82,182	$ 82,182	$ 82,182	$ 82,182	$ 82,182	$ 986,183
14														
15	General Admin. Costs	$ 28,100	$ 28,100	$ 28,100	$ 28,100	$ 28,100	$ 28,100	$ 28,100	$ 28,100	$ 28,100	$ 28,100	$ 28,100	$ 28,100	$ 337,200
16														
17														
18														
19														
20	Total Cost	$479,605	$466,488	$504,605	$475,233	$479,605	$475,233	$479,605	$479,605	$500,233	$479,605	$479,127	$483,555	$5,782,498

Notes: (1) Total purchases include approved projects only. Therefore, forecast purchases from City of Surrey and City of Vancouver included in the BERC Methodology Application are excluded in the report.

FORTISBC ENERGY INC.
BVA AND BERC REVIEW
FOR THE FORECAST 12-MONTH PERIOD ENDING DECEMBER 31, 2016
(Amounts shown pre-tax unless otherwise indicated)

Line No.	Particulars	$000	TJ	Notes
	(1)	(2)	(3)	(4)
1	**Forecast BVA Balance - Deficit at December 31, 2015**			
2	Cost (Tab 1, Page 2, Column 14, Row 6)	$ 1,632.1		
3	Quantity (Tab 1, Page 1, Column 14, Row 6)		82.2	Unsold Quantity
4				
5	**Forecast Costs Incurred in the 12-Month Period**			
6	Cost (Tab 1, Page 2, Column 14, Row 17)	$ 4,787.1		
7	Quantity (Tab 1, Page 1, Column 14, Row 12)		317.2	Purchase Quantity
8				
9	**Biomethane Available for Sale in the 12-Month Period**			
10	**Total Cost to be Recovered**	**$ 6,419.2**		
11	**Total Quantity**		**399.4**	
12				
13				
14				
15	**Calculation of Tested BERC Effective January 1, 2016**			
16				
17				
18	**Tested BERC** = Cost of Biomethane Available for Sale in the 12-Month Period	$ 6,419.2	= **$ 16.072**	per Gigajoule
19	Quantity of Biomethane Available for Sale in the 12-Month Period	399.4		
20				
21				
22	Existing BERC (effective January 1, 2015)		$ 14.414	per Gigajoule
23				
24				
25	**Tested Rate Increase (Decrease)**		**$ 1.658**	per Gigajoule

Date	Monthly Activity					Cumulative Quantities		
	Beginning Balance *(in TJ)*	Quantity Purchased *(in TJ)*	Quantity Sold [(A)] *(in TJ)*	Ending Balance *(in TJ)*		Biomethane Purchases *(in TJ)*	Biomethane Sales *(in TJ)*	Age of Inventory Sold *(Month)*
Jan-14	99.01	5.77	(11.98)	92.79		207.81	(115.02)	11
Feb-14	92.79	7.71	(13.26)	87.24		215.52	(128.28)	11
Mar-14	87.24	8.75	(11.07)	84.93		224.27	(139.34)	10
Apr-14	84.93	9.68	(7.58)	87.03		233.95	(146.92)	10
May-14	87.03	10.09	(5.08)	92.04		244.05	(152.00)	10
Jun-14	92.04	8.32	(4.38)	95.99		252.37	(156.38)	11
Jul-14	95.99	8.69	(4.01)	100.67		261.06	(160.39)	11
Aug-14	100.67	9.24	(9.80)	100.11		270.30	(170.19)	11
Sep-14	100.11	9.85	(10.26)	99.70		280.15	(180.45)	11
Oct-14	99.70	9.18	(11.31)	97.58		289.34	(191.76)	11
Nov-14	97.58	8.01	(16.59)	89.00		297.35	(208.35)	9
Dec-14	89.00	8.67	(17.75)	79.91		306.02	(226.10)	8
Jan-15	79.91	7.81	(17.29)	70.43		313.83	(243.40)	8
Feb-15	70.43	8.31	(14.80)	63.94		322.14	(258.19)	7
Mar-15	63.94	13.27	(13.88)	63.33		335.41	(272.08)	6
Apr-15	63.33	12.84	(12.68)	63.49		348.24	(284.75)	5
May-15	63.49	12.93	(9.24)	67.19		361.17	(293.99)	5
Jun-15	67.19	12.05	(3.58)	75.66		373.22	(297.57)	5
Jul-15	75.66	11.22	(14.31)	72.57		384.45	(311.88)	5
Aug-15	72.57	12.37	(8.84)	76.10		396.82	(320.72)	6
Sep-15	76.10	11.63	(9.72)	78.01		408.45	(330.43)	6
Oct-15	78.01	10.80	(11.08)	77.73		419.24	(341.51)	6

(A) Including any adjustments reported within the schedule at Page 1 of this report. June 2015 sales quantity was understated by 5.5 TJ.

ERICA M. HAMILTON
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

LETTER NO. L-XX-15

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102
Log No. xxxx

DRAFT ORDER

VIA E-MAIL

November xx, 2015

gas.regulatory.affairs@fortisbc.com

Ms. Diane Roy
Director, Regulatory Services
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Ms. Roy:

Re: FortisBC Energy Inc.
Biomethane Variance Account (BVA) and Biomethane Energy Recovery Charge (BERC)
2015 Fourth Quarter Report

Further to your November 13, 2015, filing of the 2015 Fourth Quarter Report on the BVA and BERC (the Report). The Commission acknowledges receipt of the Report and accepts the recommendation that the BERC rate remain unchanged at January 1, 2016.

The Commission will hold confidential the information in Tab 1, Page 4.1C, 4.2C, and 4.3C of the Report.

Yours truly,

Erica M. Hamilton
Commission Secretary

Attachment 47.3

CustomerID	Date	Biogas Blending Level (%)	Premium
1	41913	1_	8.7942
2	41913	1_	8.7942
3	41913	1_	8.7942
4	41913	1_	8.7942
5	41913	1_	8.7942
6	41913	1_	8.7942
7	41913	1_	8.7942
8	41913	1_	8.7942
9	41913	1_	8.7942
10	41913	1_	8.7942
11	41913	1_	8.7942
12	41913	1_	8.7942
13	41913	1_	8.7942
14	41913	1_	8.7942
15	41913	1_	8.7942
16	41913	1_	8.7942
17	41913	1_	8.7942
18	41913	1_	8.7942
19	41913	1_	8.7942
20	41913	1_	8.7942
21	41913	1_	8.7942
22	41913	1_	8.7942
23	41913	1_	8.7942
24	41913	1_	8.7942
25	41913	1_	8.7942
26	41913	1_	8.7942
27	41913	1_	8.7942
28	41913	1_	8.7942
29	41913	1_	8.7942
30	41913	1_	8.7942
31	41913	1_	8.7942
32	41913	1_	8.7942
33	41913	1_	8.7942
34	41944	1_	8.7942
35	41944	1_	8.7942
36	41944	1_	8.7942
37	41944	1_	8.7942
38	41944	1_	8.7942
39	41944	1_	8.7942
40	41944	1_	8.7942
41	41944	1_	8.7942
42	41944	1_	8.7942
43	41944	1_	8.7942
44	41944	1_	8.7942

CustomerID	Date	Biogas Blending Level (%)	Premium
45	41944	1_	8.7942
46	41944	1_	8.7942
47	41974	1_	8.7942
48	41974	1_	8.7942
49	41974	1_	8.7942
50	41974	1_	8.7942
51	41974	1_	8.7942
52	42005	1_	9.1432
53	42005	1_	9.1432
54	42005	1_	9.1432
55	42005	1_	9.1432
56	42005	1_	9.1432
57	42005	1_	9.1432
58	42005	1_	9.1432
59	42036	1_	9.1432
60	42036	1_	9.1432
61	42036	1_	9.1432
62	42036	1_	9.1432
63	42036	1_	9.1432
64	42036	1_	9.1432
65	42064	1_	9.1432
66	42064	1_	9.1432
67	42064	1_	9.1432
68	42095	1_	10.4382
69	42095	1_	10.4382
70	42095	1_	10.4382
71	42125	1_	10.4382
72	42156	1_	10.4382
73	42156	1_	10.4382
74	42156	1_	10.4382
75	42156	1_	10.4382
76	42186	1_	10.4382
77	42186	1_	10.4382
78	42186	1_	10.4382
79	42186	1_	10.4382
80	42186	1_	10.4382
81	42186	1_	10.4382
82	42186	1_	10.4382
83	42186	1_	10.4382
84	41913	0.5_	8.7942
85	41913	0.5_	8.7942
86	41913	0.5_	8.7942
87	41913	0.5_	8.7942
88	41913	0.5_	8.7942

CustomerID	Date	Biogas Blending Level (%)	Premium
89	41913	0.5_	8.7942
90	41913	0.5_	8.7942
91	41913	0.5_	8.7942
92	41913	0.5_	8.7942
93	41913	0.5_	8.7942
94	41913	0.5_	8.7942
95	41913	0.5_	8.7942
96	41913	0.5_	8.7942
97	41913	0.5_	8.7942
98	41913	0.5_	8.7942
99	41913	0.5_	8.7942
100	41913	0.5_	8.7942
101	41913	0.5_	8.7942
102	41913	0.5_	8.7942
103	41913	0.5_	8.7942
104	41944	0.5_	8.7942
105	41944	0.5_	8.7942
106	41944	0.5_	8.7942
107	41944	0.5_	8.7942
108	41944	0.5_	8.7942
109	41944	0.5_	8.7942
110	41944	0.5_	8.7942
111	41944	0.5_	8.7942
112	41944	0.5_	8.7942
113	41944	0.5_	8.7942
114	41944	0.5_	8.7942
115	41944	0.5_	8.7942
116	41944	0.5_	8.7942
117	41944	0.5_	8.7942
118	41944	0.5_	8.7942
119	41944	0.5_	8.7942
120	41944	0.5_	8.7942
121	41974	0.5_	8.7942
122	41974	0.5_	8.7942
123	42005	0.5_	9.1432
124	42005	0.5_	9.1432
125	42005	0.5_	9.1432
126	42005	0.5_	9.1432
127	42005	0.5_	9.1432
128	42005	0.5_	9.1432
129	42005	0.5_	9.1432
130	42005	0.5_	9.1432
131	42005	0.5_	9.1432
132	42005	0.5_	9.1432

CustomerID	Date	Biogas Blending Level (%)	Premium
133	42036	0.5_	9.1432
134	42036	0.5_	9.1432
135	42064	0.5_	9.1432
136	42064	0.5_	9.1432
137	42064	0.5_	9.1432
138	42095	0.5_	10.4382
139	42095	0.5_	10.4382
140	42095	0.5_	10.4382
141	42095	0.5_	10.4382
142	42125	0.5_	10.4382
143	42125	0.5_	10.4382
144	42125	0.5_	10.4382
145	42125	0.5_	10.4382
146	42156	0.5_	10.4382
147	42156	0.5_	10.4382
148	42156	0.5_	10.4382
149	42156	0.5_	10.4382
150	42156	0.5_	10.4382
151	42156	0.5_	10.4382
152	42156	0.5_	10.4382
153	42186	0.5_	10.4382
154	42186	0.5_	10.4382
155	42186	0.5_	10.4382
156	42186	0.5_	10.4382
157	42186	0.5_	10.4382
158	42186	0.5_	10.4382
159	42186	0.5_	10.4382
160	41913	0.25_	8.7942
161	41913	0.25_	8.7942
162	41913	0.25_	8.7942
163	41913	0.25_	8.7942
164	41913	0.25_	8.7942
165	41913	0.25_	8.7942
166	41913	0.25_	8.7942
167	41913	0.25_	8.7942
168	41913	0.25_	8.7942
169	41913	0.25_	8.7942
170	41913	0.25_	8.7942
171	41913	0.25_	8.7942
172	41913	0.25_	8.7942
173	41913	0.25_	8.7942
174	41913	0.25_	8.7942
175	41913	0.25_	8.7942
176	41913	0.25_	8.7942

CustomerID	Date	Biogas Blending Level (%)	Premium
177	41913	0.25_	8.7942
178	41913	0.25_	8.7942
179	41913	0.25_	8.7942
180	41913	0.25_	8.7942
181	41913	0.25_	8.7942
182	41913	0.25_	8.7942
183	41913	0.25_	8.7942
184	41913	0.25_	8.7942
185	41913	0.25_	8.7942
186	41913	0.25_	8.7942
187	41913	0.25_	8.7942
188	41913	0.25_	8.7942
189	41913	0.25_	8.7942
190	41913	0.25_	8.7942
191	41913	0.25_	8.7942
192	41913	0.25_	8.7942
193	41913	0.25_	8.7942
194	41913	0.25_	8.7942
195	41913	0.25_	8.7942
196	41913	0.25_	8.7942
197	41913	0.25_	8.7942
198	41913	0.25_	8.7942
199	41913	0.25_	8.7942
200	41913	0.25_	8.7942
201	41913	0.25_	8.7942
202	41913	0.25_	8.7942
203	41913	0.25_	8.7942
204	41944	0.25_	8.7942
205	41944	0.25_	8.7942
206	41944	0.25_	8.7942
207	41944	0.25_	8.7942
208	41944	0.25_	8.7942
209	41944	0.25_	8.7942
210	41944	0.25_	8.7942
211	41944	0.25_	8.7942
212	41944	0.25_	8.7942
213	41944	0.25_	8.7942
214	41944	0.25_	8.7942
215	41944	0.25_	8.7942
216	41944	0.25_	8.7942
217	41944	0.25_	8.7942
218	41944	0.25_	8.7942
219	41944	0.25_	8.7942
220	41944	0.25_	8.7942

CustomerID	Date	Biogas Blending Level (%)	Premium
221	41944	0.25_	8.7942
222	41944	0.25_	8.7942
223	41944	0.25_	8.7942
224	41944	0.25_	8.7942
225	41944	0.25_	8.7942
226	41944	0.25_	8.7942
227	41944	0.25_	8.7942
228	41944	0.25_	8.7942
229	41944	0.25_	8.7942
230	41944	0.25_	8.7942
231	41944	0.25_	8.7942
232	41944	0.25_	8.7942
233	41944	0.25_	8.7942
234	41944	0.25_	8.7942
235	41944	0.25_	8.7942
236	41944	0.25_	8.7942
237	41944	0.25_	8.7942
238	41944	0.25_	8.7942
239	41944	0.25_	8.7942
240	41944	0.25_	8.7942
241	41944	0.25_	8.7942
242	41944	0.25_	8.7942
243	41974	0.25_	8.7942
244	41974	0.25_	8.7942
245	41974	0.25_	8.7942
246	41974	0.25_	8.7942
247	41974	0.25_	8.7942
248	41974	0.25_	8.7942
249	41974	0.25_	8.7942
250	42005	0.25_	9.1432
251	42005	0.25_	9.1432
252	42005	0.25_	9.1432
253	42005	0.25_	9.1432
254	42005	0.25_	9.1432
255	42005	0.25_	9.1432
256	42005	0.25_	9.1432
257	42005	0.25_	9.1432
258	42005	0.25_	9.1432
259	42005	0.25_	9.1432
260	42005	0.25_	9.1432
261	42005	0.25_	9.1432
262	42005	0.25_	9.1432
263	42005	0.25_	9.1432
264	42036	0.25_	9.1432

CustomerID	Date	Biogas Blending Level (%)	Premium
265	42036	0.25_	9.1432
266	42036	0.25_	9.1432
267	42036	0.25_	9.1432
268	42036	0.25_	9.1432
269	42036	0.25_	9.1432
270	42036	0.25_	9.1432
271	42036	0.25_	9.1432
272	42064	0.25_	9.1432
273	42064	0.25_	9.1432
274	42064	0.25_	9.1432
275	42064	0.25_	9.1432
276	42064	0.25_	9.1432
277	42064	0.25_	9.1432
278	42064	0.25_	9.1432
279	42064	0.25_	9.1432
280	42064	0.25_	9.1432
281	42064	0.25_	9.1432
282	42095	0.25_	10.4382
283	42095	0.25_	10.4382
284	42095	0.25_	10.4382
285	42095	0.25_	10.4382
286	42095	0.25_	10.4382
287	42095	0.25_	10.4382
288	42095	0.25_	10.4382
289	42125	0.25_	10.4382
290	42125	0.25_	10.4382
291	42125	0.25_	10.4382
292	42125	0.25_	10.4382
293	42125	0.25_	10.4382
294	42125	0.25_	10.4382
295	42156	0.25_	10.4382
296	42156	0.25_	10.4382
297	42156	0.25_	10.4382
298	42156	0.25_	10.4382
299	42156	0.25_	10.4382
300	42186	0.25_	10.4382
301	42186	0.25_	10.4382
302	42186	0.25_	10.4382
303	42186	0.25_	10.4382
304	42186	0.25_	10.4382
305	42186	0.25_	10.4382
306	42186	0.25_	10.4382
307	42186	0.25_	10.4382
308	42186	0.25_	10.4382

CustomerID	Date	Biogas Blending Level (%)	Premium
309	42186	0.25_	10.4382
310	42186	0.25_	10.4382
311	42186	0.25_	10.4382
312	42186	0.25_	10.4382
313	42186	0.25_	10.4382
314	41913	0.1_	8.7942
315	41913	0.1_	8.7942
316	41913	0.1_	8.7942
317	41913	0.1_	8.7942
318	41913	0.1_	8.7942
319	41913	0.1_	8.7942
320	41913	0.1_	8.7942
321	41913	0.1_	8.7942
322	41913	0.1_	8.7942
323	41913	0.1_	8.7942
324	41913	0.1_	8.7942
325	41913	0.1_	8.7942
326	41913	0.1_	8.7942
327	41913	0.1_	8.7942
328	41913	0.1_	8.7942
329	41913	0.1_	8.7942
330	41913	0.1_	8.7942
331	41913	0.1_	8.7942
332	41913	0.1_	8.7942
333	41913	0.1_	8.7942
334	41913	0.1_	8.7942
335	41913	0.1_	8.7942
336	41913	0.1_	8.7942
337	41913	0.1_	8.7942
338	41913	0.1_	8.7942
339	41913	0.1_	8.7942
340	41913	0.1_	8.7942
341	41913	0.1_	8.7942
342	41913	0.1_	8.7942
343	41913	0.1_	8.7942
344	41913	0.1_	8.7942
345	41913	0.1_	8.7942
346	41913	0.1_	8.7942
347	41913	0.1_	8.7942
348	41913	0.1_	8.7942
349	41913	0.1_	8.7942
350	41913	0.1_	8.7942
351	41913	0.1_	8.7942
352	41913	0.1_	8.7942

CustomerID	Date	Biogas Blending Level (%)	Premium
353	41913	0.1_	8.7942
354	41913	0.1_	8.7942
355	41913	0.1_	8.7942
356	41913	0.1_	8.7942
357	41913	0.1_	8.7942
358	41913	0.1_	8.7942
359	41913	0.1_	8.7942
360	41913	0.1_	8.7942
361	41913	0.1_	8.7942
362	41913	0.1_	8.7942
363	41913	0.1_	8.7942
364	41913	0.1_	8.7942
365	41913	0.1_	8.7942
366	41913	0.1_	8.7942
367	41913	0.1_	8.7942
368	41913	0.1_	8.7942
369	41913	0.1_	8.7942
370	41913	0.1_	8.7942
371	41913	0.1_	8.7942
372	41913	0.1_	8.7942
373	41913	0.1_	8.7942
374	41913	0.1_	8.7942
375	41913	0.1_	8.7942
376	41913	0.1_	8.7942
377	41913	0.1_	8.7942
378	41913	0.1_	8.7942
379	41944	0.1_	8.7942
380	41944	0.1_	8.7942
381	41944	0.1_	8.7942
382	41944	0.1_	8.7942
383	41944	0.1_	8.7942
384	41944	0.1_	8.7942
385	41944	0.1_	8.7942
386	41944	0.1_	8.7942
387	41944	0.1_	8.7942
388	41944	0.1_	8.7942
389	41944	0.1_	8.7942
390	41944	0.1_	8.7942
391	41944	0.1_	8.7942
392	41944	0.1_	8.7942
393	41944	0.1_	8.7942
394	41944	0.1_	8.7942
395	41944	0.1_	8.7942
396	41944	0.1_	8.7942

CustomerID	Date	Biogas Blending Level (%)	Premium
397	41944	0.1_	8.7942
398	41944	0.1_	8.7942
399	41944	0.1_	8.7942
400	41944	0.1_	8.7942
401	41944	0.1_	8.7942
402	41944	0.1_	8.7942
403	41944	0.1_	8.7942
404	41944	0.1_	8.7942
405	41944	0.1_	8.7942
406	41944	0.1_	8.7942
407	41944	0.1_	8.7942
408	41944	0.1_	8.7942
409	41944	0.1_	8.7942
410	41944	0.1_	8.7942
411	41974	0.1_	8.7942
412	41974	0.1_	8.7942
413	41974	0.1_	8.7942
414	41974	0.1_	8.7942
415	41974	0.1_	8.7942
416	41974	0.1_	8.7942
417	41974	0.1_	8.7942
418	41974	0.1_	8.7942
419	41974	0.1_	8.7942
420	41974	0.1_	8.7942
421	41974	0.1_	8.7942
422	41974	0.1_	8.7942
423	41974	0.1_	8.7942
424	41974	0.1_	8.7942
425	41974	0.1_	8.7942
426	41974	0.1_	8.7942
427	41974	0.1_	8.7942
428	41974	0.1_	8.7942
429	41974	0.1_	8.7942
430	41974	0.1_	8.7942
431	41974	0.1_	8.7942
432	41974	0.1_	8.7942
433	41974	0.1_	8.7942
434	42005	0.1_	9.1432
435	42005	0.1_	9.1432
436	42005	0.1_	9.1432
437	42005	0.1_	9.1432
438	42005	0.1_	9.1432
439	42005	0.1_	9.1432
440	42005	0.1_	9.1432

CustomerID	Date	Biogas Blending Level (%)	Premium
441	42005	0.1_	9.1432
442	42005	0.1_	9.1432
443	42005	0.1_	9.1432
444	42005	0.1_	9.1432
445	42005	0.1_	9.1432
446	42005	0.1_	9.1432
447	42005	0.1_	9.1432
448	42005	0.1_	9.1432
449	42005	0.1_	9.1432
450	42005	0.1_	9.1432
451	42005	0.1_	9.1432
452	42005	0.1_	9.1432
453	42005	0.1_	9.1432
454	42005	0.1_	9.1432
455	42005	0.1_	9.1432
456	42005	0.1_	9.1432
457	42005	0.1_	9.1432
458	42005	0.1_	9.1432
459	42005	0.1_	9.1432
460	42005	0.1_	9.1432
461	42036	0.1_	9.1432
462	42036	0.1_	9.1432
463	42036	0.1_	9.1432
464	42036	0.1_	9.1432
465	42036	0.1_	9.1432
466	42036	0.1_	9.1432
467	42036	0.1_	9.1432
468	42036	0.1_	9.1432
469	42036	0.1_	9.1432
470	42036	0.1_	9.1432
471	42036	0.1_	9.1432
472	42036	0.1_	9.1432
473	42036	0.1_	9.1432
474	42036	0.1_	9.1432
475	42036	0.1_	9.1432
476	42036	0.1_	9.1432
477	42036	0.1_	9.1432
478	42036	0.1_	9.1432
479	42036	0.1_	9.1432
480	42036	0.1_	9.1432
481	42036	0.1_	9.1432
482	42064	0.1_	9.1432
483	42064	0.1_	9.1432
484	42064	0.1_	9.1432

CustomerID	Date	Biogas Blending Level (%)	Premium
485	42064	0.1_	9.1432
486	42064	0.1_	9.1432
487	42064	0.1_	9.1432
488	42064	0.1_	9.1432
489	42064	0.1_	9.1432
490	42064	0.1_	9.1432
491	42064	0.1_	9.1432
492	42064	0.1_	9.1432
493	42064	0.1_	9.1432
494	42064	0.1_	9.1432
495	42064	0.1_	9.1432
496	42064	0.1_	9.1432
497	42064	0.1_	9.1432
498	42064	0.1_	9.1432
499	42095	0.1_	10.4382
500	42095	0.1_	10.4382
501	42095	0.1_	10.4382
502	42095	0.1_	10.4382
503	42095	0.1_	10.4382
504	42095	0.1_	10.4382
505	42095	0.1_	10.4382
506	42095	0.1_	10.4382
507	42095	0.1_	10.4382
508	42095	0.1_	10.4382
509	42095	0.1_	10.4382
510	42095	0.1_	10.4382
511	42095	0.1_	10.4382
512	42095	0.1_	10.4382
513	42095	0.1_	10.4382
514	42095	0.1_	10.4382
515	42125	0.1_	10.4382
516	42125	0.1_	10.4382
517	42125	0.1_	10.4382
518	42125	0.1_	10.4382
519	42125	0.1_	10.4382
520	42125	0.1_	10.4382
521	42125	0.1_	10.4382
522	42125	0.1_	10.4382
523	42125	0.1_	10.4382
524	42125	0.1_	10.4382
525	42125	0.1_	10.4382
526	42125	0.1_	10.4382
527	42125	0.1_	10.4382
528	42125	0.1_	10.4382

CustomerID	Date	Biogas Blending Level (%)	Premium
529	42125	0.1_	10.4382
530	42125	0.1_	10.4382
531	42125	0.1_	10.4382
532	42125	0.1_	10.4382
533	42125	0.1_	10.4382
534	42125	0.1_	10.4382
535	42125	0.1_	10.4382
536	42125	0.1_	10.4382
537	42125	0.1_	10.4382
538	42125	0.1_	10.4382
539	42125	0.1_	10.4382
540	42125	0.1_	10.4382
541	42125	0.1_	10.4382
542	42125	0.1_	10.4382
543	42125	0.1_	10.4382
544	42156	0.1_	10.4382
545	42156	0.1_	10.4382
546	42156	0.1_	10.4382
547	42156	0.1_	10.4382
548	42156	0.1_	10.4382
549	42156	0.1_	10.4382
550	42156	0.1_	10.4382
551	42156	0.1_	10.4382
552	42156	0.1_	10.4382
553	42156	0.1_	10.4382
554	42156	0.1_	10.4382
555	42156	0.1_	10.4382
556	42156	0.1_	10.4382
557	42156	0.1_	10.4382
558	42156	0.1_	10.4382
559	42156	0.1_	10.4382
560	42156	0.1_	10.4382
561	42156	0.1_	10.4382
562	42156	0.1_	10.4382
563	42156	0.1_	10.4382
564	42156	0.1_	10.4382
565	42156	0.1_	10.4382
566	42156	0.1_	10.4382
567	42156	0.1_	10.4382
568	42156	0.1_	10.4382
569	42156	0.1_	10.4382
570	42156	0.1_	10.4382
571	42156	0.1_	10.4382
572	42156	0.1_	10.4382

CustomerID	Date	Biogas Blending Level (%)	Premium
573	42186	0.1_	10.4382
574	42186	0.1_	10.4382
575	42186	0.1_	10.4382
576	42186	0.1_	10.4382
577	42186	0.1_	10.4382
578	42186	0.1_	10.4382
579	42186	0.1_	10.4382
580	42186	0.1_	10.4382
581	42186	0.1_	10.4382
582	42186	0.1_	10.4382
583	42186	0.1_	10.4382
584	42186	0.1_	10.4382
585	42186	0.1_	10.4382
586	42186	0.1_	10.4382
587	42186	0.1_	10.4382
588	42186	0.1_	10.4382
589	42186	0.1_	10.4382
590	42186	0.1_	10.4382
591	42186	0.1_	10.4382
592	42186	0.1_	10.4382
593	42186	0.1_	10.4382
594	42186	0.1_	10.4382
595	42186	0.1_	10.4382
596	42186	0.1_	10.4382
597	42186	0.1_	10.4382
598	42186	0.1_	10.4382
599	42186	0.1_	10.4382
600	42186	0.1_	10.4382
601	42186	0.1_	10.4382
602	41913	0.05_	8.7942
603	41913	0.05_	8.7942
604	41913	0.05_	8.7942
605	41913	0.05_	8.7942
606	41913	0.05_	8.7942
607	41913	0.05_	8.7942
608	41913	0.05_	8.7942
609	41913	0.05_	8.7942
610	41913	0.05_	8.7942
611	41913	0.05_	8.7942
612	41944	0.05_	8.7942
613	41944	0.05_	8.7942
614	41944	0.05_	8.7942
615	41944	0.05_	8.7942
616	41944	0.05_	8.7942

CustomerID	Date	Biogas Blending Level (%)	Premium
617	41944	0.05_	8.7942
618	41944	0.05_	8.7942
619	41944	0.05_	8.7942
620	41944	0.05_	8.7942
621	41944	0.05_	8.7942
622	41944	0.05_	8.7942
623	41944	0.05_	8.7942
624	41974	0.05_	8.7942
625	41974	0.05_	8.7942
626	41974	0.05_	8.7942
627	41974	0.05_	8.7942
628	41974	0.05_	8.7942
629	42005	0.05_	9.1432
630	42005	0.05_	9.1432
631	42005	0.05_	9.1432
632	42005	0.05_	9.1432
633	42005	0.05_	9.1432
634	42005	0.05_	9.1432
635	42005	0.05_	9.1432
636	42005	0.05_	9.1432
637	42005	0.05_	9.1432
638	42005	0.05_	9.1432
639	42005	0.05_	9.1432
640	42005	0.05_	9.1432
641	42005	0.05_	9.1432
642	42005	0.05_	9.1432
643	42005	0.05_	9.1432
644	42005	0.05_	9.1432
645	42036	0.05_	9.1432
646	42036	0.05_	9.1432
647	42036	0.05_	9.1432
648	42036	0.05_	9.1432
649	42036	0.05_	9.1432
650	42036	0.05_	9.1432
651	42036	0.05_	9.1432
652	42036	0.05_	9.1432
653	42036	0.05_	9.1432
654	42036	0.05_	9.1432
655	42036	0.05_	9.1432
656	42036	0.05_	9.1432
657	42036	0.05_	9.1432
658	42036	0.05_	9.1432
659	42036	0.05_	9.1432
660	42036	0.05_	9.1432

CustomerID	Date	Biogas Blending Level (%)	Premium
661	42064	0.05_	9.1432
662	42064	0.05_	9.1432
663	42064	0.05_	9.1432
664	42064	0.05_	9.1432
665	42064	0.05_	9.1432
666	42064	0.05_	9.1432
667	42064	0.05_	9.1432
668	42064	0.05_	9.1432
669	42064	0.05_	9.1432
670	42064	0.05_	9.1432
671	42064	0.05_	9.1432
672	42064	0.05_	9.1432
673	42064	0.05_	9.1432
674	42095	0.05_	10.4382
675	42095	0.05_	10.4382
676	42095	0.05_	10.4382
677	42095	0.05_	10.4382
678	42095	0.05_	10.4382
679	42095	0.05_	10.4382
680	42095	0.05_	10.4382
681	42095	0.05_	10.4382
682	42095	0.05_	10.4382
683	42095	0.05_	10.4382
684	42095	0.05_	10.4382
685	42095	0.05_	10.4382
686	42095	0.05_	10.4382
687	42095	0.05_	10.4382
688	42095	0.05_	10.4382
689	42095	0.05_	10.4382
690	42095	0.05_	10.4382
691	42095	0.05_	10.4382
692	42095	0.05_	10.4382
693	42125	0.05_	10.4382
694	42125	0.05_	10.4382
695	42125	0.05_	10.4382
696	42125	0.05_	10.4382
697	42125	0.05_	10.4382
698	42125	0.05_	10.4382
699	42125	0.05_	10.4382
700	42125	0.05_	10.4382
701	42125	0.05_	10.4382
702	42125	0.05_	10.4382
703	42125	0.05_	10.4382
704	42125	0.05_	10.4382

CustomerID	Date	Biogas Blending Level (%)	Premium
705	42125	0.05_	10.4382
706	42125	0.05_	10.4382
707	42125	0.05_	10.4382
708	42125	0.05_	10.4382
709	42125	0.05_	10.4382
710	42125	0.05_	10.4382
711	42125	0.05_	10.4382
712	42125	0.05_	10.4382
713	42125	0.05_	10.4382
714	42125	0.05_	10.4382
715	42125	0.05_	10.4382
716	42125	0.05_	10.4382
717	42125	0.05_	10.4382
718	42125	0.05_	10.4382
719	42125	0.05_	10.4382
720	42125	0.05_	10.4382
721	42125	0.05_	10.4382
722	42125	0.05_	10.4382
723	42156	0.05_	10.4382
724	42156	0.05_	10.4382
725	42156	0.05_	10.4382
726	42156	0.05_	10.4382
727	42156	0.05_	10.4382
728	42156	0.05_	10.4382
729	42156	0.05_	10.4382
730	42156	0.05_	10.4382
731	42156	0.05_	10.4382
732	42156	0.05_	10.4382
733	42156	0.05_	10.4382
734	42156	0.05_	10.4382
735	42156	0.05_	10.4382
736	42156	0.05_	10.4382
737	42156	0.05_	10.4382
738	42156	0.05_	10.4382
739	42156	0.05_	10.4382
740	42156	0.05_	10.4382
741	42156	0.05_	10.4382
742	42156	0.05_	10.4382
743	42156	0.05_	10.4382
744	42186	0.05_	10.4382
745	42186	0.05_	10.4382
746	42186	0.05_	10.4382
747	42186	0.05_	10.4382
748	42186	0.05_	10.4382

CustomerID	Date	Biogas Blending Level (%)	Premium
749	42186	0.05_	10.4382
750	42186	0.05_	10.4382
751	42186	0.05_	10.4382
752	42186	0.05_	10.4382
753	42186	0.05_	10.4382
754	42186	0.05_	10.4382
755	42186	0.05_	10.4382
756	42186	0.05_	10.4382
757	42186	0.05_	10.4382
758	42186	0.05_	10.4382
759	42186	0.05_	10.4382
760	42186	0.05_	10.4382
761	42186	0.05_	10.4382
762	42186	0.05_	10.4382
763	42186	0.05_	10.4382
764	42186	0.05_	10.4382
765	42186	0.05_	10.4382
766	42186	0.05_	10.4382
767	42186	0.05_	10.4382

Attachment 51.1

FORTISBC ENERGY INC.
2015 BERC Rate Methodology Application
Financial Analysis

Proposed Alternative

Schedule	Description
1	Forecast Biomethane Variance Account- Activity and Closing Balance
2	Forecast Demand and Recoveries by Rate Schedule at Market-Based BERC Rate
3	Forecast Impacts at Market-Based BERC Rate
4	Forecast Cost-Based BERC Rate
5	Summary of Alternatives Considered

FORTISBC ENERGY INC.
2015 BERC Rate Methodology Application
Forecast Biomethane Variance Account- Activity and Closing Balance

Schedule 1

Line No.	Particulars	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
1	**Biomethane Variance Account**												
2	Opening Balance (after tax)	$ 1,097	$ 1,221	$ 2,821	$ 7,511	$ 15,467	$ 20,896	$ 19,446	$ 14,395	$ 11,872	$ 14,698	$ 20,028	
3	Additions - Tax Effected												
4	Cost of Biomethane	1,999	3,349	7,119	10,841	12,594	14,399	16,277	16,472	16,658	16,846	17,039	
5	Operating and Maintenance Expense	618	959	1,644	1,919	1,980	2,043	2,087	2,108	2,129	2,151	2,173	
6	Property Tax Expense	13	20	20	21	24	28	33	41	47	61	69	
7	Earned Return - Debt Component	252	265	293	876	884	892	897	876	829	782	734	
8	Subtotal	2,881	4,593	9,075	13,657	15,483	17,362	19,294	19,498	19,663	19,840	20,015	
9	Tax Offset	(749)	(1,194)	(2,360)	(3,551)	(4,026)	(4,514)	(5,017)	(5,069)	(5,112)	(5,158)	(5,204)	
10	Total Additions - Tax Effected	2,132	3,399	6,716	10,106	11,457	12,848	14,278	14,428	14,551	14,681	14,811	
11	Additions - Non-Tax Effected												
12	Depreciation	133	371	399	1,173	1,212	1,251	1,290	1,329	1,329	1,329	1,329	
13	Negative Salvage Provision Expense	-	-	1	4	5	6	7	7	7	7	7	
14	Notional Income Tax	(701)	(275)	(1,208)	(1,233)	(305)	156	384	486	524	547	555	
15	Earned Return - Equity Component	233	253	279	835	843	849	855	835	790	745	700	
16	Subtotal	(335)	349	(529)	779	1,755	2,263	2,536	2,657	2,650	2,628	2,591	
17	Total Additions	1,796	3,748	6,187	10,885	13,212	15,110	16,814	17,086	17,201	17,309	17,402	
18													
19	BERC Recoveries	(2,260)	(1,880)	(2,166)	(2,371)	(2,575)	(2,784)	(3,023)	(3,285)	(3,560)	(3,831)	(4,005)	
20	Tax Offset	588	489	563	617	669	724	786	854	926	996	1,041	
21	Net Recoveries	(1,672)	(1,391)	(1,603)	(1,755)	(1,905)	(2,060)	(2,237)	(2,431)	(2,634)	(2,835)	(2,964)	
22													
23	Aged inventory write-off - non-tax effected	-	-	-	(1,073)	(3,308)	(4,970)	(4,910)	(3,428)	(2,687)	(3,616)	(5,448)	***(29,441)***
24	Tranfer all costs except Supply ending balance	-	(756)	105	(101)	(2,569)	(9,530)	(14,718)	(13,750)	(9,053)	(5,528)	(6,409)	***(62,309)***
25													
26	**BVA Closing Balance (after tax)**	**$ 1,221**	**$ 2,821**	**$ 7,511**	**$ 15,467**	**$ 20,896**	**$ 19,446**	**$ 14,395**	**$ 11,872**	**$ 14,698**	**$ 20,028**	**$ 22,609**	
	(Balance remaining is Ending supply in GJs at current BERC rate)												

FORTISBC ENERGY INC.
2015 BERC Rate Methodology Application
Forecast Demand and Recoveries by Rate Schedule at Market-Based BERC Rate

Schedule 2

Line No.	Particulars	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	**BERC Recoveries/Sales**											
2	**Rate 1:** Residential Volume (GJ)	68,058	74,162	86,459	97,966	108,455	120,317	133,831	148,868	165,598	183,074	193,851
3	BERC Rate $ /GJ	$ 14.414	$ 11.330	$ 11.467	$ 11.600	$ 11.765	$ 11.926	$ 12.194	$ 12.399	$ 12.596	$ 12.679	$ 12.762
4	Recovery from Residential ($000)	$ 981	$ 840	$ 991	$ 1,136	$ 1,276	$ 1,435	$ 1,632	$ 1,846	$ 2,086	$ 2,321	$ 2,474
5												
6	**Rate 2:** Small Commercial Volume	5,390	6,173	6,829	7,121	7,358	7,595	7,840	8,094	8,356	8,627	8,906
7	BERC Rate	$ 14.414	$ 11.330	$ 11.467	$ 11.600	$ 11.765	$ 11.926	$ 12.194	$ 12.399	$ 12.596	$ 12.679	$ 12.762
8	Recovery from Small Commercial ($000)	78	70	78	83	87	91	96	100	105	109	114
9												
10	**Rate 3:** Large Commercial Volume	6,449	6,822	7,330	7,554	7,635	7,703	7,773	7,848	7,924	8,003	8,083
11	BERC Rate	$ 14.414	$ 11.330	$ 11.467	$ 11.600	$ 11.765	$ 11.926	$ 12.194	$ 12.399	$ 12.596	$ 12.679	$ 12.762
12	Recovery from Large Commercial ($000)	93	77	84	88	90	92	95	97	100	101	103
13												
14	**Other On-System Volume (Gas marketer)**	6,716	7,052	7,404	7,775	8,163	8,572	9,000	9,450	9,923	10,419	10,940
15	BERC Rate	$ 14.414	$ 11.330	$ 11.467	$ 11.600	$ 11.765	$ 11.926	$ 12.194	$ 12.399	$ 12.596	$ 12.679	$ 12.762
16	Recovery from Other On-System ($000)	97	80	85	90	96	102	110	117	125	132	140
17												
18	**Transportation Sector/CNG**	-	1,172	2,000	3,000	5,000	5,765	5,765	5,765	5,765	5,765	5,765
19	BERC Rate	$ 14.414	$ 11.330	$ 11.467	$ 11.600	$ 11.765	$ 11.926	$ 12.194	$ 12.399	$ 12.596	$ 12.679	$ 12.762
20	Recovery from Other Off-System ($000)	-	13	23	35	59	69	70	71	73	73	74
21												
22	**Large/Fixed Volume / Cogen**	70,180	77,425	86,388	88,638	89,888	91,138	91,138	92,388	92,388	93,638	93,638
23	BERC Rate	$ 14.414	$ 10.330	$ 10.467	$ 10.600	$ 10.765	$ 10.926	$ 11.194	$ 11.399	$ 11.596	$ 11.679	$ 11.762
24	Recovery from Other Off-System ($000)	1,012	800	904	940	968	996	1,020	1,053	1,071	1,094	1,101
25												
26	Total Sales Volumes (GJ)	156,793	172,806	196,410	212,054	226,499	241,090	255,347	272,413	289,954	309,526	321,183
27	**Total Recoveries ($000)**	$ 2,260	$ 1,880	$ 2,166	$ 2,371	$ 2,575	$ 2,784	$ 3,023	$ 3,285	$ 3,560	$ 3,831	$ 4,005

FORTISBC ENERGY INC.
2015 BERC Rate Methodology Application
Forecast Impacts at Market-Based BERC Rate

Schedule 3

Line No.	Particulars	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1											
2	**Aged Inventory Transfer to Storage and Transport Rates**										
3	GJs > 18 months in age	$ -	$ -	$ 346,070	$ 1,013,201	$ 1,450,737	$ 1,329,116	$ 879,122	$ 656,035	$ 865,401	$ 1,278,282
4	Forecasted Natural Gas Commodity rate	$ 2.83	$ 2.97	$ 3.10	$ 3.27	$ 3.43	$ 3.69	$ 3.90	$ 4.10	$ 4.18	$ 4.26
5	Aged inventory transfer - non-tax effected ($000)	-	-	(1,073)	(3,308)	(4,970)	(4,910)	(3,428)	(2,687)	(3,616)	(5,448)
6	Non-bypass Sales Volume	124,017.9	124,017.9	124,017.9	124,017.9	124,017.9	124,017.9	124,017.9	124,017.9	124,017.9	124,017.9
7	**IMPACT TOTAL CUSTOMERS PER GJ**	$ -	$ -	$ (0.0087)	$ (0.0267)	$ (0.0401)	$ (0.0396)	$ (0.0276)	$ (0.0217)	$ (0.0292)	$ (0.0439)
8	IMPACT % of delivery margin	0.00%	0.00%	0.15%	0.46%	0.69%	0.68%	0.48%	0.37%	0.50%	0.76%
9											
10											
11											
12											
13											
14	**Transfer to Delivery Rates**										
15	Tranfer all costs except Supply ending balance	(756)	105	(101)	(2,569)	(9,530)	(14,718)	(13,750)	(9,053)	(5,528)	(6,409)
16	Non-bypass Sales & Transportation Volume	175,315.3	175,315.3	175,315.3	175,315.3	175,315.3	175,315.3	175,315.3	175,315.3	175,315.3	175,315.3
17	**IMPACT TOTAL CUSTOMERS PER GJ**	$ (0.0043)	$ 0.0006	$ (0.0006)	$ (0.0147)	$ (0.0544)	$ (0.0839)	$ (0.0784)	$ (0.0516)	$ (0.0315)	$ (0.0366)
18	IMPACT % of delivery margin	0.10%	-0.01%	0.01%	0.36%	1.32%	2.04%	1.91%	1.26%	0.77%	0.89%
19											
20		**$ 720,884**	Delivery margin								
21											
22											

FORTISBC ENERGY INC.
2015 BERC Rate Methodology Application
Forecast Cost-Based BERC Rate

Schedule 4

Line No.	Particulars	2016		2017		2018		2019		2020		2021		2022		2023		2024		2025		Notes
1		$000	TJ	$000	TJ	$000	TJ	$000	TJ	$000	TJ	$000	TJ	$000	TJ	$000	TJ	$000	TJ	$000	TJ	
2	**Forecast BVA Balance - Deficit at December 31**																					
3	**Cost (BVA ending balance pre tax)**	$ 1,649		$ 3,813		$ 10,150		$ 20,901		$ 28,238		$ 26,278		$ 19,453		$ 16,043		$ 19,862		$ 27,065		
4	**Quantity unsold end of year**		101.66		246.05		647.48		1,314.61		1,752.15		1,630.53		1,180.54		957.45		1,166.81		1,579.69	Unsold Quantity
5																						
6	**Forecast Costs Incurred in the 12 month period**																					
7	**Cost (Jan 1 to Dec 31 costs incurred)**	$ 4,942		$ 8,546		$ 14,436		$ 17,238		$ 19,624		$ 21,830		$ 22,155		$ 22,313		$ 22,468		$ 22,606		
8	**Quantity (Jan 1 to Dec 31 purchases)**		317.20		597.85		879.19		1,010.11		1,132.67		1,256.09		1,378.44		1,378.44		1,378.44		1,378.44	Purchase Quantity
9																						
10	**Biomethane Available for Sale in the 12-month period**																					
11	**Total Cost to be recovered**	**$ 6,591**	**418.85**	**$ 12,359**	**843.89**	**$ 24,586**	**1,526.67**	**$ 38,139**	**2,324.72**	**$ 47,862**	**2,884.82**	**$ 48,108**	**2,886.62**	**$ 41,608**	**2,558.98**	**$ 38,356**	**2,335.89**	**$ 42,329**	**2,545.26**	**$ 49,671**	**2,958.14**	
12	**Total Quantity**																					
13																						
14	**Cost-Based BERC Rate**		**$ 15.74**		**$ 14.65**		**$ 16.10**		**$ 16.41**		**$ 16.59**		**$ 16.67**		**$ 16.26**		**$ 16.42**		**$ 16.63**		**$ 16.79**	
15			2016 rate		2017 rate		2018 rate		2019 rate		2020 rate		2021 rate		2022 rate		2023 rate		2024 rate		2025 rate	

FORTISBC ENERGY INC.
2015 BERC Rate Methodology Application
Summary of Alternatives Considered

Schedule 5

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total	10 year AVERAGE
1 - STATUS QUO Forecast (Escalating upward) Contract Demand Scenario ($16 to $17 BERC used for sales)												
BVA Closing Balance (after tax)	$ 3,288	$ 8,002	$ 17,409	$ 29,088	$ 42,632	$ 57,382	$ 74,033	$ 90,796	$ 107,666	$ 124,629		
per GJ					$ 0.2432					$ 0.7109		
BERC RATE based on cost of service	$ 15.73	$ 14.88	$ 15.61	$ 16.31	$ 16.81	$ 17.00	$ 17.20	$ 17.37	$ 17.50	$ 17.61		
Customer impact based on 90 GJS					**$ 21.89**					**$ 63.98**		
2 - Forecast (Escalating upward) Contract Demand Scenario w/ WRITE OFF of AGED INVENTORY and difference between the BERC Rate and CCRA												
BVA Closing Balance (after tax)	$ 3,288	$ 8,002	$ 9,050	$ 5,991	$ 4,983	$ 7,110	$ 12,477	$ 16,177	$ 13,805	$ 9,287		
BERC RATE based on cost of service	$ 15.73	$ 14.88	$ 15.61	$ 11.79	$ 9.34	$ 10.15	$ 13.77	$ 17.56	$ 16.88	$ 13.32		
Stale dated write-off > 18 months old	-	-	(1,661)	(4,200)	(5,595)	(4,999)	(3,315)	(3,067)	(4,804)	(7,038)	**(34,679)**	
per GJ to MCRA	-	-	(0.0134)	(0.0339)	(0.0451)	(0.0403)	(0.0267)	(0.0247)	(0.0387)	(0.0567)		(0.0280)
Difference between the average cost of supply and CCRA rate	-	-	(6,699)	(10,965)	(9,654)	(8,738)	(8,389)	(10,079)	(14,602)	(14,963)	**(84,088)**	
per GJ - all delivery	-	-	(0.0382)	(0.0625)	(0.0551)	(0.0498)	(0.0478)	(0.0575)	(0.0833)	(0.0853)		(0.0480)
Customer impact based on 90 GJs												**$ 6.83**
3 - PROPOSED - Lower Price Contract Demand Scenario (CCRA + $7.50/$8.50 BERC used for sales)												
BVA Closing Balance (after tax)	$ 2,822	$ 7,510	$ 15,466	$ 20,897	$ 19,446	$ 14,395	$ 11,872	$ 14,698	$ 20,028	$ 22,609		
BERC RATE based on cost of service	$ 15.73	$ 14.64	$ 16.11	$ 16.41	$ 16.60	$ 16.67	$ 16.26	$ 16.42	$ 16.63	$ 16.79		
BERC RATE CHARGED to Customers	$ 11.33	$ 11.47	$ 11.60	$ 11.77	$ 11.93	$ 12.19	$ 12.40	$ 12.60	$ 12.68	$ 12.76		
BERC RATE CHARGED to Customers Long Term	$ 10.33	$ 10.47	$ 10.60	$ 10.77	$ 10.93	$ 11.19	$ 11.40	$ 11.60	$ 11.68	$ 11.76		
Stale dated write-off > 18 months old	-	-	(1,073)	(3,308)	(4,970)	(4,910)	(3,428)	(2,687)	(3,616)	(5,448)	**(29,441)**	
per GJ to MCRA	-	-	(0.0087)	(0.0267)	(0.0401)	(0.0396)	(0.0276)	(0.0217)	(0.0292)	(0.0439)		(0.0237)
Tranfer all costs except Supply ending balance	(751)	113	(107)	(2,575)	(9,538)	(14,718)	(13,750)	(9,053)	(5,528)	(6,409)	**(62,316)**	
per GJ - all delivery	(0.0043)	0.0006	(0.0006)	(0.0147)	(0.0544)	(0.0839)	(0.0784)	(0.0516)	(0.0315)	(0.0366)		(0.0355)
Customer impact based on 90 GJS												**$ 5.34**
4 - Green Portfolio												
BVA Closing Balance (after tax)	$ 4,629	$ 10,467	$ 21,011	$ 33,875	$ 48,631	$ 65,066	$ 83,056	$ 101,176	$ 119,421	$ 137,773		
Impact to customers	$ 0.0373	$ 0.0471	$ 0.0850	$ 0.1037	$ 0.1190	$ 0.1700	$ 0.1922	$ 0.2311	$ 0.2508	$ 0.2669		$ 0.1503
Customer impact based on 90 GJS												**$ 13.53**

Attachment 51.1.1

REFER TO LIVE SPREADSHEET MODELS

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