Diane Roy
Director, Regulatory Services

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

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

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

August 28, 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)

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

Pursuant to Commission Order G-177-14, FEI was to file a proposed rate methodology for the BERC on or before June 30, 2015. On June 25, 2015, the Commission issued Letter L-26-15 approving FEI's request for an extension of the filing date to Friday, August 28, 2015.

As such, attached please find the above noted Application by FEI.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed by: Michelle Carman

For: Diane Roy

Attachments

cc: (email only): Registered Parties to the 2012 Biomethane Application

FORTISBC ENERGY INC

Application for Approval of Biomethane Energy Recovery Charge Rate Methodology

August 28, 2015

Table of Contents

List of Appendices

List of Tables

List of Figures

1. INTRODUCTION AND APPROVALS SOUGHT

1.1 *INTRODUCTION*

FortisBC Energy Inc. (FEI or the Company), pursuant to sections 59-61 of the Utilities Commission Act, seeks approval from the British Columbia Utilities Commission (BCUC or the Commission) for a change to the Biomethane Energy Recovery Charge (BERC rate) per gigajoule rate, the rate at which biomethane is sold to voluntary participating customers. Specifically, FEI is proposing a change to the methodology used in the determination of the BERC rate, the creation of two Renewable Nature Gas (RNG) service offerings with a BERC rate applicable to each group, as well as specific guidelines for the transfer of unsold inventory and a transfer of other unrecovered costs on an annual basis.

The BERC rate has reached a point that the premium of RNG[1] over natural gas is discouraging customer participation in the RNG Program. In April of 2014, the BERC rate increased to $14.065 per Gigajoule (GJ), from $11.696 per GJ. The corresponding premium above natural gas increased to $8.11 per GJ[2]. Since then, FEI has observed a decline in the net RNG Program participation. The number of customers voluntarily opting into the RNG Program has decreased while at the same time there is an increase in the number of customers opting out of the RNG Program. FEI has also found it increasingly difficult to engage in meaningful discussions with customers interested in large volume purchases (such as University of British Columbia) at the current BERC rate.

While marketing efforts help to increase enrollment in the RNG Program, beginning in 2014 FEI decreased the level of RNG marketing to reduce RNG Program overhead costs to limit further increases to the BERC rate. At that time, the BERC rate had increased to a level that was discouraging enrollment.

FEI expects that if the RNG Program and the current BERC rate methodology were to continue as is, there will be two significant related impacts:

- First, the BERC rate will continue at a level that discourages voluntary participation in the RNG Program; and
- Second, FEI anticipates that the amount of supply on hand and the balance in the Biomethane Variance Account (BVA) will increase due to reduced demand. This would necessitate a future transfer of unsold RNG at the prevailing Commodity Cost Recovery Charge (Commodity rate or CCRA rate), which will impact non-RNG customers[3], all else being equal.

[1] Historically, RNG was also referred to as biomethane and the RNG Program as the Biomethane Program.
[2] Price of RNG less the CCRA rate + Carbon Tax. $14.065 – ($4.464 + $1.4898) = $8.111.
[3] Delivery rate impacts based on sales and transportation non-bypass customers, which also include voluntary RNG Program participants.

Thus, with this Application, FEI proposes that the BERC rate be set based on a premium above the Commission approved CCRA rate. Although this methodology may result in a BERC rate that is below the cost of RNG on a per GJ basis, FEI expects that this approach will result in maximizing the volumes sold under the RNG Program while minimizing the impact of unsold RNG on FEI customers.

Specifically, FEI is proposing to change from a single rate to two BERC rates that reflect two distinct RNG service offerings:

1. Short Term Contract: this service is for customers in residential, commercial and industrial rate classes that have, or wish to have, the flexibility to adjust their participation in the RNG Program (i.e. term, volume, blend, etc.) on a monthly basis. FEI proposes that the BERC rate for Short Term Contract customers be equal to the Commission approved January 1st CCRA rate charged per GJ, plus the current British Columbia Carbon Tax applicable to natural gas customers (Carbon Tax), plus a premium of $7.00 per GJ; and,
2. Long Term Contract: this service is for larger commercial and industrial customers who wish to be able to lock in their RNG service for a fixed length term. This offering has a minimum term of 10 years and a fixed volume commitment of 500 GJs per month. FEI proposes that the BERC rate for the Long Term Contract customer be set at a $1.00 per GJ discount to the Short Term Contract BERC rate (as described above) that is in place at the time the Long Term Contract is entered into.[4]

Consistent with the 2013 Biomethane Decision, FEI is proposing to begin the transfer of unsold biomethane older than 18 months each year or greater than 250,000 GJs out of the BVA to the Midstream Cost Reconciliation Account (MCRA). Further, FEI is also proposing an annual amortization of other unrecovered RNG Program costs through the delivery rates of non-bypass customers.

The proposed change in BERC methodology to a market–based rate, the creation of distinct service offerings and the transfer mechanisms will provide a more cost-effective means for voluntary customers to participate and are expected to result in increased participation in the RNG Program. At the same time, the expected increase in RNG Program participation at the proposed rate will result in recovery of more costs associated with RNG and therefore reduce potential future impacts of unsold RNG on natural gas rates.

FEI estimates that the rate impact to non-RNG customers of the proposed approach is approximately $9 million recovered through Storage and Transportation rates over the next five years, or an average of $0.015 per GJ, and approximately $14 million recovered through delivery rates over the next five years, or an average of $0.016 per GJ. For a Mainland Residential customer consuming approximately 90 GJs per year, these two impacts equate to

[4] FEI is not proposing that Long Term Contract rates fluctuate per customer on an annual basis, rather that once a contract is entered into, the Long Term Contract rate in the year of commencement is the rate that applies throughout the life of the contract (subject to contract escalation if applicable).

an annual bill impact of less than $3 per year (approximately $15 over five years). This proposal compares to a forecast accumulated balance in the BVA of $43 million in 2020 if the status quo is maintained, which could be left for recovery from all customers in the event the Program continues to see a decline in voluntary participation. Although it is unlikely that such a large balance would be recovered over a single year, this balance equates to an estimated delivery rate impact of $0.245 per GJ or an approximate annual bill impact of $22.[5]

In this Application, FEI will also describe its plan to resume its marketing efforts to increase the customers' awareness of the RNG Program to increase participation and minimize potential RNG impacts to non-RNG customers.

1.2 *APPROVALS SOUGHT*

FEI is seeking the following approvals:

1. Approval of a Short Term Contract BERC rate at the Commission approved January 1st CCRA rate per GJ, plus the current Carbon Tax applicable to natural gas customers, plus a premium of $7.00 per GJ, applicable to all affected biomethane rate schedules within the Mainland, Vancouver Island and Whistler Service Areas, to be effective the later of the start of the first quarter after the Commission's Decision in this Application or January 1, 2016 as discussed in Section 7 of the Application.
2. Approval that the Long Term Contract BERC rate be set at a $1.00 per GJ discount to the Short Term Contract rate;
3. Approval to discontinue the quarterly BERC and BVA report and replace it with a single annual report in conjunction with the Fourth Quarter CCRA & MCRA report;
4. FEI may apply to transfer unsold biomethane supply that is greater than 18 months in age and/or 250,000 GJs in the BVA to the MCRA at the prevailing CCRA rate on January 1 each year; and,
5. Approval to amortize the forecast December 31 balance in the BVA, net of the transfer of unsold inventory and remaining supply costs, through the delivery rates of all non-bypass customers effective January 1 of the subsequent year.

A draft form of order sought is included in Appendix F.

1.3 *REGULATORY PROCESS*

FEI is proposing a written regulatory process for review of this Application. This Application does not represent a change in the nature of the RNG Program that has been recently reviewed by the Commission or the supply of renewable natural gas; rather, it proposes some changes that affect the rates for the RNG Program and the regulatory accounting mechanisms aligned

[5] Storage and Transportation rate impacts based on non-bypass sales customers and Delivery rate impacts based on sales and transportation non-bypass customers.

with the changes. Moreover, the changes to lowering BERC rates to encourage RNG Program participation, which is the intent of this Application, was contemplated in the previous Commission Decision as discussed in Section 2 below. As such, FEI believes that a single round of information requests from the Commission and Interveners followed by written submissions provides for an appropriate and efficient review for this Application.

Due to the scope of this application, FEI proposes that the process be conducted in a timeframe that will allow for the implementation of the new rate structures for January 1, 2016.

Table 1-2: Proposed Regulatory Timetable

ACTION	DATE (2015)
Intervener Registration	Thursday, September 10
Commission Information Request No. 1	Thursday, September 24
Intervener Information Request No. 1	Thursday, October 1
FEI Response to Information Requests	Friday, October 16
FEI Final Submission	Wednesday, October 28
Intervener Final Comments	Friday, November 6
FEI Reply Submission	Friday, November 13

1.4 *ORGANIZATION OF THE APPLICATION*

The remainder of this Application is organized as follows:

- Section 2 – RNG Program Regulatory History
- Section 3 – Program Structure
- Section 4 – Current Challenges
- Section 5 – Research on Current RNG Premium
- Section 6 – Alternatives Considered
- Section 7 – Proposal
- Section 8 – Potential Impact on Non-RNG Customers
- Section 9 – Accounting Treatment and Rate Setting
- Section 10 – Conclusion and Continued Oversight of the RNG Program

2. RNG PROGRAM REGULATORY HISTORY

This section provides a brief summary of the regulatory history leading to the establishment of the RNG Program and key guidance from the Commission relevant to this Application.

On June 8, 2010, FEI (then Terasen Gas Inc.) filed an application for the approval of a Biomethane Service Offering (the 2010 Biomethane Application) and supporting business model, including the approval of two supply projects. On December 14, 2010, the Commission issued its Biomethane Decision, authorizing FEI to move forward with a Biomethane Program (now referred to as RNG Program) for a two-year “pilot” period and approving the two supply agreements. In addition, this Biomethane Decision generally (but not exhaustively) approved:

- Rate schedules to allow FEI to sell RNG;
- Cost allocations, deferral accounts, and accounting treatment for the costs associated with the RNG Program;
- An expedited process for approval of future RNG supply contracts; and
- A RNG supply cap set at a maximum annual purchase of 250,000 GJ at a maximum price of $15.28 per GJ.

Following that Decision and pursuant to Order No. G-194-10, FEI reported on the RNG Program in the following:

- FortisBC Energy Utilities 2012-2013 Revenue Requirements and Rates Application (2012-2013 RRA); and
- Quarterly Gas Costs Reports.

In 2012, the RNG Program was also evaluated in the AES inquiry, where additional principles were established and used to guide the Commission in subsequent decisions.

On December 19, 2012, FEI filed an application entitled Biomethane Service Offering: Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis (the 2012 Biomethane Application). On December 11, 2013, the Commission issued Order No. G-210-13 and accompanying Decision (the 2013 Biomethane Decision). The 2013 Biomethane Decision determined that the “continuance of the Biomethane Program on a permanent basis is approved with certain modifications as described in the Decision.[6]” The modifications to the RNG Program included:

- A new annual RNG supply cap of 1,500,000 GJ (PJ); and
- Modification of the cost allocation, such that costs included in the BVA for recovery from RNG customers included RNG Program marketing and administration costs and

[6] Page 3 of Order G-210-13

interconnection costs from future supply projects that had not been identified prior to the 2013 Biomethane Decision.

In Section 4 of the 2013 Biomethane Decision, the Commission provided general guidance on cost recovery and the establishment of a deferral account to capture cost associated with the sale or transfer of biomethane at a price below its fully allocated cost. The Commission approved the establishment of an account to capture unrecovered costs associated with the transfer of biomethane into an Unrecovered Biomethane Premium Deferral Account (UBPDA) at the prevailing CCRA rate:

> *"To facilitate this recovery, the Panel approves the establishment of an "Unsold Biomethane Premium" deferral account (UBPDA) to which, in this example, $100,000 would be transferred. FEI is directed to recover any balance in the Unsold Biomethane Premium deferral account from all FEI non-bypass customers, through a rate rider, on a timely basis."* [7]

Further, the Commission directed that the unrecovered costs be recovered from as broad a base of FEI's customers as possible.

> *"Accordingly, Panel directs that if, as and when volumes of unsold and unsalable biomethane are moved to the MCRA, the dollar balance transferred be calculated using the prevailing Commodity Cost Recovery Charge at the time of the transfer. The difference between the commodity value of the balance to be transferred to the MCRA and the selling price of that balance at the BERC must be recovered from as broad a base of FEI's customers as possible.* [8]

The Commission recognized that the price of biomethane may at some point in the future be high enough to discourage participation in the RNG Program. In these circumstances, the Commission's guidance was that it may be appropriate to set the BERC rate below the cost, thereby maximizing the volumes sold while minimizing the unsold cost impact the remainder of FEI ratepayers. The Commission stated:

> *"In this circumstance, the Panel is of the view that it may be appropriate to set the BERC at a lower rate, and recover the difference between the BERC and the fully allocated costs of acquiring the biomethane through the Biomethane Premium deferral account previously discussed. This strategy may enable FEI to maximize the revenues from the Biomethane Program."* [9]

If this occurs, FEI was directed to make an application to the Commission for approval of a lower BERC rate, as follows:

---

[7] 2013 Biomethane Decision, p. 69.
[8] 2013 Biomethane Decision, p. 69.
[9] 2013 Biomethane Decision, p. 72.

"Therefore, in the event FEI considers it necessary to set a lower BERC rate than would be set using the BERC rate setting methodology which includes all costs FEI is directed to include in this Decision, FEI is directed to bring before the Commission an application for approval of the lower BERC rate. The application should provide an analysis of the full circumstances, and sufficient evidence to support that analysis." [10]

In response to the decline in program participation experienced since April 1, 2014 and in light of the guidance and direction provided in the 2013 Biomethane Decision, this Application is being filed for approval of a change in the BERC rate methodology and a mechanism for the transfer of unsold quantities of biomethane to the MCRA as contemplated in the 2013 Biomethane Decision.

[10] 2013 Biomethane Decision, p. 72.

3. PROGRAM STRUCTURE

With the voluntary RNG Program, FEI seeks to encourage and make available the production of RNG in British Columbia (BC) and to provide a lower GHG offering for customers who wish to directly purchase RNG to meet their own GHG requirements. The current RNG Program provides benefits to all British Columbians in the form of reduced GHG emissions and the stimulation of a locally sourced supply of gas that otherwise would be considered a waste product. The customers participating in the Program pay a premium for the Program.

FEI is not proposing a change to the nature of the RNG Program as determined in the 2013 Biomethane Decision. Rather, the Application is proposing amendments to the BERC rates and associated regulatory accounting mechanisms. FEI is providing the following background and current status to help provide context for the Application. Specifically, the program costs, biomethane production and purchase, customer sales and the existing BERC rate methodology are described further in this section.

3.1 *RNG PROGRAM COST AND RATE SUMMARY*

Currently, and as approved by the Commission, all costs associated with the RNG Program are allocated to the BVA and used in the determination of the BERC rate.

As outlined in the 2013 Biomethane Decision, the following table summarizes the costs and recoveries that are currently, and will continue to be, captured in the BVA:

Table 3-1: RNG Program Costs and the BVA[11]

Biomethane Variance Account (BVA)	Recovery From
• Cost of procuring biogas	Biomethane Customer
• Cost of upgrading	Biomethane Customer
• Interconnection costs including the pipe	Biomethane Customer shared with Supplier based on Interconnection Test
• Biomethane Program Overhead Costs	Biomethane Customer
LESS	
• REVENUES collected through BERC rates	Biomethane Customer

3.1.1 BERC Rate and BVA Balances

The BERC rate is the rate that the customers who participate in the RNG Program pay for their RNG. It is a commodity charge like the CCRA rate charged for natural gas. The BERC rate is charged for equivalent amounts of RNG consumed regardless of biomethane Rate Schedule, blend or rate class, and is reflected on a customer's bill if applicable. All other aspects of the customer bill remain the same. Currently, all RNG-related costs (with the exception of some

[11] 2013 Biomethane Decision, p. 70.

interconnections)[12] are included in the BVA and are recovered from RNG customers at the BERC rate. These costs generally include gas costs, capital and operating costs for FEI-owned equipment for the production of RNG and program administration costs, offset by revenues collected through BERC rates.

Currently, the BERC rate is reviewed on a quarterly basis. The BERC rate is calculated on the forecast balance in the BVA account (i.e. as at the day before the start of the quarter that is being reviewed) and a twelve-month forward forecast of costs comprised of the cost of supply, the cost of service of upgrader and interconnection capital investments, program administration, program education and program marketing. To determine the BERC rate, the summation of the forecast BVA balance and forecast costs is divided by the forecast quantity of supply produced for the same twelve-month period.

By Order G-177-14, 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). These guidelines are comprised of the following:

I. Annual resetting of the BERC rate 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.

Table 3-2 below provides a continuity of the costs and quantity assumptions embedded in the BERC rate since October 1, 2010. The increase in overhead costs effective April 1, 2014 is due to the inclusion of education and marketing costs in accordance with the 2013 Biomethane Decision.

[12] BCUC Letter L-10-14 Response to Request for Clarification.

Table 3-2: Calculation of the BERC Rate, $ Thousands[13]

	October 1, 2010[14]	January 1, 2012	April 1, 2014	January 1, 2015	October 1, 2015[15]
Forecast BVA Balance (Pre-Tax)	$0	$606.4	$1,245.6	$1,485.1	$1,766.3
Cost of Supply	-	-	1,309.7	2,204.9	2,926.6
Interconnect and Upgrader[16]	-	-	279.8	754.4	761.2
Program Overhead[17]	-	-	243.7	306	227.4
Total Costs[18]	1,764.2	1,523.5	1,833.2	3,265.3	3,915.2
Total Costs to be Recovered *(BVA Balance + Total Costs)*	1,764.2	2,129.9	3,078.8	4,750.4	5,681.5
Supply Quantity (TJ)	178.1	182.1	218.9	329.6	377.8
Approved BERC Rate ($/GJ)	$9.904	$11.696	$14.065	$14,414	$14.414

As noted above, the BERC rate is calculated based on the quantity of supply available. Thus, any difference in the quantity available and customer demand for RNG will result in an impact to the BVA. Table 3-3 below provides a continuity of the BVA balance at year-end, commencing in 2010.

Table 3-3: BVA Balance (Pre-Tax), as at December 31, $ Thousands[19]

	2010	2011	2012	2013	2014
Opening Balance[20]	$0	$59.6	$463.1	$948.8	$1,300.4
Adjustment to Restate Pre-tax Balance[21]	-	(1.6)	(9.3)	9.6	-
BVA Costs Incurred	59.6	451.8	767.7	1,217.4	2,187.9
BVA Costs Recovered	0	(46.7)	(272.7)	(875.4)	(1,644.7)
Closing Balance[20]	$59.6	$463.1	$948.8	$1,300.4	$1,843.6

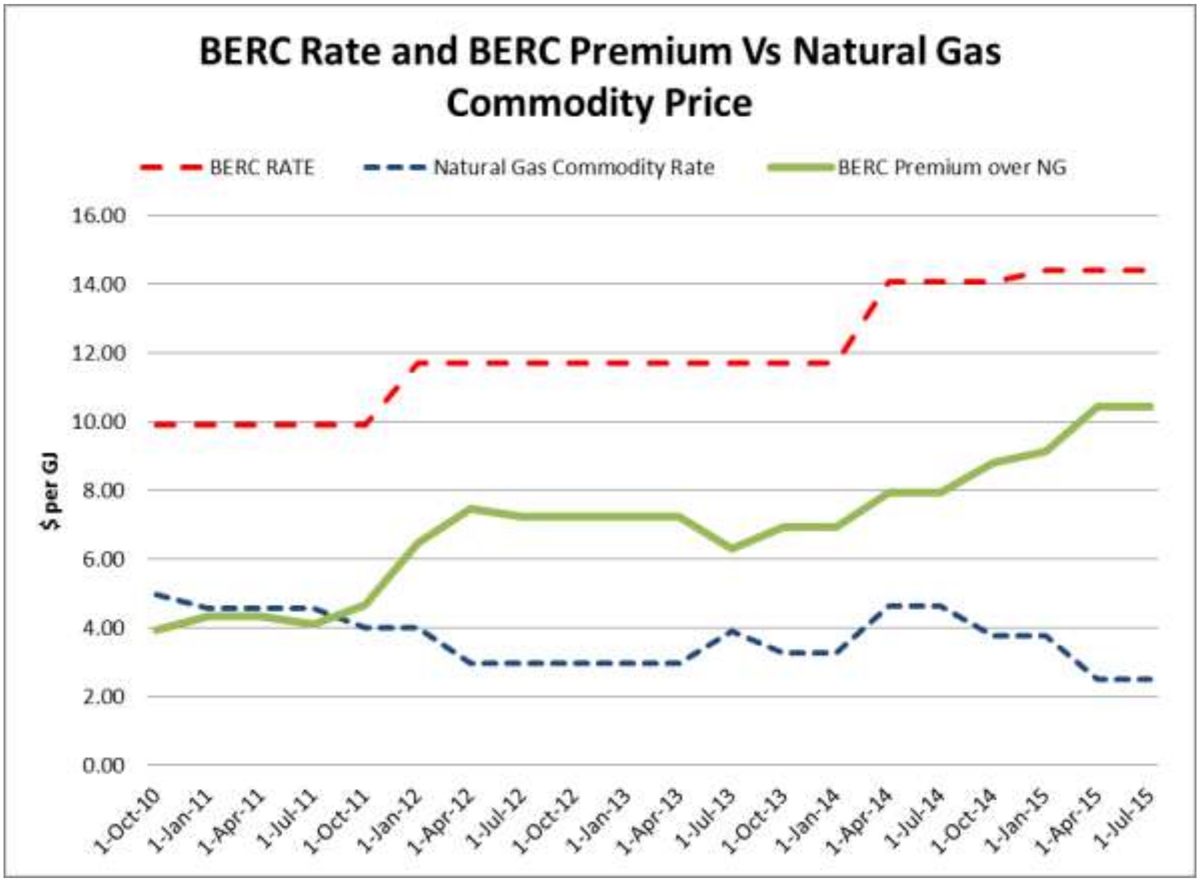
3.1.2 History of RNG Premium

This section shows the history of the BERC rate since the inception of the RNG Program. The chart below shows the historical natural gas rate (CCRA rate), the BERC rate and the relative premium of biomethane compared to natural gas. The premium is calculated by taking the

13 As filed in the FEI Quarterly BVA Reports.
14 As filed in the 2010 Biomethane Application.
15 As proposed in the FEI 2015 Third Quarter BVA Report filed with the Commission on August 14, 2015.
16 Includes both capital and operating costs.
17 Includes Program administration, education and marketing costs.
18 Forecast Costs Incurred for the following 12-Month Period.
19 Actual BVA balance at year end and as filed in the BVA Annual Reports. This balance may be different than the forecast balance shown in Table 3-2 used in the determination of the BERC Rate.
20 Before Adjustment for Unsold Biomethane.
21 Adjustment to account for the change in the annual tax rate.

difference between the quarterly BERC rate and the Commission approved CCRA rate (natural gas commodity rate) plus Carbon Tax[22].

Figure 3-1: BERC Rate, BERC Premium and Natural Gas Commodity Rate



3.2 *RNG PRODUCTION AND PURCHASE*

This section describes the current supply side of the RNG Program. The supply ownership model was extensively described in the original 2010 Biomethane Application and further clarified in the 2012 Biomethane Application. For convenience, the model will be summarized here.

3.2.1 RNG Production

Each supply project consists of three major components that work together to produce raw biogas, purify the raw biogas to become RNG and confirm that the RNG meets strict pipeline quality standards. These components consist of the following:

[22] Because Biomethane receives a credit equal to the Carbon Tax, the BERC rate is effectively lower by the amount of the Carbon Tax. Therefore, the premium that customers see is equal to BERC – [CCRA rate + Carbon Tax].

- Assets required to digest organic material to create raw biogas and collect raw biogas also known as the biogas source (which can include a landfill and associated collection system);
- Assets required to upgrade the raw biogas to biomethane (upgrader); and
- Interconnection facilities, including metering, monitoring and piping.

FEI may invest in upgrading plants and interconnection facilities when the supplier is a regional or municipal government. In all other cases, FEI may only invest in the interconnection facilities and not invest in the upgrading plant. For all future projects, the capital investment and operating costs incurred by FEI will be captured in the BVA[23].

FEI is limited to a maximum investment in interconnect facilities and the pipeline required to connect to the existing FEI natural gas system. The maximum investment is determined by the Biomethane Interconnect Test as approved by Order G-159-14 and is summarized as follows:

1. FEI may invest a maximum of $560,000 in the interconnect facility; and
2. FEI may invest no more than $0.30 per GJ in the interconnecting pipe (where the value of investment in the pipe is determined by dividing the estimated cost by the 20-year total contracted RNG supply volume).

In the event that the interconnect facility does not pass the test, the supplier must pay a contribution in aid of construction.

3.2.2 RNG Purchase

FEI enters into long-term contracts with suppliers for either raw biogas or RNG. In the case of raw gas, it is purified so that it is interchangeable with natural gas and in the case of RNG, it is already interchangeable with natural gas. Once injected into the FEI natural gas system, the RNG is notionally banked and sold to customers as RNG (or biomethane).

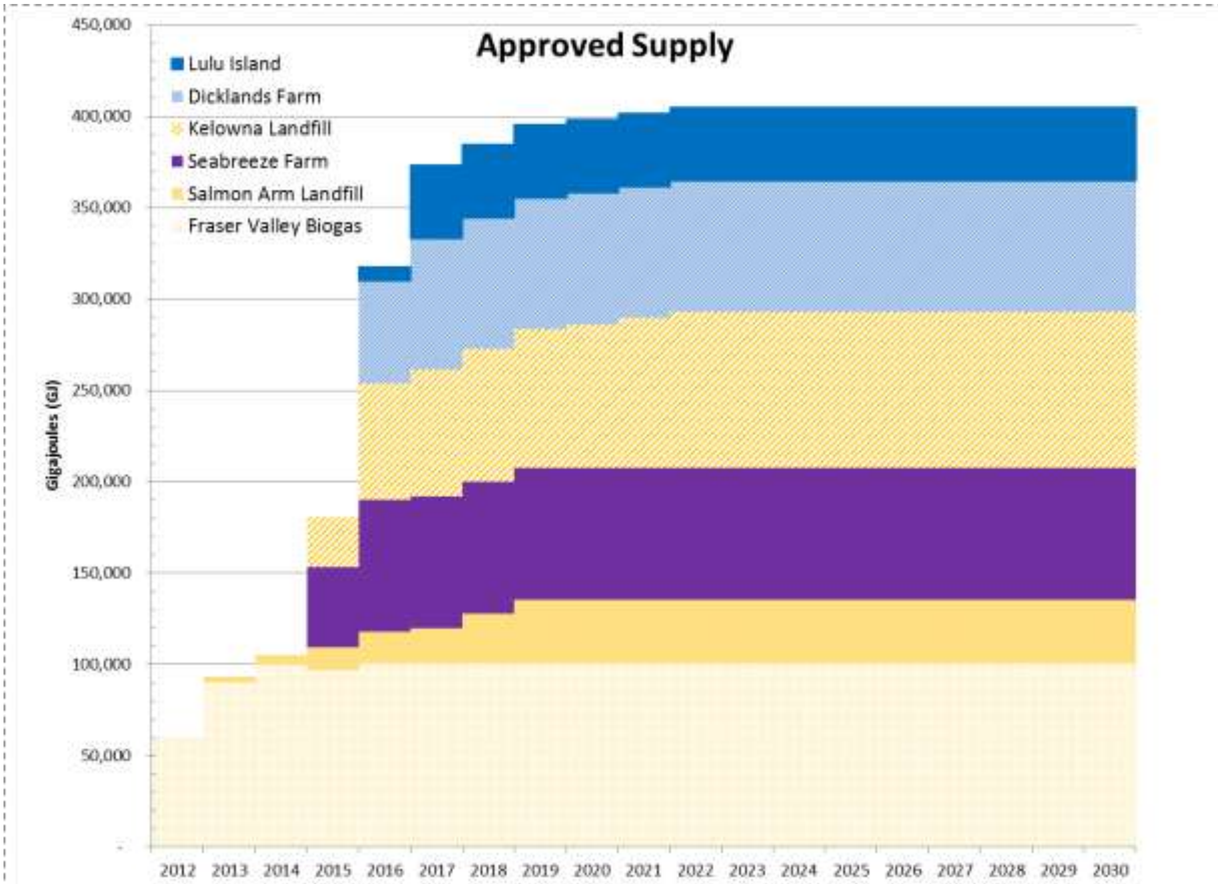
FEI is required to establish future contracts according to the criteria established in Order No. G-194-10 in order to meet filing requirements in sections 71(1)(a) and 71(1)(b) of the Utilities Commission Act.

[23] For the first six supply contracts, FEI will recover costs associated with the Interconnect facilities from all customers. Refer to BCUC Letter L-10-14 for clarification.

3.2.3 RNG Supply Projection

Currently, FEI has established six RNG supply contracts[24]. The total supply of RNG from these projects will total approximately 430,000 GJ annually once they are all operating at full capacity as shown in Figure 3-2 below.

Figure 3-2: Established RNG Supply Contracts, GJ



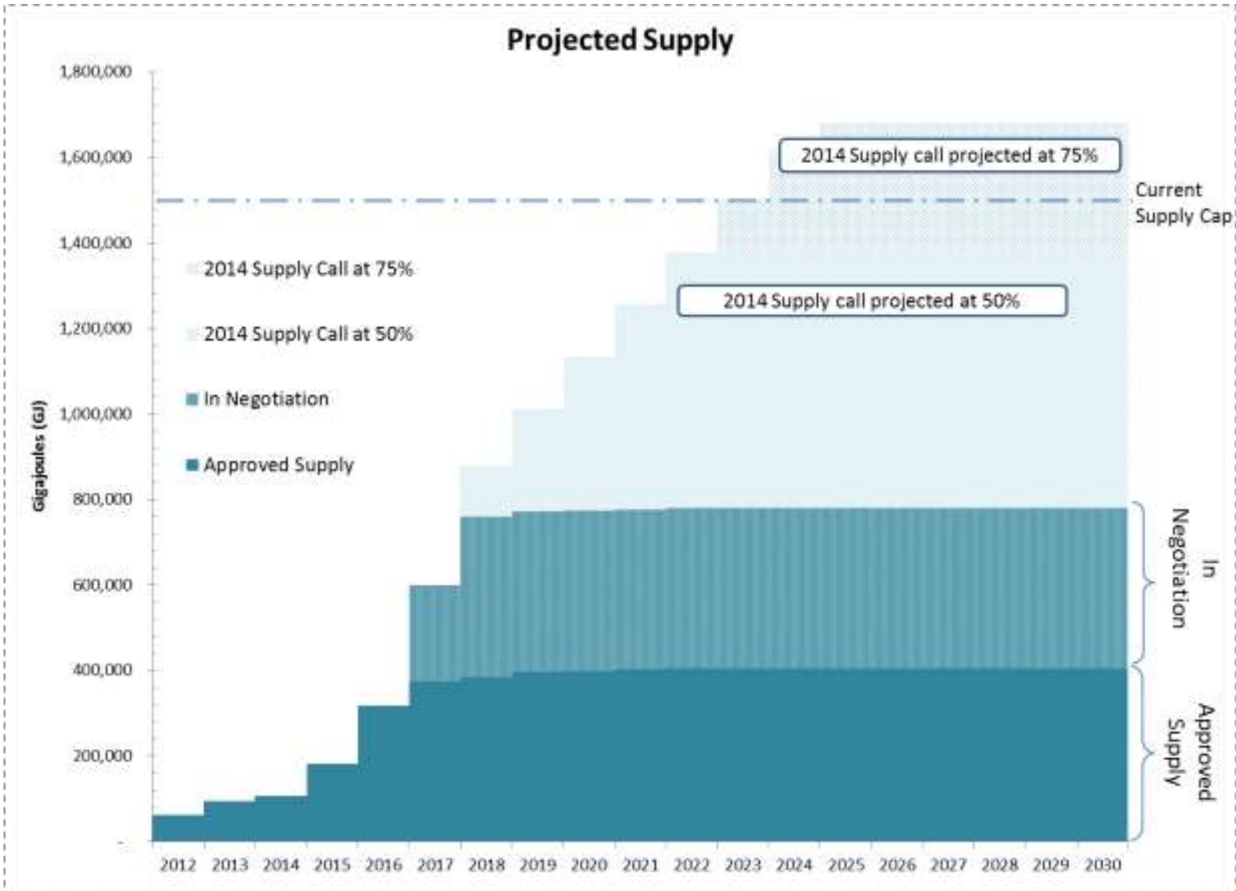
FEI expects that RNG supply will continue to grow over time. Figure 3-3 below shows the projected supply for the next 15 years of the RNG Program including the existing approved supply (noted as approved supply). Most notably, FEI expects to add both the Vancouver Landfill and the Surrey Biofuel facility supply to the pool over the next 2-3 calendar years. Beyond that, FEI projects that supply projects will be added in order to reach the maximum yearly supply limit of 1.5 PJ. The future growth of supply beyond the Vancouver Landfill and Biofuel facility is based upon the potential supply in BC identified by a Request for Expression of Interest[25] (RFEOI) issued by FEI in the spring of 2014. That RFEOI identified approximately 1.2

[24] There were seven supply contracts approved in total: two with the original application, followed by the City of Kelowna landfill and four others as per Order G-79-13. Order G-79-13 included the approval of the Earth Renu supply contract, which has since been terminated due to the business failure of Earth Renu.

[25] Compliance filing from BCUC Order G-210-13 filed on June 11, 2014.

PJ of supply. FEI has therefore estimated the projected growth in supply beyond 2017 using the potential supply identified in the RFEOI. The total potential supply indicated in the graph below is based upon a scenario where FEI develops approximately 50% of the total supply available from the RFEOI and another scenario where 75% of the supply is developed. The 50% scenario is enough to reach approximately 1.4 PJ of total supply by approximately 2023.

Figure 3-3: Forecast RNG Supply, GJ



3.2.4 Supply Limits

Currently, RNG supply is limited to a maximum yearly volume of 1.5 PJ and a maximum price of $15.28 per GJ (per order G-210-13). This limit on both volume and price serves to provide a bound on the maximum potential impact to non-RNG customers in the event that FEI transfers unsold biomethane into the MCRA. That is, the rate impact to non-RNG customers is limited to the maximum difference in the calculated BERC rate and the CCRA rate multiplied by the maximum volume.

3.3 *BIOMETHANE CUSTOMER SALES*

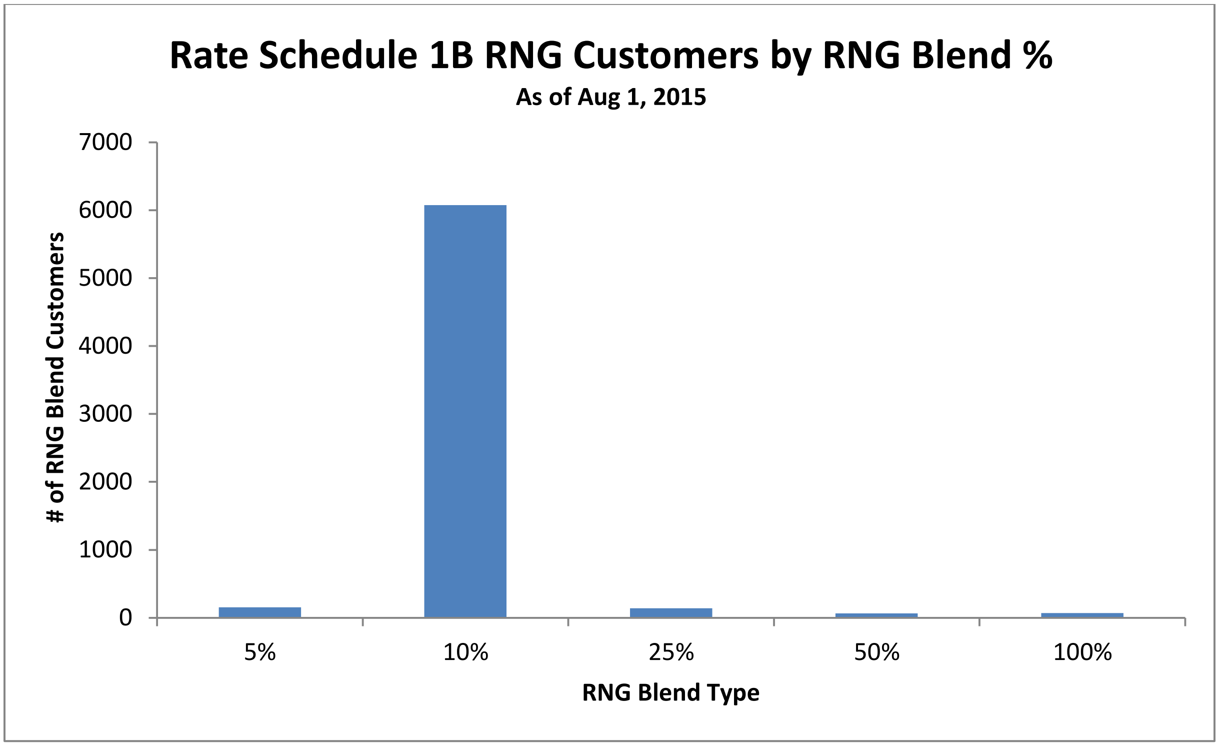
FEI currently has rates in place to serve virtually all of its Lower Mainland, Inland, Columbia, Vancouver Island and Whistler customers. Customers may choose a designated percentage of their consumption as RNG or a fixed monthly amount of RNG in the case of transportation customers.

For example, an average residential customer today who consumes 90 GJ of gas annually may designate 10% of his or her use as RNG and pay the associated premium. In this case, the customer will buy 9 GJ of RNG at the current biomethane price of $14.414 per GJ and 81 GJ of natural gas at the price of $2.486 per GJ. This customer will also receive a Carbon Tax credit equal to $1.498 per GJ on the biomethane. Due to the higher commodity rate for RNG, the total yearly premium would then be $93.94 or $7.83 per month on average.

3.3.1 Different Blends (%) of RNG

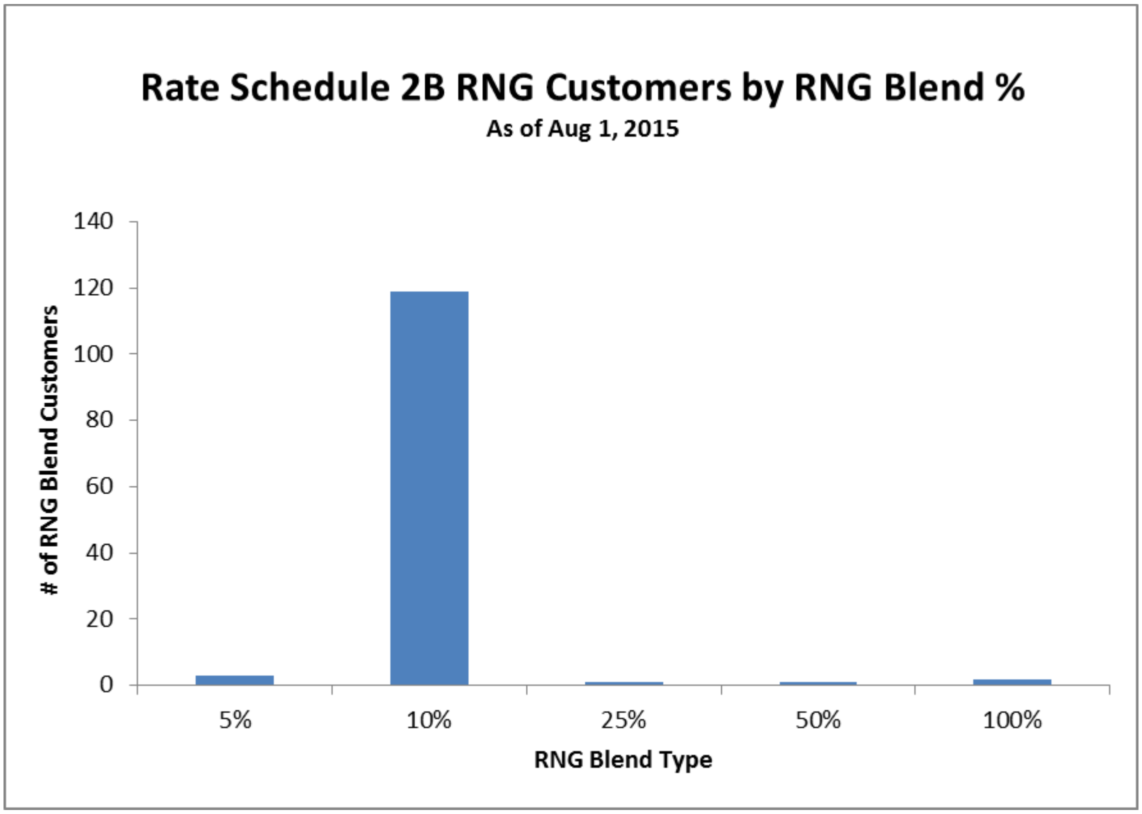
In the original RNG offering, FEI provided customers with the option to designate 10% of their consumption as RNG and the remainder as natural gas (i.e. a 10% "Blend"). Effective August 1, 2014, as approved by Commission Order G-101-14 regarding FEI's Application for Amendments to Rate Schedules 1B, 2B, and 3B Regarding Biomethane Blends Available, and for Approval of a New Biomethane Service Offering (the 2014 Application), FEI introduced the option for customers to choose different blends. Specifically, as of August 2014, customers could choose to designate 5%, 10%, 25%, 50% or 100% for the RNG portion of their consumption. The change was intended to increase market uptake of RNG by giving customers more options with respect to the level of RNG that meets their needs. Figure 3-4 shows the total RNG customer base under Rate Schedule 1B, broken out into number of customers at each blend level as of the end of July 2015.

Figure 3-4: Residential Customer by RNG Blend



FEI has also provided the number of RNG customers in each blend category for Rate Schedule 2B customers in Figure 3-5.

Figure 3-5: Small Commercial Customers by RNG Blend



At this point in time, the addition of new blends of RNG has not had a significant impact on the number of customers or the volume of RNG. As shown in Figure 3-4 and Figure 3-5, the majority of customers purchase a 10% blend of RNG, with relatively few purchasing other blends.

As approved in the 2014 Biomethane Application Decision, FEI introduced an option for customers to designate 5% of their usage as RNG. Since the introduction of this option, FEI has seen the number of customers choosing a 5% option increase steadily. On average, since August 2014, FEI has added an average of 16.5 customers per month in this category for a total of 165 customers as of July 2015. The corresponding number of customers taking advantage of higher percentage options showed an initial interest followed by a decline in the number of enrollments on a monthly basis as the BERC rate increased.

As the price of RNG has increased in both absolute terms and relative to natural gas since the beginning of 2015, the blends sign-up pattern has noticeable shifted towards the lower blend options. More specifically, between the launch of the blends in August 2014 and July 2015, there was a noticeable trend away from the higher blends towards the 5% blend option. Although during the last two months, FEI has seen a slight increase in the sign-ups for the higher percentage blends, the 5% and 10% options remain the most popular as shown in Figure 3-6 below. This leads FEI to believe that the higher BERC rate is also discouraging enrollment at 10% and higher blend options as the customers are likely to consider the total bill impact.

Additionally, FEI also believes that this trend is due to the launch of the RNG Program in the Vancouver Island and Whistler regions, and the corresponding lower incremental bill costs in those territories. Though the price for RNG is higher than in previous years, the customers on Vancouver Island and in Whistler appear to be less sensitive to the premium. This data reinforces the concept that the relative premium versus natural gas matters to customers.

Figure 3-6: Residential Enrollment by Month and by Blend

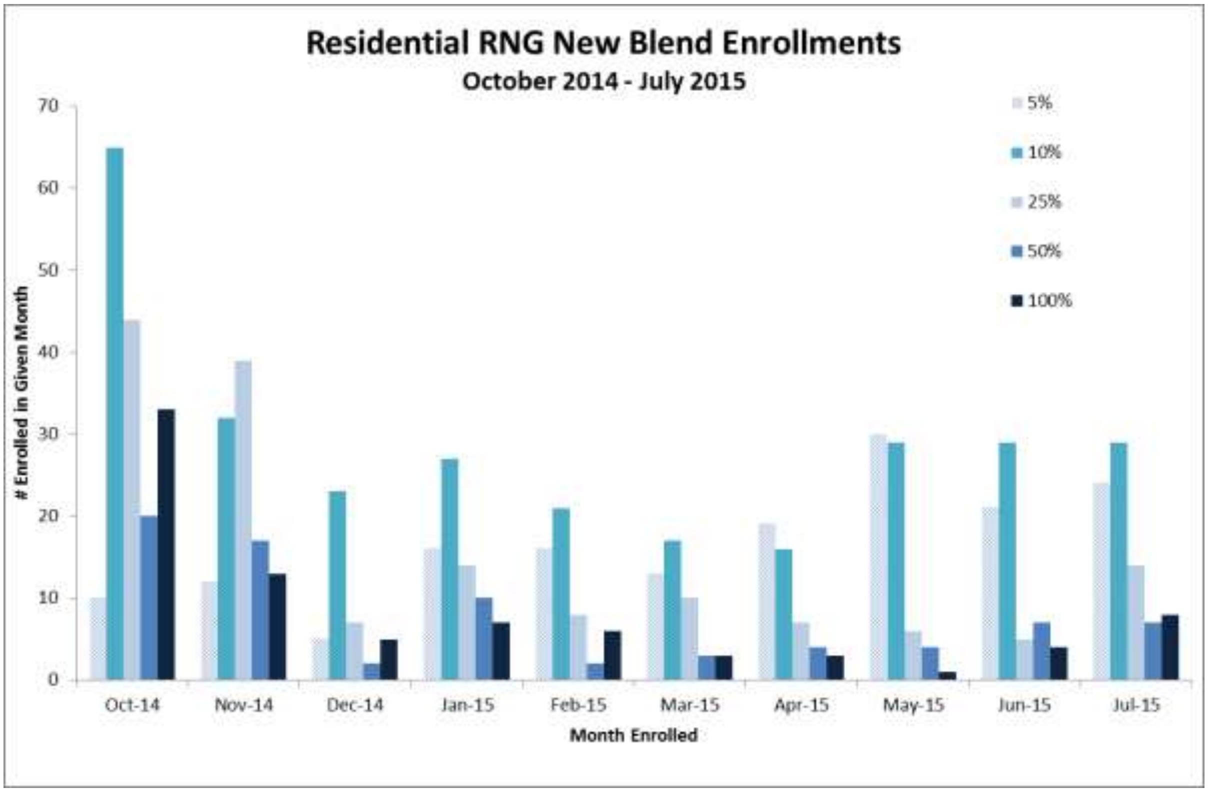
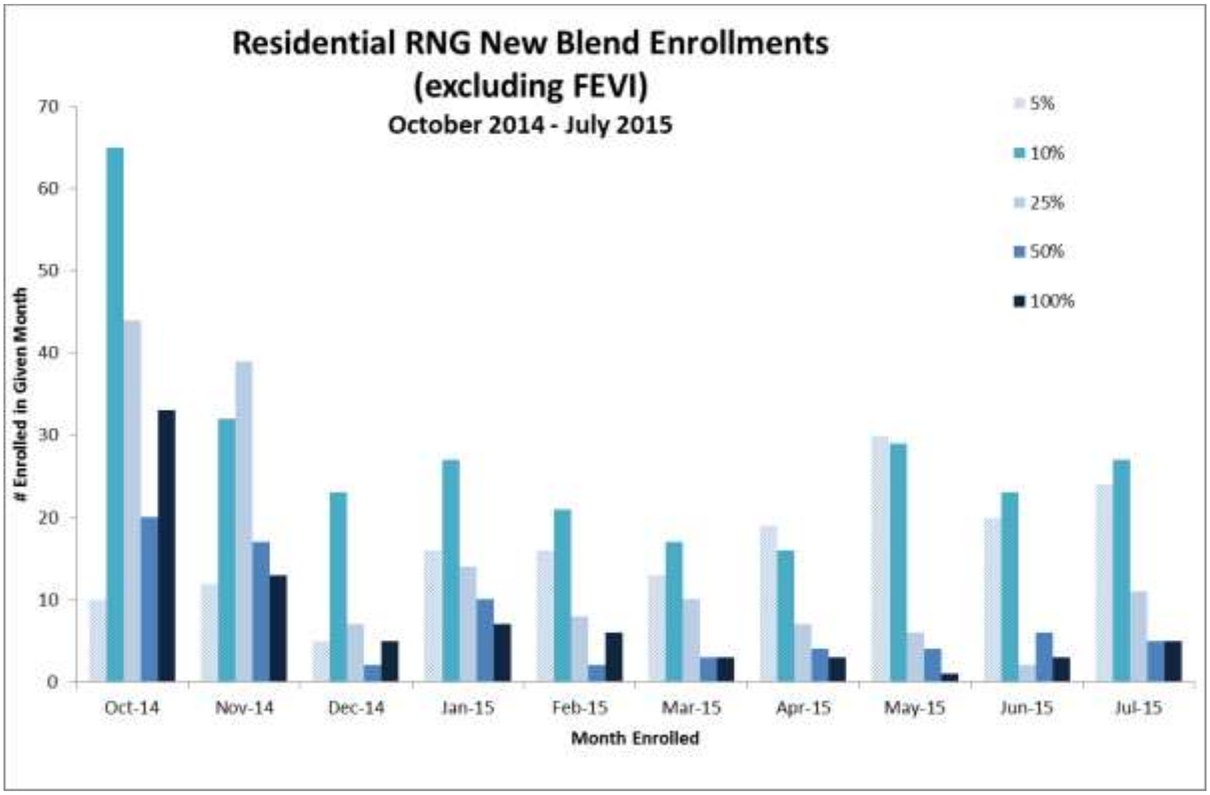


Figure 3-7: Residential Enrollment by Month and by Blend, excluding FEVI



In order to develop future demand estimates, FEI analyzed the current customer blend selections. Based on the current blend subscribers, the weighted average blend of all usage is 11%, which FEI has used in all sales volume estimates in this Application.

4. CURRENT CHALLENGES

The current challenge to the RNG Program is the large premium for RNG compared to the CCRA rate. Market prices for natural gas commodity began to drop significantly in 2009 resulting in a current approved Commodity Cost Recovery Charge of $2.486/GJ. Thus, with the Carbon Tax of $1.4898/GJ included, RNG costs $10.438/GJ more than the current natural gas commodity charge today. The price differential compared to natural gas is contributing to a decline in customer participation from the historical growth levels seen in the first two years of the RNG Program.

Concurrently, as the BERC increased, FEI scaled back its marketing efforts (thus overhead) to reduce upward pressure on the BERC rate. While marketing efforts have resulted in additional participation in the RNG Program, FEI concluded that the RNG premium had reached a level that any further upward movement of the BERC rate would be more harmful than the benefits of marketing. FEI believes that a return to higher marketing spend levels are required to increase awareness of the RNG program. However, without a change in rate setting mechanism, this spend would result in a higher BERC rate and possibly even lower enrollment.

As a result, FEI believes that a change to the BERC rate methodology is warranted to both foster future program success and to minimize the potential impact of unsold costs on non-RNG ratepayers.

To determine what changes to make to the RNG Program and specifically the BERC rate, the Company relied on its customer data, customer feedback and available market data in addition to the 2013 Biomethane Decision to help guide the proposals in this Application. The declining enrollment, expected pricing based on market evidence and further analysis are more fully described in the following sections.

4.1 *RNG CUSTOMER ADDITIONS AND ANALYSIS*

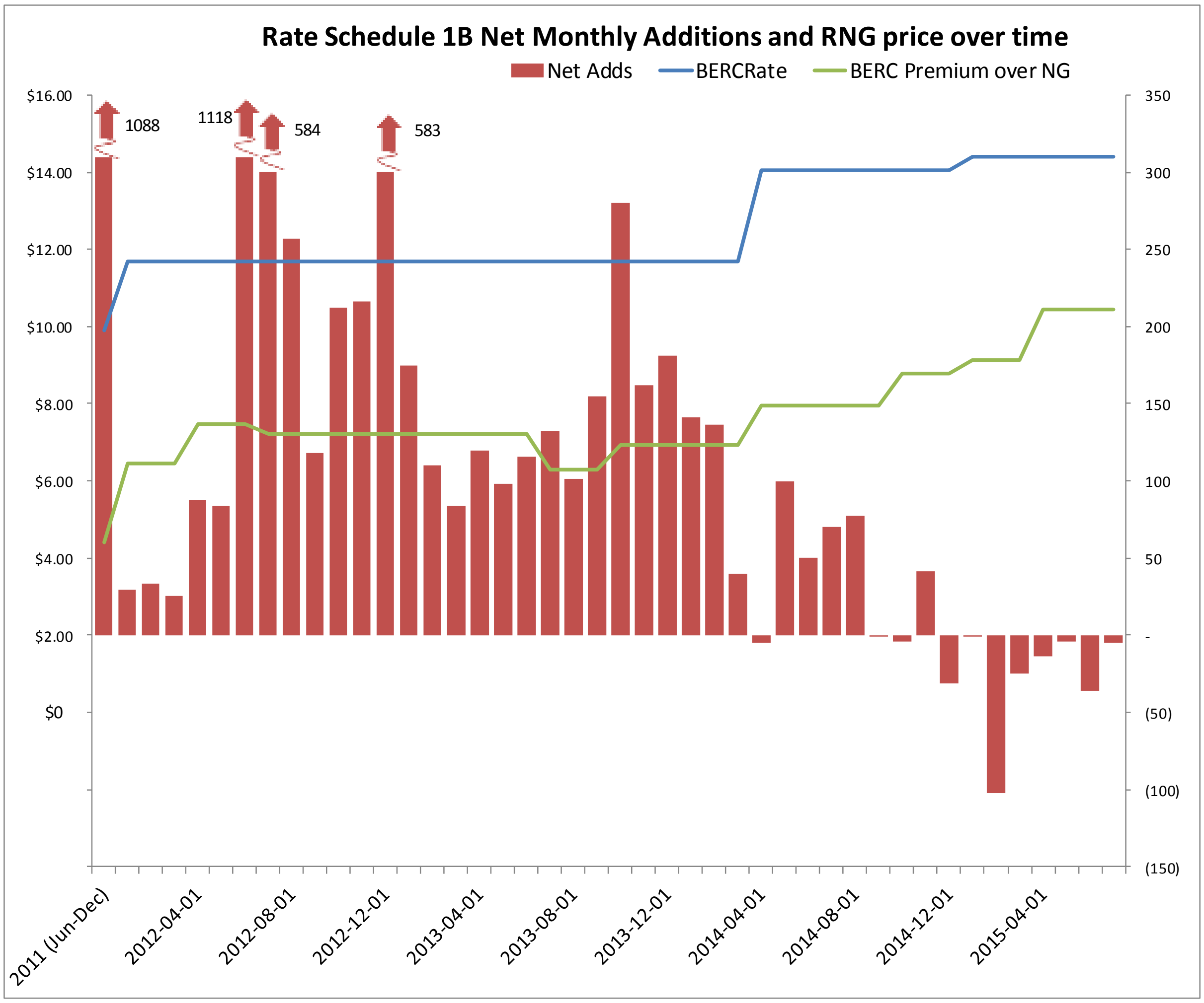
FEI has been tracking the number of RNG customer additions and drops across the different rate classes on a monthly basis since the RNG Program inception. The RNG Program experienced a persistent, upward trend in net customer additions from its launch until 2014. Over the course of 2014 and into 2015, the RNG Program has seen a decrease in the number of new customers joining the RNG Program and an increase in the number of customers leaving the RNG Program, corresponding with increases in the price of RNG over that period. For the past eight months, there has been a monthly net negative trend in customer participation, and only once in the last 11 months has it been positive.

In the following sub-sections, FEI will provide data based on customer tracking over the history of the RNG Program, which will show that there has been a shift in customer participation from a positive trend to a negative trend and that the trend corresponds to the relative cost of RNG compared to natural gas.

4.1.1 Decline in Residential Customer Enrollment (Rate 1B)

When monthly customer additions are compared to fluctuations in the BERC rate over time, a correlation can be observed. As seen in Figure 4-1 below, FEI was initially able to add customers to the RNG Program, even with an increasing BERC rate; however, the most recent increases in BERC rate have resulted in a negative trend. As shown in the graph, the recent increases in the BERC have resulted in increased customer losses, which more than offset additions and result in a net customer decrease. Net monthly enrollment compared to the BERC rate and the BERC premium are illustrated in Figure 4-1 below:

Figure 4-1: Residential Net Monthly Additions Compared to the RNG Price



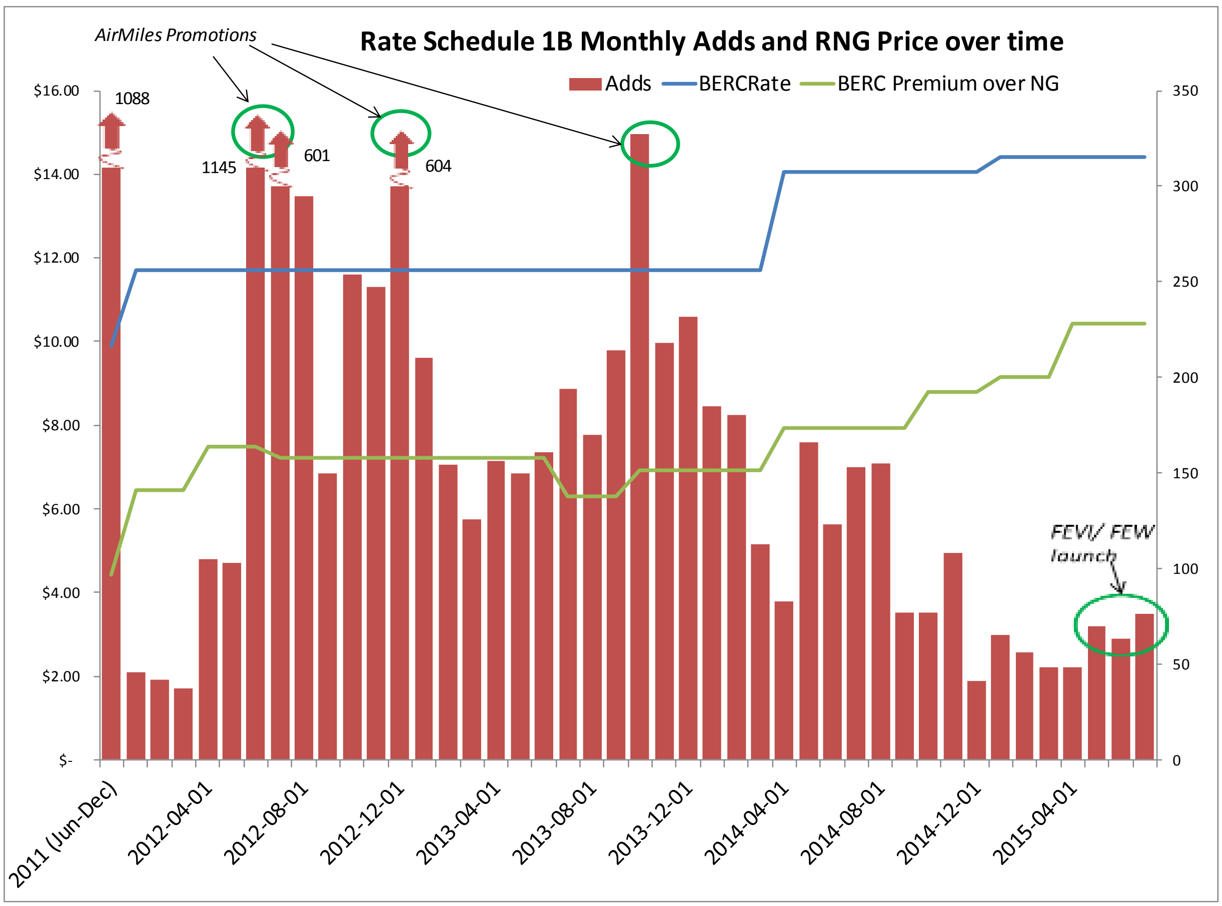
To understand the change in net additions, FEI evaluated both additions and drops. Figure 4-2 below breaks out the trends in RNG Program enrollment from June 2011 to July 2015. The figure demonstrates that there have been several monthly spikes in RNG Program enrollment up until December 2013, along with a consistent trend of strong monthly additions.

The enrollment spikes can be explained by specific historical actions. The first spike in signups in 2011 was during the launch phase when FEI was marketing more broadly, and many early adopters enrolled. Spikes two, three and four (in April 2012, December 2012 and October 2013) corresponded with the three marketing promotions conducted with Air Miles.

However, from April 2014 forward, there is a consistent decline in monthly residential additions. The lower average additions correspond to the increase in the BERC rate from $11.696 to $14.065 (an increase of $2.369) that took effect on April 1, 2014.

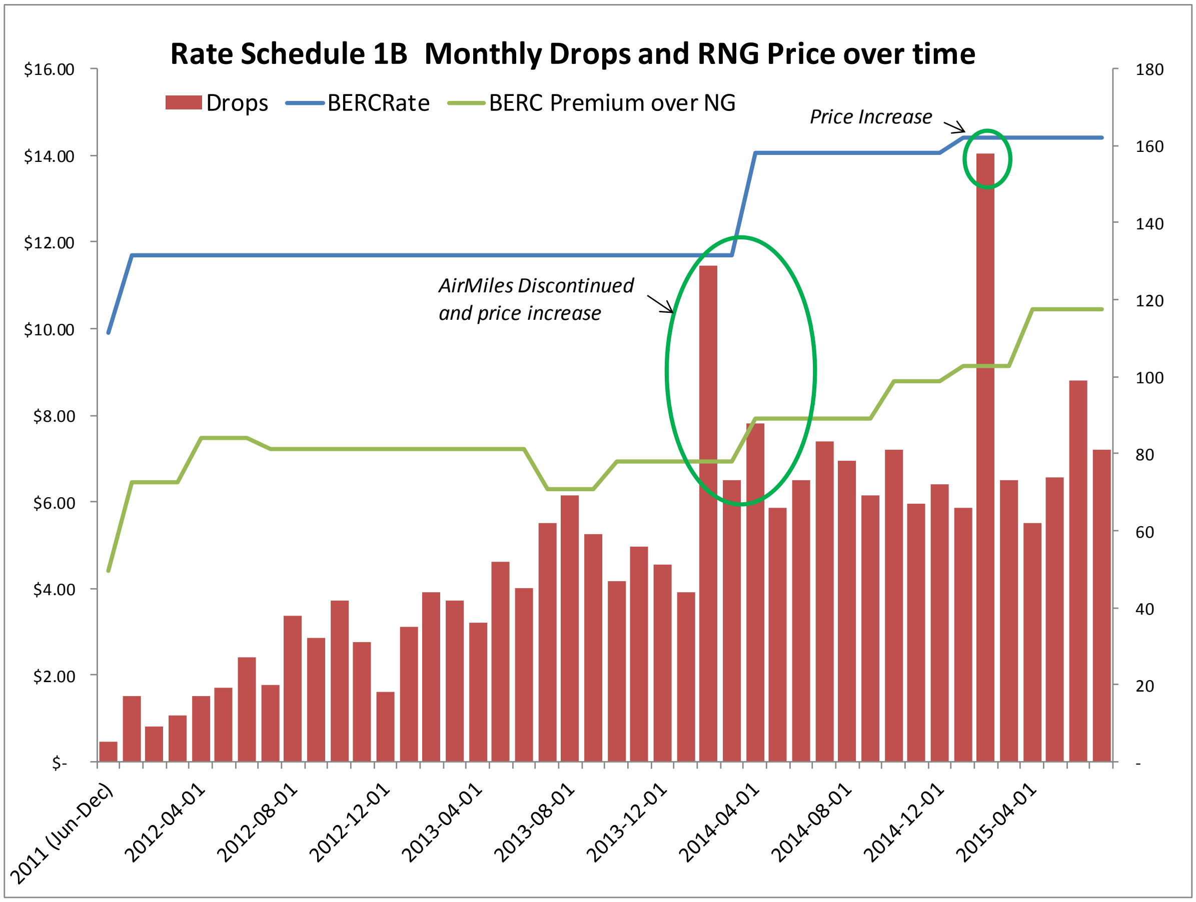
FEI notes that the three-month average of customer additions prior to the rate change (the period of October to December 2013) was 200 per month. When compared to the same period a year later, the three-month average was less than 50 customer additions per month.

Figure 4-2: Residential Monthly Additions Compared to RNG Price



In addition to the decline in new customers, there is a clear trend of declining retention, or increasing customer drops, as seen in Figure 4-3 below. The data indicates that the level of attrition spiked upwards in both April 2014 and January 2015 when prices were increased.

Figure 4-3: Residential Monthly Drops Compared to RNG Price



Together the declining additions to and increasing drops from the RNG Program combine to contribute to a change from positive monthly additions of consistently around 100 and 150 a month to a net monthly average loss of 27 customers.

4.1.2 Decline in Small Commercial Enrollment (Rate Schedule 2B)

FEI's experience suggests that commercial customers are even more price sensitive than residential customers. FEI is finding it more difficult to convert interest in RNG into sales due to both the absolute price of RNG and the price premium comparing to conventional natural gas. This is demonstrated in the Figure 4-4 below, showing the net monthly additions from March 2012 to July 2015.

Figure 4-4: Small Commercial Net Monthly Additions Compared to the RNG Price

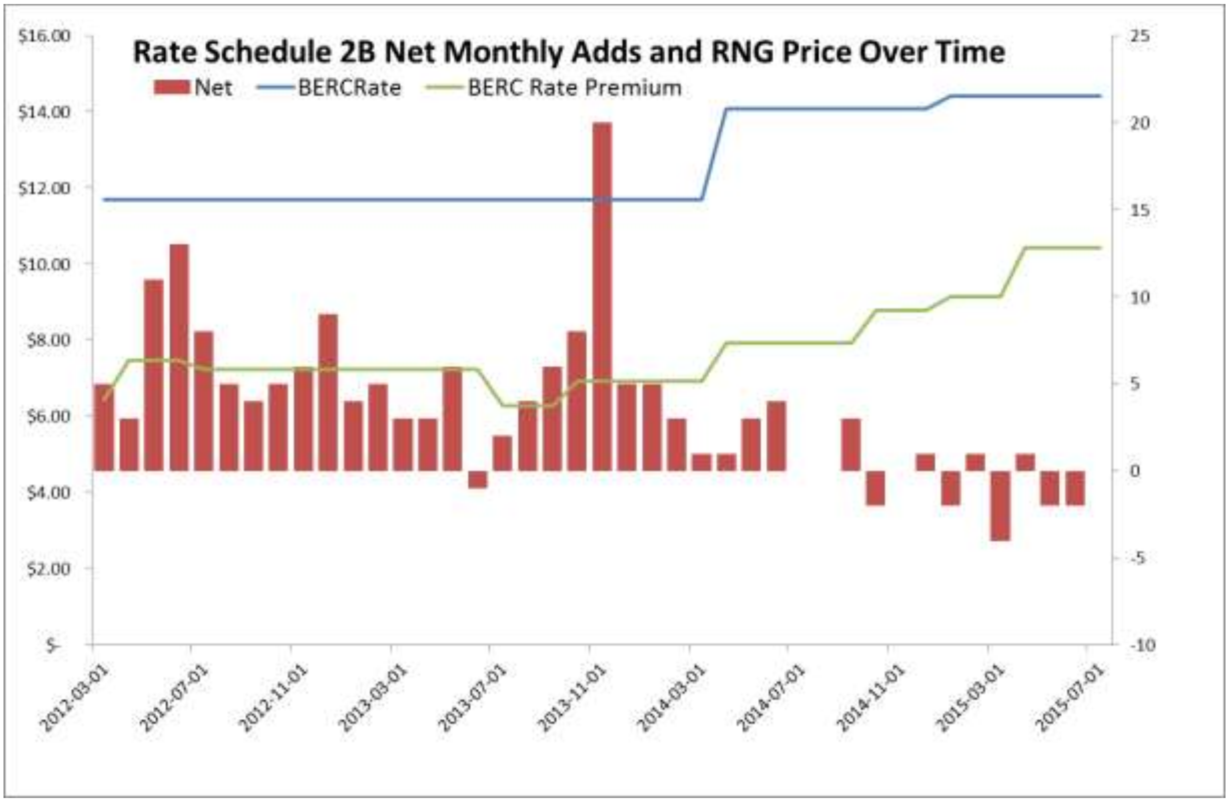
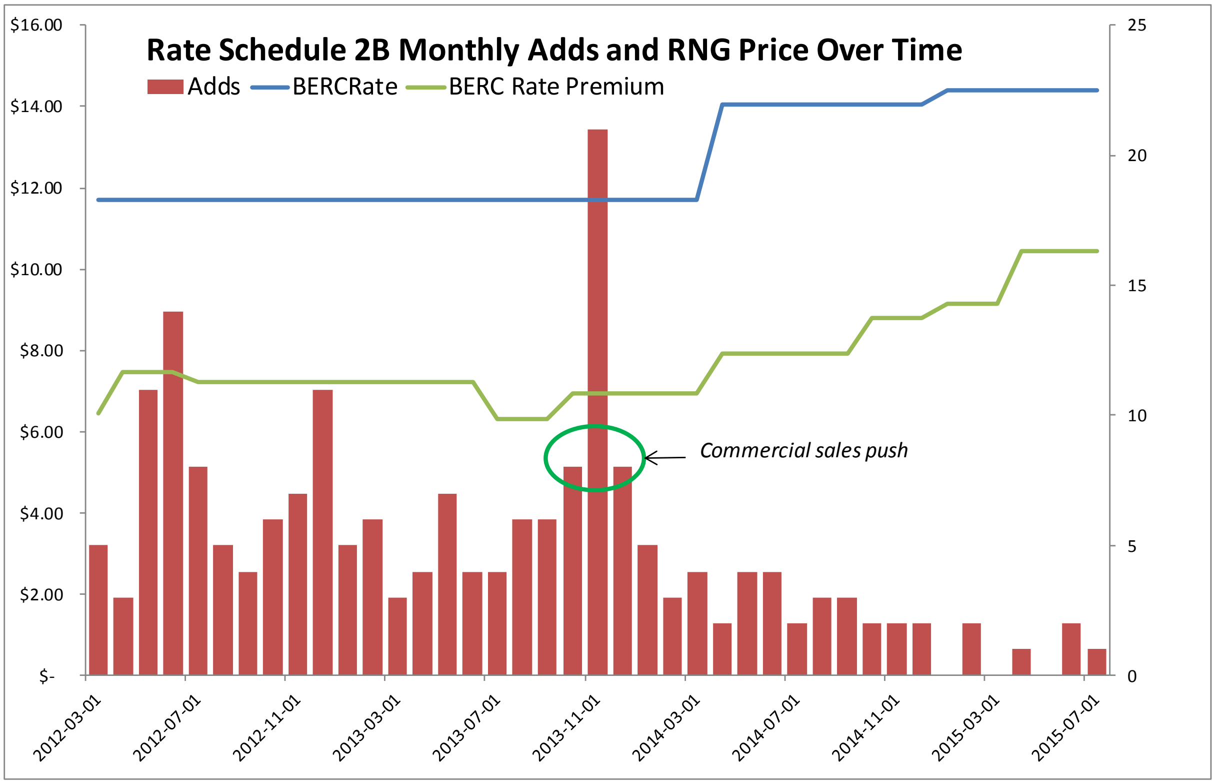


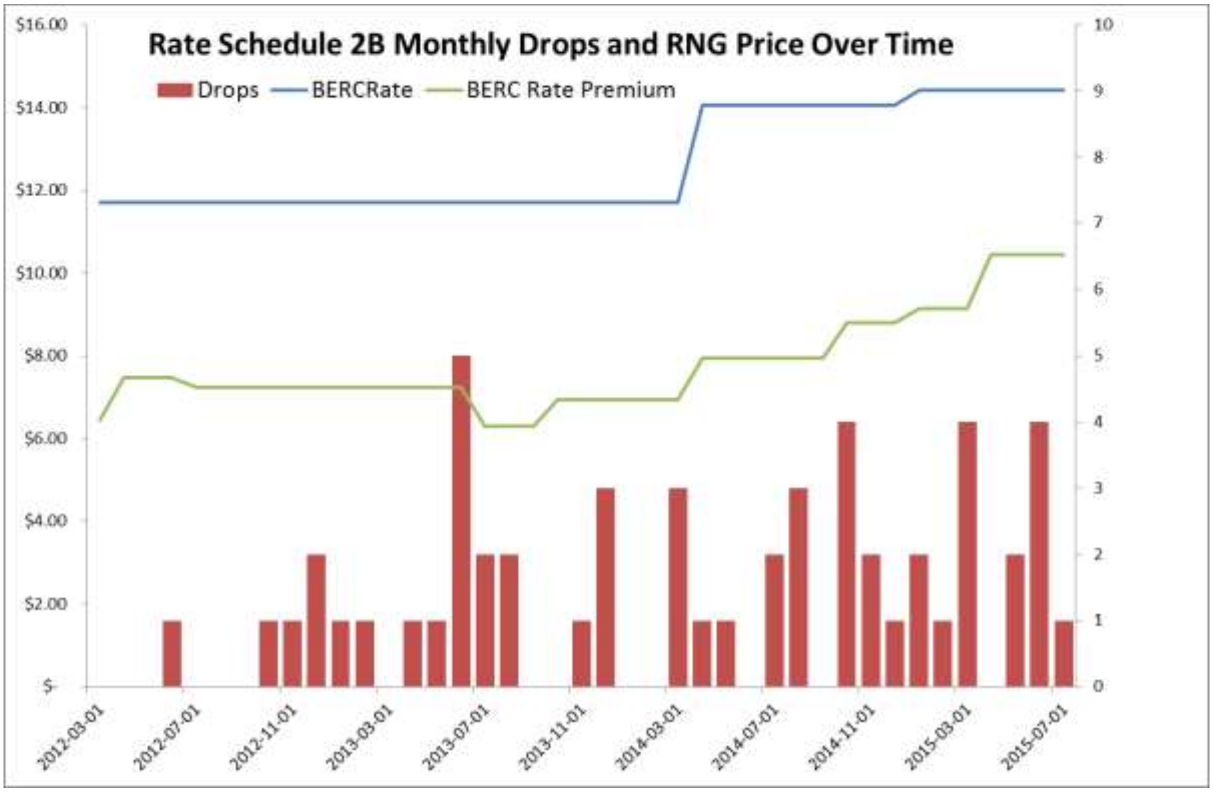
Figure 4-5 below shows the monthly additions in relation to the BERC rate. The monthly additions to the RNG Program show a general pattern of decline as the BERC rate increases. FEI was able to add an average of seven customers per month over the 2013 calendar year while adding an average of three customers per month in 2014 subsequent to the BERC rate increase. The notable spike in sales in the final quarter of 2013 is attributable to FEI temporarily allocating a sales person to undertake a commercial sales push, indicating that the additional expenditure may have had a positive impact on demand.

Figure 4-5: Small Commercial Monthly Additions Compared to the RNG Price



The monthly customer drops from the RNG Program are shown in Figure 4-6 below. Due to the low participation levels, it is hard to conclude whether a correlation exists between customers dropping out of the RNG Program and the BERC rate increase, although an upward trend in customer drops as compared to the 2010-2013 period is visible.

Figure 4-6: Small Commercial Monthly Drops Compared to the RNG Price

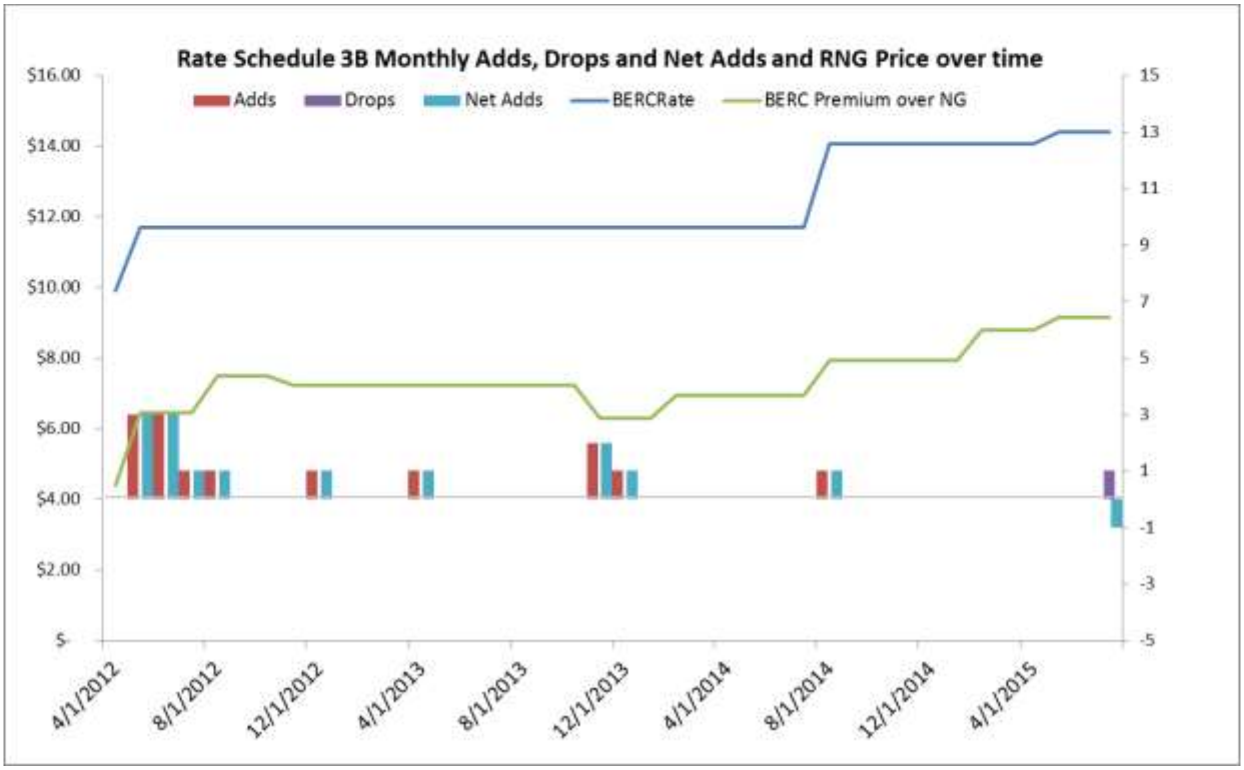


Taken together, the net impact of reduced enrollment and higher abandonments suggests a trend of overall decline in participation corresponding to increases in the premium of RNG to natural gas.

4.1.3 Large Commercial Customers Stagnant (Rate Schedule 3B)

FEI has also tracked the addition of larger volume commercial customers since the inception of the RNG Program. The current number of customers enrolled in Rate Schedule 3B is fourteen. Over calendar year 2014 there was a net increase of two customers and in 2015 (as at July 31st) there have been no customer additions. The customer additions and drops are demonstrated below in Figure 4-7.

Figure 4-7: Large Commercial Adds, Drops and Net - Compared to the RNG Price



A trend is much more difficult to identify in this rate class due to the relatively small number of customers.

4.2 *FEI'S ATTEMPTS TO MITIGATE IMPACT OF RNG PREMIUM*

Prior to seeking approval for changes to the BERC rate methodology, FEI undertook two approaches to mitigate the impact of the high RNG premium on RNG Program adoption. FEI both expanded the RNG offering and reduced overall RNG Program costs.

4.2.1 Expanded Offering

As referenced in Section 3.3, FEI introduced an expanded selection of designated RNG percentages to customers in 2014. The expanded offering allowed customers to designated 5%, 10%, 25%, 50% or 100% of their consumption as RNG rather than just 10%. FEI had hoped that the introduction of these options would result in higher consumption of RNG from customers who chose more than 10%. At the same time, FEI introduced a 5% option, which would allow customers to participate in the RNG Program while paying a relatively lower monthly dollar amount for participating in the RNG Program than participating and choose a 10% blend.

It is clear that existing customers who are committed to the RNG Program have made a deliberate step to increase their RNG use by increasing their designated percentage of consumption. Unfortunately, as described above in Section 3.3, the relative number of customers is still very low in this category and it has not resulted in a significant impact to the annual volume of RNG consumed.

With regard to the 5% offering, FEI has seen an increasing number of participants over time. This is positive for RNG Program participation and reach. However, the lower volume of RNG has a lower impact on any significant RNG inventory.

Based on RNG Program participation, it appears that providing customers with the option of different levels of participation has not made a clear positive impact on enrollment trends.

4.2.2 Reduction in Marketing Spend

Pursuant to Order G-210-13, marketing costs are to be included in the BERC rate. In the circumstances where there is a high premium of RNG over natural gas that causes a reduction in RNG Program participation, increased marketing spend will likely, all things equal, increase participation in the RNG Program. However, increased market spend will result in an increase in the BERC rate, which may then cause less participation in the RNG Program. FEI has thus made the decision to reduce marketing spend at this time as customer feedback (as further described in Section 5.1) suggested that the high RNG rate was the major barrier to participation. At the time FEI had anticipated that the RNG Program was sufficiently advanced that customers would continue to sign up with the lower level of marketing spend. However, as demonstrated above, customer participation in the RNG Program is dropping.

The following table provides a history of the marketing expenditures per year embedded in the RNG Program Overhead Costs.

Table 4-1: Approximate RNG Program Marketing Costs, $ Thousands

Year	Marketing Costs (Approx.)	Comments
2011	$385	Launch year. Included multiple media channels
2012	$301	Targeted approach using most effective channels
2013	$321	Consistent approach as 2012
2014	$167	Comparable spend to 2013 would have added ~ $0.70 per GJ to BERC rate
2015 (F)	$175	Projected spend

4.3 *STATUS QUO OUTLOOK*

In consideration of the experience to date, a five-year outlook of the balance in the BVA with the current cost based BERC methodology indicates that the BERC rate may reach levels close to $17 per GJ. Based on current forward prices, the expected market price of natural gas is anticipated to remain reasonably close to today's prices, thus suggesting that the current premium of $10.438 per for RNG will grow.

Table 4-2 below provides the forecast balance in the BVA and BERC rate if the existing situation continues. Ultimately, if left unaddressed, FEI believes that BERC rate levels with significant RNG premiums will result in a situation where there may be a very limited number of voluntary RNG customers, and, as such, nearly all of the costs of the RNG Program will be left to be recovered from non-RNG customers.

Table 4-2: Status Quo BERC Rate and BVA Five Year Outlook[26]

	2016	2017	2018	2019	2020
BVA Balance ($000)	3,464	9,208	19,088	29,838	42,928
BERC Rate ($/GJ)	16.60	16.51	16.98	16.86	16.97

In accordance with the 2013 Biomethane Decision, FEI is currently notionally banking unsold biomethane. Banking is an important aspect of the RNG Program because it accounts for situations where supply is greater than demand in a given period, and it likewise reduces risk of undersupply (i.e. where demand is greater than supply). FEI has observed both situations since the 2013 Biomethane Decision. For example, during the 2014 calendar year, FEI sold more biomethane than it purchased; but during the summer months of 2014, FEI was purchasing more biomethane than it sold.

At the current BERC rate, FEI is projecting that the situation of supply exceeding demand will be exacerbated and the amount of banked biomethane will continue to grow. While Order G-210-13 provides for the ability to transfer unsold biomethane quantities to the MCRA, FEI believes that this transfer will not increase voluntary participation in the program as it results in a BERC rate that is similar to the status quo outlook for the next several years as shown in Table 4-3 below and Table 4-2 above, respectively.

Table 4-3: BERC Rate and BVA Five-Year Outlook with Transfer of Unsold Quantities[27]

	2016	2017	2018	2019	2020
BVA Balance ($000)	3,464	9,208	9,988	5,834	4,765
BERC Rate ($/GJ)	16.60	16.51	16.98	11.94	9.12

Thus, FEI believes that the solution should take advantage of the ability to transfer unsold quantities of biomethane on a regular basis but must also include modifications to the BERC

[26] Demand outlook based on estimated BERC between $16 and $17 per GJ; unsold quantities over 18 months old remain in the BVA and cost of service is based on existing and forecast supply projects out to 2020.

[27] Demand outlook based on estimated BERC between $16 and $17 per GJ; unsold quantities over 18 months old transferred to the MCRA and cost of service is based on existing and forecast supply projects out to 2020.

rate methodology that will maximize voluntary participation in the RNG Program and minimize the potential impact on non-RNG customers.

5. RESEARCH ON RNG PREMIUM

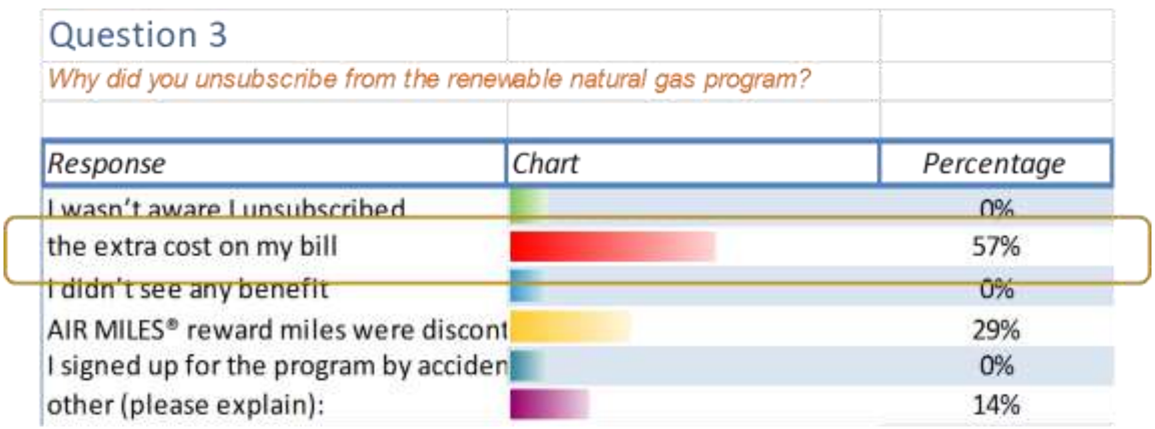
This section provides a summary of the research on RNG premiums and consists of a review of customer feedback, a review of RNG price premiums, a jurisdictional review premium, and a review of green premiums currently available in BC.

5.1 FEI CUSTOMER FEEDBACK

5.1.1 Residential Customer Feedback

In 2014, FEI sent out a survey to previous RNG customers who had dropped from the RNG Program to gain feedback on the influences in their decision to leave the RNG Program[28]. While the response levels were low, 86% of those surveyed dropped out due to the price (extra cost on bill) and the discontinuance of the Air Miles programs as of February 28th, 2014.

Figure 5-1: Excerpt from Dropped Customer Survey


Question 3
Why did you unsubscribe from the renewable natural gas program?

Response	Chart	Percentage
I wasn't aware I unsubscribed		0%
the extra cost on my bill		57%
I didn't see any benefit		0%
AIR MILES® reward miles were discont		29%
I signed up for the program by acciden		0%
other (please explain):		14%

5.1.2 Large Volume Customer Feedback

As described in Section 4, FEI has not had a material uptake in RNG Program participation from large volume customers. In response to this, FEI has spoken to many such customers over the last three years to seek understanding of the sales potential and barriers specific to large volume customers.

FEI has received letters from three existing customers and a letter from a potential customer, outlining their interest in RNG and their specific business case needs in terms of price and price stability to either buy RNG or to buy greater volumes of RNG. These letters are summarized below and provided in full in Appendix D.

[28] Appendix B.

- Vancouver Island Heath Authority (VIHA) has committed to reduce GHG emissions by 33% below 2007 levels by 2020. Currently reductions through energy conservation are having an impact but it will not be sufficient to meet the target. It sees RNG as an option to help with the goal. VIHA currently purchase some RNG but the existing BERC rate is a barrier to increasing its quantity of RNG purchased, and stated that it would consider purchasing greater volumes if the rate were lower. VIHA also indicated interest in entering into a multi-year agreement if it provided the benefit of a stable (and lower) price.
- Thompson River University (TRU) has identified 'increasing sustainability' as a foundational value and strategic priority. To this end, TRU committed in principle to a 10% blend of RNG. However, TRU is still looking at other options for GHG reduction in place of RNG because of the current cost RNG. TRU stated that RNG could become a permanent and larger part of its energy supply portfolio provided lower and stable prices were available.
- The University of British Columbia (UBC) purchases 55,000 GJ of RNG annually, in a blend with conventional natural gas, as the fuel source for a cogeneration plant. The RNG portion of total gas consumption (~37% total) is directly allotted to the electrical production of the cogeneration unit pursuant to its BC Hydro load displacement agreement. Prior to the price increases in April 2014 and January 2015, UBC had plans to increase the percentage of RNG and get additional GHG savings by allocating RNG to heat production as well. UBC stated that with a more competitive and fixed price for RNG it would once again look to increase usage, as well as reconsider a plan to build a much larger co-generation facility, with potential RNG volumes up to 1.0 PJ per year.
- CanGAZ had plans for a 15MW renewable natural gas power generation plant to be built on a site in Surrey, BC. The site and project evaluation was conducted from April to December 2014 and the power was to be sold to BC Hydro under their Standing Offer Program. This project is no longer moving forward due to BC Hydro policy changes; however, the project would have required an estimated 1.1 PJ per year of RNG beginning in 2017. The project's financial model indicated a viable RNG price range from $8 to $12 per GJ.

5.2 RNG PREMIUM DETERMINATION

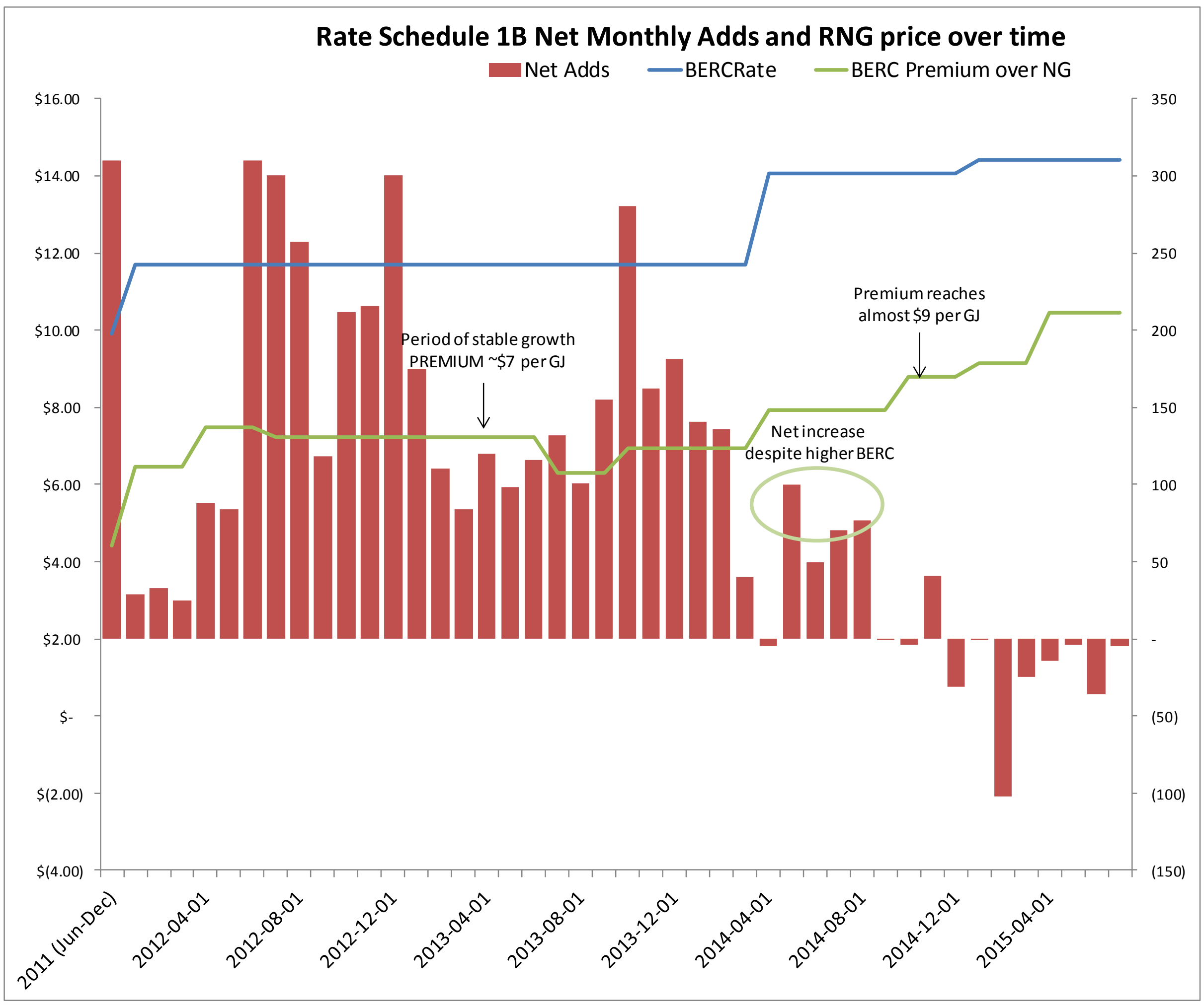
FEI has reviewed the RNG program enrollment since the inception of the RNG Program, reviewed previous research, interviewed utility representatives from other jurisdictions and has specifically discussed RNG pricing with key large-volume customers. In this section, FEI uses enrollment data and previous customer feedback to determine an appropriate premium for RNG.

5.2.1 Enrollment Data Suggests Maximum $7.00 per GJ Premium

FEI has presented the existing monthly enrollment data compared to the relative premium of RNG to a natural gas rate that includes Carbon Tax (Figure 5-2). This figure has been duplicated below with additional notes highlighting the changes in the RNG premium over natural gas.

It can be observed that FEI had its greatest success in attracting and keeping customers when the premium was $7.00 per GJ or less. The trend becomes most obvious during the fall of 2014 when premium of RNG in relation to natural gas (including Carbon Tax) increased to almost $8.79 per GJ. It can also be seen that in that period, the number of RNG Program drops did not increase; rather, the number of additions declined markedly (see Figure 4-2). This leads FEI to conclude that there is a price barrier for new customers when the premium for RNG is too high.

Figure 5-2: Monthly Residential RNG Additions Compared to BERC Rate

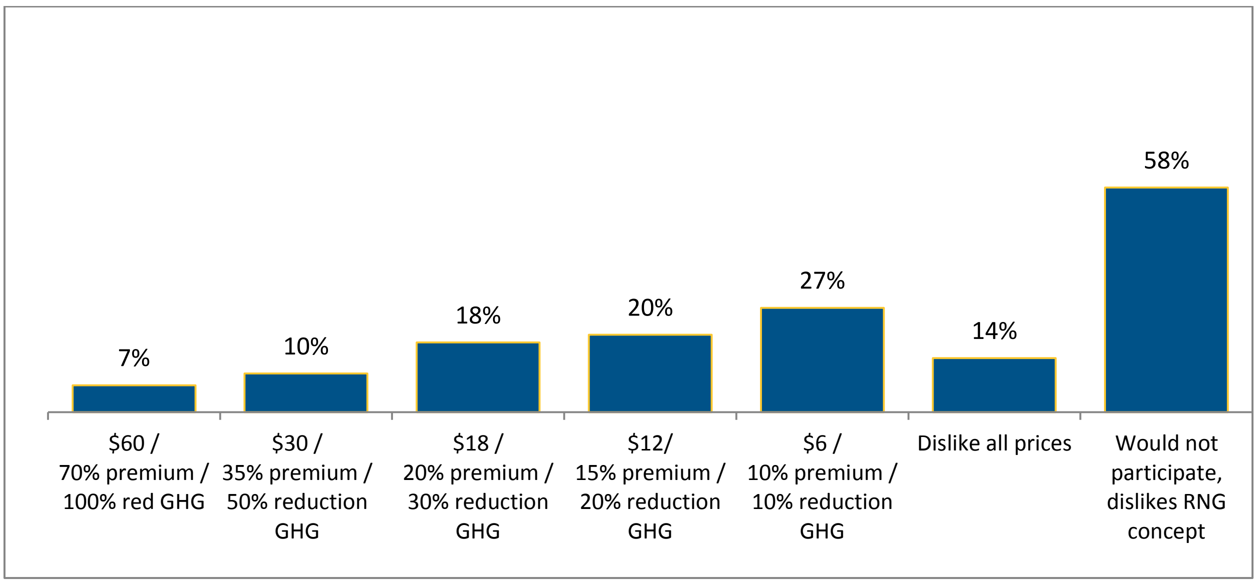


FEI notes that the absolute price of RNG may also impact a customer's decision regarding enrollment in the RNG program. However, in the summer of 2014, FEI was able to continue to add customers despite the higher BERC rate. This is likely due to the fact that the relative premium in these summer months was still reasonably close to the $7.00 per GJ mark. Additionally, the relatively lower overall consumption of natural gas would result in a relatively lower bill.

5.2.2 Previous Research Suggests a Target premium

FEI conducted market research in 2012[29] to better understand potential customer uptake for the RNG Program and provide some guidance for developing a projected demand. In the first study, among other items, price was identified as a major barrier with 58% of respondents, indicating that was their primary reason for not considering RNG[30]. With this consideration in mind, FEI undertook research to understand the price premium that would be tolerable for those customers that were willing to pay an additional cost to participate in the RNG Program. For convenience, a copy of the chart is provided below[31]. The full summary of results can be found in Appendix A.

Figure 5-3: Customer Feedback on RNG Premium



Based on this data, the optimum price point to maximize participation appears to be $6.00 per month assuming a 10% designation of RNG. Based on an average household consumption of 90 GJ per year that additional amount on a bill translates to a per GJ premium of approximately

29 Renewable Natural Gas Monitor and Renewable Natural Gas Monitor: Pricing found in Appendix A.
30 Page 24 Renewable Natural Gas Monitor.
31 Page 11 Renewable Natural Gas Monitor: Pricing.

$8.00[32] (or $72 per year). This is generally in line with FEI's customer enrollment data above showing a decline in enrollment once the rate is more than $7.00/GJ above the CCRA rate.

5.2.3 Jurisdictional Review Suggests Current Premium is too High

This section examines secondary research conducted on utility green energy programs in the North America.

In an effort to identify a competitive rate for RNG, FEI conducted research into the North American utility green energy program marketplace. FEI contacted the United States (US) Department of Energy's National Renewable Energy Laboratory (NREL), the Canadian Gas Association, the Biogas Association and the Coalition for Renewable Natural Gas. FEI also referred to the NREL "Status and Trends in the US Voluntary Green Power Market" reports from 2012 and 2013 and its Top Ten Utility Green Power Program assessments from 2012 to 2014. FEI established that there are more than 100 utilities in the US with green pricing programs and has identified 8 natural gas utilities across the US and Canada with such programs, but none of which is identical in nature to FEI's RNG Program.

To gain additional insight, FEI contacted utilities with:

(i) the most successful renewable electricity programs as determined by customer participation in absolute or percentage terms;

(ii) natural gas utility programs; and

(iii) biomethane-to-electricity programs.

In total FEI contacted 22 utilities, conducted nine interviews and was able to source information on a further eight utility programs. The information gathered through this process is summarized in the following sections.

5.2.3.1 NREL Status and Trends in the US Voluntary Green Power Market 2013

The NREL report included in Appendix C shows that the typical price range for utility green pricing programs varies significantly with the average premium being US$4.92 per GJ equivalent and the median premium being US$4.17[33]. The programs studied are structured in one of three ways: customers can purchase 100% green power, a percentage blend of green energy, or blocks of green energy at a fixed price.

On average, renewable energy sold through green pricing programs in the US in 2013 represented 1.3% of total utility electricity sales (on a mega-watt-hour basis) of the utilities

[32] $6.00/month x 12 months ÷ (9 GJ of RNG) = $8.00 per GJ.
[33] Page 16, NREL Status and Trends in the US Voluntary Green Power Market 2013 (Published November 2014).

offering green pricing programs[34]. By comparison, RNG represents 0.7% of FEI's total volume sales.

At the end of 2013, the average participation rate in utility green pricing programs amongst eligible utility customers was 2.8% with a median of 1.1%. FEI currently has a participation rate of 0.7%[35].

Each year NREL releases its assessment of the leading utility green power programs. Below are two tables showing the top ten programs by customer participation rate (% of customers) and the top ten by green power sales as a percentage of total retail electricity sales in 2014. The participation rates and sales rates of these top programs well exceed FEI's RNG Program.

Table 5-1: NREL Top Ten Utility Participation and Sales[36]

Customer Participation Rate (as of December 2014)

Rank	Utility	Participation Rate	$ Premium per GJ	Monthly premium for average house to go 100% green power
1	Portland General Electric (Green Source)	12.33%	$2.22 (6%)	$7.00-$10.00
2	Sacramento Municipal Utility District	11.76%		$7.50
3	Wellesley Municipal Light Plant (MA)	11.05%	$11.11 (25%)	$20.00-$30.00
4	Farmers Electric Cooperative of Kalona	10.46%		
5	Eversource/United Illuminating	8.93%		
6	PacifiCorp (Blue Sky Usage and Habitat)	8.90%	$2.92	$20.00-$25.00
7	Silicon Valley Power	8.17%	$4.12	
8	Madison Gas & Electric Co	7.97%	$6.78	$10.00-$12.00
9	City of Naperville (IL)	6.23%	$6.94	$6.00
10	River Falls Municipal Utilities	5.88%	$2.78	$7.00-$10.00

*Blank - not available

[34] Page 16, NREL Status and Trends in the US Voluntary Green Power Market 2013 (Published November 2014).
[35] Page 16, NREL Status and Trends in the US Voluntary Green Power Market 2013 (Published November 2014).
[36] Pricing data obtained from interviews and Participation data taken from US Department of Energy Website http://apps3.eere.energy.gov/greenpower/resources/tables/topten.shtml.

Table 5-2: Green Power Sales as Percentage of Total Energy[37]

Green Power Sales (Percentage of Total Retail Electricity Sales in MWh)
(as of December 2014)

Rank	Utility	Sales Rate	$ Premium per GJ	Monthly premium for average house to go 100% green power
1	Waterloo Utilities	23.68%		
2	City of Wellesley Municipal Light Plant (MA)	11.00%	$11.11 (25%)	$20.00-30.00
3	Edmond Electric	10.45%		
4	Portland General Electric (Green Source)	8.96%	$2.22 (6%)	$7.00-10.00
5	River Falls Municipal Utilities	8.14%	$2.78	$7.00-10.00
6	Silicon Valley Power	5.31%	$4.12	
7	Austin Energy	5.20%		
8	Pacific Power (Blue Sky Usage and Habitat)	4.98%		
9	Sacramento Municipal Utility District	4.31%		$7.50
10	City of Palo Alto (CA)	3.23%	$1.14	

*Blank - not available

Based upon the relative participation rates of other utilities, FEI believes that participation can be improved in BC. However, the relative success in participation also appears to be linked to a relatively lower premium than the current BERC rate premium.

5.2.3.2 Utility Interviews

In order to better understand the reasons behind the success of other programs, FEI conducted interviews with the program managers for many of the top performing programs by participation level. The interviews covered price, program design and marketing approaches. The interview findings are combined with the NREL data and secondary research on program pricing and are outlined in Table 5-3 below A detailed summary of the interview results and a list of the interview questions can be found in Appendix B. Please note that all prices in this section are in US dollars.

[37] Pricing data obtained from interviews and Participation data taken from US Department of Energy Website http://apps3.eere.energy.gov/greenpower/resources/tables/topten.shtml.

Table 5-3: Summary of Utility Interviews

Company	Green Energy Price per GJ	$ Premium per GJ (% Premium)	Monthly premium for average house to go 100% green power	% Residential Participation
FortisBC Rate 1 (LML service area) (G)	$19.30	$10.43 net of carbon tax credit (262%)	$72	0.7%
Bullfrog Power - BC (G)	$10.86	3.48 (87%)	$29.87	
Wellesley Municipal Light Plant (E) *		$11.11 (25%)		11.0%
Madison Gas & Electric (E) *		$6.78	$20-30	8.0%
Puget Sound Energy (E) *	$34.72 per GJ or $4 per block. Average customer needs 2 blocks per month to be 100% green energy	$3.47	$10-12	6.3%
Puget Sound Energy (G) *	$4 per block. Average customer needs 2 blocks per month to be 100% green energy		$8	0.2%
North West Natural (G) *	$0.99 per GJ for volumetric program	$0.99 (10%)	$5.50	4.0%
North West Natural (G) *	$5.50 per block. For the average user this equates to 100% green energy			
River Falls Municipal Utilities (E) *	$3 per block of 1.08GJe	$2.78	$5.50	5.8%
Portland General Electric (Green Source) (E) *		$2.22 (6%)	$7-10	15% (combined)
Portland General Electric (Clean Wind) (E) *	$2.50 per block of 0.72 Gje			
WPPI (E) *	$3 per block of 1.08GJe	$2.78		
Green Mountain Power (E) *		$11.11 (29%)	$20	1.5%
City of Palo Alto (G)		$1.14	$5	19.4%
Washington Gas Energy Services (G)		$1.42		
Pacificorp California (E)		$5.41		
Pacificorp Oregon (E)		$2.92		8.9%
City of Naperville -IL (E)	$5 per block of 0.72GJe	$6.94	$20-25	6.2%
Sacremento Municipal Utility District (E)	$3 (50%) or $6 (100%) monthly flat fee		$6	11.7%
Silicon Valley Power (E)		$4.12	$7.50	8.1%
National Grid - Ma (E)		$6.69 to $10.56		
Lake Mills Light & Water (E)	$3 per block of 1.08GJe		$6	
Farmers Electric Cooperative of Kalona (E)	Minimum of $3 per month			10.4%
Xcel Energy - Co (E)	$2.16 for a 0.36GJ block	$6		

Based on the interviews and the results indicated above, FEI makes the following general observations:

- FEI's RNG Program remains the only one directly selling biomethane rather than offsets or carbon credits; however, this does make it significantly more expensive per GJ versus the other NG options researched;
- With the exception of FEI, only two programs have a per premium greater than $7 per GJ;
- Five of the top ten programs by participation level have a fixed monthly pricing option providing cost security to customers. These are typically block-based programs. The monthly participation prices range from $2.16 to $5.50; and,
- There is an even spread of block-based versus percentage-based offerings amongst the programs with the higher participation rates, while several utilities offer both options.

The interview with Madison Gas and Electric (MGE) provided FEI some additional insight. MGE indicated that changes to rates and cost recovery forced the premium on the green energy from $0.01 per kWh to $0.05 per kWh. Not surprisingly, this change resulted in a decreasing participation rate. MGE's green electricity program was originally ranked third in participation (9.3% of customers), but following the change in price that participation dropped (to 7.97%) and MGE is now ranked eighth in participation. From the interview, FEI learned:

- MGE stated that it lost credibility with customers because no one expected renewable energy to get more expensive, even relatively.
- MGE are now working with their regulator to find ways to keep the price steady and avoid large peaks which can impact participation severely.
- MGE found price competition from external offerings has also impacted drop-rates. Some more informed buyers (largely businesses) realize they can buy open market Renewable Energy Certificates (RECs) more cheaply and some residential customer have opted for alternatives such as rooftop solar instead.

FEI's learning has reinforced FEI's conclusion that customers look at alternatives and are sensitive to swings in the premium for "green" products. Further, large swings in the premium for RNG could lead to a credibility challenge, which would in turn create a barrier to increasing voluntary participation.

In conclusion, based upon the interviews conducted, FEI believes that the current premium for RNG is too high if FEI expects to increase participation in the RNG Program.

5.3 PREMIUMS OF OTHER "GREEN" ALTERNATIVES IN BC

In BC, all provincial authorities have to be carbon neutral. This can be done through the purchase of BC approved locally generated offsets that are priced at $25 per tonne of CO2 equivalent. This equates to approximately $1.25 per GJ, significantly lower than the premium for switching to carbon neutral RNG. Businesses not concerned with buying BC approved offsets can buy offsets for less in the North American or global open markets. By contrast 'Status and Trends in the Green Power Market' informs FEI that wholesale Renewable Energy Certificate prices in 2013 were around US$1.20 per MWh (CAN$1.45) or $0.40 per GJ.

Bullfrog Power in BC offers customers the option of purchasing Renewable Energy Certificates (REC) or Green Natural Gas Certificate (GNGC) supporting renewable energy in respect to their electricity or natural gas usage. Bullfrog's electrical customers opt to pay a premium on top of their BC Hydro bill for 100% wind power RECs. The premium for Bullfrog electricity RECs is currently $0.025 per kWh (which converts to a premium of $6.25 per GJ).

Bullfrog's Green Natural Gas customers pay a premium on top of their FEI bill for GNGCs from a landfill project in Quebec. The supply of gas from the landfill project in Quebec differs from FEI's model in two key ways. First, the gas supplied is not "on system" and therefore it does not displace natural gas in BC. Secondly, the project does not clean the gas to meet full pipeline quality standards as FEI's supply does. The gas is injected into a transmission pipeline and diluted by mixing it with large volumes of natural gas pipeline in order to keep the gas quality within specification limits.

The premium for Bullfrog Green Natural Gas GNGCs is currently $3.48 per GJ compared to the current RNG premium of $10.43 over current FEI natural gas rates. This comparison suggests that the premium for RNG should be in the range of $3.50 per GJ to be competitive with Bullfrog Green Natural Gas. When compared to Bullfrog electricity, the indicative premium should be in the range of $6.25 per GJ.

6. ALTERNATIVES CONSIDERED

In light of declining enrollment in the RNG program, which will ultimately result in a greater impact to non-RNG customers, FEI considered four potential alternatives. In evaluating these alternatives, FEI applied the following principles:

- With the RNG program, FEI seeks to encourage and make available the production of RNG in BC and to provide a low GHG offering for customers who wish to directly purchase RNG to meet their own GHG requirements.
- In accordance with the 2013 Biomethane Decision, the costs of the RNG Program should be recovered from voluntary customers to the extent possible.
- The potential rate impact of the RNG Program on natural gas delivery and commodity rates should be minimized.
- Changes to the RNG Program from that approved in the 2013 Biomethane Decision should be minimized.

The four potential alternatives are identified in Table 6-1 below and the estimated impact of each alternative over the five-year period 2016-2020 is provided in Table 6-2 below. Each alternative is discussed further in the following sections.

Table 6-1: RNG Program Alternatives Considered

Option	Description
Status Quo	Continue with cost-based pricing, allow BVA to grow for undetermined period of time
Yearly Clearing	Continue with cost-based pricing, allow BVA to grow but clear inventory older than 18 months on a yearly basis
Universal “Green Portfolio”	Reduce GHGs of entire FEI gas portfolio by transferring all RNG supply to general supply
Market-based rate + Yearly clearing	Set rate at a level that market can bear to encourage maximum participation and clear inventory older than 18 months on annual basis

Table 6-2: Five-Year Average (2016-2020) RNG Program Alternatives Estimated Impacts

	Status Quo[38]	Yearly Clearing	Universal "Green Portfolio"	Market-based Rate + Yearly Clearing
Storage & Transport Rate ($/GJ)	-	$0.019	$0.080	$0.015
Delivery Rate Impact ($/GJ)	$0.245	$0.032	-	$0.016
BVA Balance ($Millions)[39]	$43	$5	-	$19
Residential Annual Bill Impact ($)[40]	$22	$5	$7	$3

6.1 *STATUS QUO*

Under this alternative, the RNG Program would be left "as is" with all the current pricing mechanisms in place. If the RNG Program is left as-is, FEI expects the trend of declining enrollment to continue, which will ultimately result in an increase in costs held in the BVA.

In this scenario, at some point in the future, FEI would have to file an application to transfer costs out of the BVA for recovery from non-RNG customers. As a worst-case scenario, if there were zero participation in the RNG Program, the total amount transferred would be the remaining balance in the BVA. As provided in Table 4-2, the forecast 2016 closing BVA balance assuming the status quo is maintained is approximately $3.5 million and grows to approximately $42.9 million in 2020. These balances represent a delivery rate impact of approximately 0.5% and 5.7% respectively, if recovered from all customers.

The primary benefit of this approach is that the existing, established principles for cost allocation as set out in the 2013 Biomethane Decision are not changed. The mechanism for the transfer of additional costs from the BVA to non-RNG customers has been approved by the Commission in principle, but has not been used to date because the BVA balance has not yet reached an unmanageable level[41].

However, this option does not address the current challenges faced by the RNG Program as described above, including declining program enrollment and the difficulty of entering into larger volume contracts. As such, this option does not seek to maximize participation in the RNG program on a voluntary basis or minimize the potential rate impact to non-RNG customers. FEI therefore rejected this option.

[38] Forecast impact in 2021 of full balance of BVA recovered through delivery rates. This recovery would likely not occur over one year, but spread out over multiple years

[39] Forecast balance as at December 31, 2020

[40] Approximate annual impact based on 5 year average per GJ impact and Mainland Residential customer consuming 90 GJs per year

[41] In the 2012 Application FEI indicated that this limit may 250 TJ of RNG for a period of greater than 24 months.

6.2 *INCORPORATE AUTOMATIC YEARLY CLEARING*

This option maintains the existing BERC rate methodology but adds an annual clearing of the RNG inventory that is greater than a certain age.

The primary benefits of this option are that it limits the costs in the BVA on a yearly basis and it allows for the capture of environmental benefits for the remaining RNG held notionally in storage. By transferring costs out on a yearly basis, it helps mitigate the growth in the BVA balance and as such, the rate impact to non-RNG customers should the entire balance need to be recovered at some point in the future.

As shown in Table 4-3 above, this option results in a BERC rate that is in the range of $16 to $17 per GJ for the first several years. Due to the current age of inventory, the annual transfer of RNG supply to the MCRA is not expected to occur until 2018 and is forecast to be approximately $1.7 million in 2018, $4.2 million in 2019 and $5.6 million in 2020. The remaining difference between the BERC rate and the CCRA rate, after the transfer to the MCRA, would be recovered through delivery rates and is forecast to be approximately $7.4 million in 2018, $11.2 million in 2019 and $9.3 million in 2020.

Like the first option considered above, this approach does not address the current challenges faced by the RNG Program, and does not seek to maximize voluntary participation or minimize potential rate impacts to non-RNG customers. FEI therefore rejected this option.

6.3 *UNIVERSAL GREEN PORTOFOLIO*

A third option would be to transfer all costs and all RNG into FEI's existing natural gas supply portfolio. Conceptually, this would have the effect of reducing the carbon emissions of the entire portfolio while spreading the extra costs associated with RNG to all sales customers. While this option would address the current challenges faced by the RNG Program, this would require a radical restructuring of the RNG Program.

A significant challenge with this approach would be the elimination of the option for voluntary customers to take advantage of the GHG benefits for their operations. The ability to purchase RNG for use in existing natural gas equipment (notionally) while receiving recognition that GHGs are reduced is required for certain customers. The use of RNG allows these customers to reduce their emissions without changing their gas equipment.

Furthermore, this option is not aligned with the Commission's 2013 Biomethane Decision. Notably, it would not seek to maximize voluntary participation or minimize rate impacts to non-RNG customers. In short, this option would involve a complete revisiting of the RNG Program from a regulatory perspective. The rate impact of this option would be an average of approximately $9.9 million recovered each year through the MCRA rates applicable to all sales customers or approximately and average of $0.080 per GJ over the five year period.

FEI believes that while a viable and reasonable alternative, the universal green portfolio approach should only be considered once opportunities to maximize voluntary RNG Program participation are exhausted and as such, it is not FEI's preferred alternative at this time.

6.4 *MARKET-BASED RATE*

The fourth option is a market-based rate that would set the rate for RNG at a level that the market can bear. If priced properly, this option would increase voluntary participation in the program and minimize the potential rate impact to non-RNG customers. The analysis of RNG Program enrollment data, the interviews with other utilities and the market research make it clear that the demand for biomethane could be significantly greater at reduced rates. In particular, large volume customers have indicated an appetite for more RNG if the pricing is more in line with their business plans.

This option gives RNG customers the ability to achieve GHG reductions while at the same time minimizes impact to the natural gas delivery and commodity rates. Through this approach, FEI expects to recover most RNG Program costs from RNG customers. Along with a lower BERC rate, FEI expects higher demand, which will reduce unsold RNG inventory. These two factors together will reduce the potential rate impacts to non-RNG customers as compared to the other alternatives discussed above and as shown in Table 6-2 above.

Under this option, RNG Program cost transparency will remain in place with all costs allocated to the BVA in accordance with the 2013 Biomethane Decision. Although the market based approach may result in a recovery from voluntary customers that is less than the costs captured in the BVA, overall the expected rate impact of this approach is estimated to be $0.015 per GJ and result in lower expected costs to non-RNG customers as compared to other options. This option would also include the annual transfer of RNG supply to the MCRA. Under this scenario, with increased demand, the transfer to the MCRA is forecast to be approximately $1.1 million in 2018, $3.3 million in 2019 and $5.0 million in 2020. Over the five-year period, and including the remaining difference between the average supply cost and the CCRA rate from the transfer to the MCRA, FEI forecasts an average of approximately $2.7 million per year to be recovered through natural gas delivery rates.

Further, this alternative provides the benefit of being able to continue to offer voluntary participation and the opportunity for customers to quantify their reduction in GHG emissions. As such, FEI concluded that the market-based rate option was the preferable option.

7. PROPOSAL

As discussed, FEI has observed a clear negative trend in customer enrollment due to the current premium for RNG above natural gas. FEI also looked at the pricing of equivalent "green energy" in other jurisdictions and found that the current premium for RNG is above other voluntary programs.

To support the success of the RNG Program and in light of the relationship between the premium for RNG, the absolute price for RNG, and the expected trend of upward rate pressure on the BERC, FEI believes that a change in the BERC rate methodology is required and in the public interest. This change in methodology along with the creation of two BERC rates for two different service offerings, a regular transfer of unsold biomethane out of the BVA and an increase in customer awareness and education spending, will collectively increase customer enrollment and ultimately achieve the objectives of the RNG Program, while minimizing cost implications on non-RNG customers.

This section will discuss FEI's proposal for a floating rate based upon a fixed premium and an lower priced option for certain customers willing to enter into long-term agreements. This section also discusses the proposed transfer of unsold RNG inventory as well as FEI's plans to increase marketing and education spending.

7.1 *MARKET BASED BERC RATE*

Based on FEI's analysis and review of existing customer enrollment data, the current RNG rate is now high enough to discourage customer enrollment in the RNG program. As shown above, net customer enrollment has been continually declining since the BERC rate premium over natural gas exceeded $7.00 per GJ. The acceptance of a rate premium of $7.00 per GJ is reinforced by way of the customer surveys and green pricing programs in US and Canadian jurisdictions.

FEI is proposing a market-based BERC rate based on a RNG premium of $7.00 per GJ, which FEI expects will have a greater likelihood of growing demand from voluntary customers. At today's BERC rate, this would mean a decrease in the price that RNG customers will pay. Although this option would result in the recovery of some costs from non-RNG customers, the impact on non-RNG customers will be reduced when compared to the potential impact resulting from reduced or no sales to voluntary customers as demonstrated in Table 6-2 above. The proposed BERC rate will recover a large portion of the costs from voluntary RNG customers while remaining consistent with the principle of the universal benefits of the RNG Program being partially paid for by a broader base of FEI customers and will help maintain an abundant supply of RNG in BC.

7.2 *CREATION OF TWO BERC RATES*

FEI is proposing two BERC rates for two service offerings: Short Term Contract and Long Term Contract RNG customers, respectively. FEI further recommends that the BERC rates are set once per year and the review of the rate change will coincide with Fourth Quarter Gas Cost Reports.

7.2.1 Short Term Contract

This offer reflects residential, commercial and industrial customers that have the flexibility to adjust their participation in the Program (i.e. term, volume, blend, etc.) on a monthly basis. Today, this approach represents all of FEI's current RNG customers. FEI proposes that the BERC rate for customers opting for the Short Term Contract service (i.e. all customers who are eligible for the current biomethane Rate Schedules) is equal to the Commission approved January 1st CCRA rate each year plus the approved Carbon Tax rate plus a premium of $7.00 per GJ. The rate would be set once a year regardless of changes to the CCRA rate throughout the year. The use of a January 1st effective date for annual resetting aligns with changes to other rate components for customers such as delivery and storage and transportation rates and provides rate stability, which is expected to encourage customer participation in the program.

7.2.2 Long Term Contract

Customers that have both a higher volume and a need to contract for a longer period represent a different risk profile and benefit for the RNG program and as such FEI is proposing a separate rate for service to this type of customer. At this time, FEI does not have any equivalent RNG customers under this service type. However, FEI believes that this option will provide long-term security of RNG purchase and is critical for the long-term success of the RNG Program.

Larger commercial and industrial customers who commit to a minimum volume of 500 GJ per month for 10 years or more (or volume equivalent based on combination of volume and years) would be eligible for the Long Term Contract rate. FEI is proposing a $1.00 discount from the Short-Term contract rate because of the relative benefits for FEI and its non-RNG customers.

In general, by entering into a long-term contract there is long-term revenue certainty, a more predictable load throughout the year, and in addition, marketing efforts are no longer required to the same extent for this customer group. Of these factors, the most important is the assurance of revenue from a voluntary customer versus no assurance of demand. This ultimately reduces risk for non-RNG customers because it avoids transfer of unsold RNG to the MCRA.

Long-term RNG sales contracts also better match the long-term nature of the RNG supply contracts which reduces the challenge of balancing RNG and as such, reduces the potential costs to non-RNG customers.

The primary requirement to be eligible for a Long Term Contract is the willingness of the purchaser to enter into an agreement representing a minimum time and volume commitment. Because FEI has not fully negotiated a Long Term RNG Contract, it cannot anticipate all of the future terms and conditions. However, FEI has considered several key elements for its future agreements and provides a summary of the possible terms and conditions that FEI is expected to negotiate with a long-term contract customer and be included to these contracts.

Table 7-1: Summary of Long Term Contract Terms and Conditions

Topic	Notes
Contract Length	• 10 year term as standard, with evergreen option (yearly roll over) available at the end of the term subject to approval of both parties • Five year term possible if volume meets or exceeds ten years multiplied by 500GJ per month • Contract term cannot exceed existing FEI supply contracts
Early Termination Provision	• Early termination possible subject to agreement by both parties.[42] • Standard FEI curtailment guidelines set out in Rate11B. • Customer must 'take or pay' to receive lower rate (may be used to prevent any stranded asset cost)
Quantity	• Individual contract quantities will be negotiated based on customer requirements and FEI available supply
Quantity Exceeded or Not Met	• Volumes not met by FEI would be subject to existing R11B curtailment rules; replacement with credits or a penalty as defined by the contract
Rate Escalation	• Rate to increase at 50% of the Canadian General CPI effective January 1 each year.

7.3 TRANSFER OF UNSOLD BIOMETHANE INVENTORY

In order to maintain a reasonable balance in the BVA, FEI will evaluate and review demand requirements and transfer biomethane out of the BVA on a yearly basis in the event that the inventory of notionally banked biomethane is either greater than eighteen months old or depending on large volume contract requirements, greater than 250,000 GJ. The transfer would further be subject to ensuring that FEI retains at least a 6-month supply for forecast demand. As discussed below, these criteria are reasonable based upon FEI's experience, predicted future agreements and the projected rate impacts.

When considering the transfer of unsold biomethane inventory FEI has applied the following key principles:

- FEI should seek to keep the potential volume and value of inventory at a level that minimizes the annual impact on natural gas delivery and commodity rates;
- FEI should seek to have sufficient RNG to meet future commitments to supply RNG to Long Term customers;
- FEI should seek to keep rate impacts stable on a year to year basis; and

[42] Exclusive of bankruptcy and/or default of payment, early term may be negotiated.

- FEI should recognize the generally accepted industry practice that the vintage of "green energy" has a limit of approximately 2 years before it is considered stale.

With respect to the vintage of the RNG inventory, there is not a defined protocol within Canada. However, in the US, Renewable Identification Numbers (RINs), normally expire after two years. Therefore, at this time, FEI believes it is prudent to conceptually align with this generally accepted industry practice. In order to account for a reasonable period of time in advance of a two-year vintage, FEI proposes to transfer inventory that is older than 18 months.

Despite a transfer trigger of 250,000 GJ, FEI may need to keep additional inventory in order to meet future commitments. Specifically, FEI is now considering the possibility of high-volume, long-term contracts. In the event that FEI has a commitment to sell a significant amount of biomethane, e.g. 500,000 GJ in a year, 250,000 GJ may not be sufficient inventory to ensure that FEI would be able to meet demand for RNG. In this case, an inventory of 250,000 GJ would only cover 6 months of potential supply for a single customer and would not provide any inventory to cover other customer sales. FEI would therefore, hold a larger inventory at the beginning of the year for security of supply to its customers (both the Long Term and Short Term customers).

FEI will continue to monitor the balance between supply and demand of biomethane as a matter of the usual course of business. In the event that FEI believes that it is necessary due to expected demand, it may reduce or forego the transfer of unsold biomethane in that year.

As suggested in the 2013 Biomethane Decision, FEI proposes that the notional inventory be transferred to the MCRA at the prevailing CCRA rate. To align with the annual resetting of the BERC rates, FEI proposes that this transfer is reviewed once per year, and if required, occurs effective January 1. However, as noted above, FEI will monitor the balance between supply and demand throughout the year and if a situation warrants an additional transfer, FEI will apply to the Commission for approval to do so.[43] Further, to the extent that FEI is able to monetize credits or take advantage of Carbon Tax savings from this transfer, any recoveries will be captured in the Commission approved Emissions Regulations deferral account for the benefit of all customers.

7.4 *INCREASE IN CUSTOMER EDUCATION AND AWARENESS SPENDING*

As discussed in Section 4, FEI believes that a modest resumption in spending on RNG Program awareness to a level closer to 2013 levels, in conjunction with a market based BERC rate, would support increased enrollment. Thus, FEI will resume customer awareness and education spending to $300 thousand per year, commencing January 1, 2016.

[43] This may be in the form of a letter to the Commission or as part of the Quarterly Gas Cost Review Process

If the rate is set based on a market price that is comparable to other similar energy offerings, promotion of the RNG Program is the next key element to the RNG Program's success. Customers need to be aware of and fully understand the RNG Program prior to subscribing.

A $300 thousand budget is in line with previous spending levels and, based on past experience, this budget can be used effectively to increase participation and to retain existing customers. Through internal research FEI has identified two barriers to sign up: firstly program awareness and secondly program understanding. Even when aware of the Program, customers display high levels of information needs prior to being willing to enrol in the Program.

With the resumption of education and awareness spending, FEI therefore proposes to focus on media channels that allow a higher levels of engagement, while still fully utilizing less costly internal channels. FEI has identified the following channels as the most likely to achieve the Program marketing goals.

- Existing RNG customer communication: Newsletters, prize lottery, earned media to stimulate word of mouth and referrals
- FEI Natural Gas customer communication: RNG promotions within existing customer communication channels such as the bill to improve conversion of existing customers to RNG.
- Direct outreach: Direct mail, supplier site tours to engage more directly with customers to strengthen connections to the RNG Program.
- Sponsorships and partnership channels: Engagement in events and sponsorships that target our key commercial target sectors and business types
- Digital and social media: Creation of shareable content and stimulation of interest in RNG as a discussion topic leading to improved awareness and interest
- Research: Evaluation of existing channel effectiveness to optimize and refocus education and awareness efforts accordingly.

8. POTENTIAL IMPACT ON NON-RNG CUSTOMERS

Selling RNG at a market-based rate is not expected to have a material impact on the natural gas delivery and commodity rates as shown in Table 6-2 above. The following table provides a summary of the assumptions used to develop the rate impact analysis for the various alternatives and the financial analysis supporting the proposal is provided in Appendix E:

Table 8-1: Summary of Analysis Assumptions

Item	Assumption
Biomethane Demand	Based upon FEI demand model for next 10 years assuming the approved price model. Mass market adoption rates.
Biomethane Cost	Based upon known supply projections with the addition of future potential supply. Future supply costs use expected range of contract prices and volumes based upon existing contracts and the Request for Expression of Interest issued by FEI in 2014.
Market Price for Biomethane	FEI uses the market prices for RNG as proposed in this application. The mass market and long-term fixed prices are based upon natural gas commodity plus two different premiums, ($8.50 and $7.50 per GJ respectively).
Natural Gas Commodity	The natural gas commodity price is used to project a mass market price for biomethane. It is based on natural gas commodity market forecasts from DTN Trading and OneExchange Corporation.
Projected Total Supply	Based upon known supply projections with the addition of future potential supply. Future volumes are projected assuming a certain yearly volume addition based upon the number of projects added in a given year.
Projected delivery volume	Based upon Schedule 7, lines 7 (i.e. MCRA impact volumes) and 28 (i.e. Non-RNG Customer impact volumes) of the Compliance Filing to the 2014-2019 PBR Plan – Annual Review of 2015 Rates, Total Sales and Total Non-Bypass Sales & Transportation Service Volume.[44]

The following two figures provide a forecast comparison of the market-based rate to the cost-based rate for 2016-2020 as well as a summary of the forecast annual impacts to the natural gas commodity and delivery rates under the proposal.

[44] Excluding volumes for Rate Schedule 46.

Figure 8-2: Comparison of Market and Cost Based BERC Rates (2016-2020), $/GJ

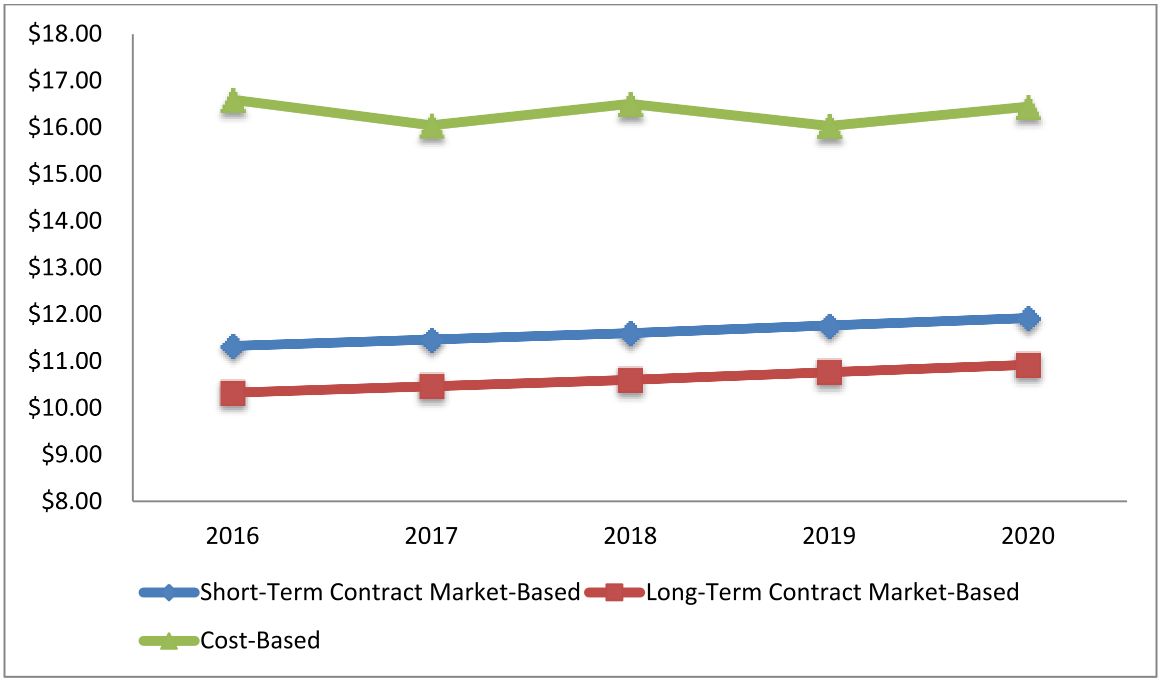
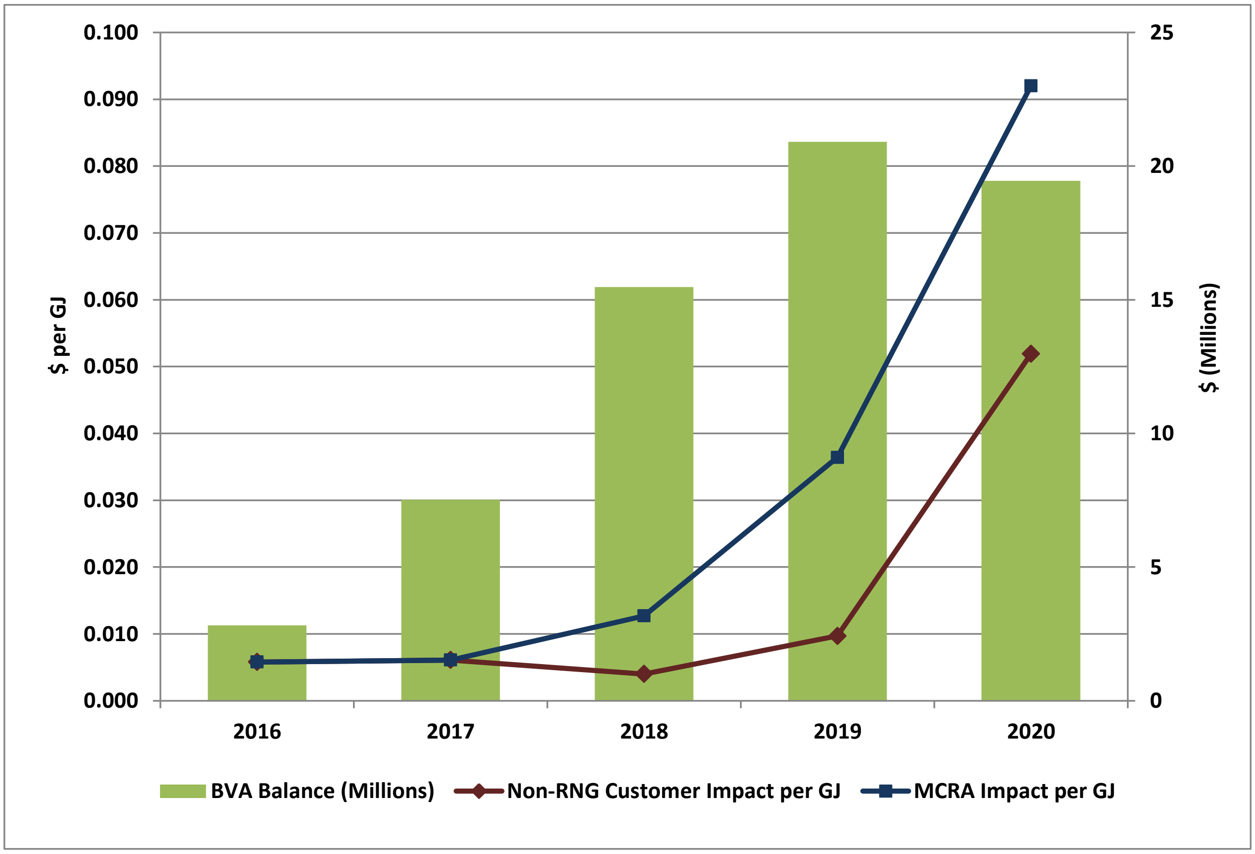


Figure 8-3: Summary of Market-Based Rate + Yearly Clearing Impacts to the BVA, MCRA and Non-RNG Customers[45]



45 Estimated impacts as at December 31

9. ACCOUNTING TREATMENT AND RATE SETTING

As demonstrated in Figure 8-2 above, the market-based rate is expected to be below the cost-based rate. All of the costs of the RNG Program will continue to accumulate in the BVA and include gas costs, capital and operating costs for FEI-owned equipment for the production of RNG and program overhead costs such as administration, marketing and customer education as set out in the 2013 Decision. Thus, while the proposed market based BERC rates are expected to recover a large portion of the forecast costs of the RNG Program certain costs will be recovered from all non-bypass customers. The following describes the mechanisms by which this recovery would occur.

The annual transfer described in section 7.3 above will trigger a transfer of notional inventory from the BVA at the prevailing CCRA rate to the MCRA and thus a recovery of those costs through the Storage and Transportation Charge. Valuing the inventory at the CCRA rate leaves a remaining cost of the inventory embedded in the BVA equal to the difference between the average cost of the RNG supply and the CCRA rate multiplied by the volume of inventory transferred. The 2013 Decision suggested that this amount should be captured in a separate deferral account and recovered from all customers via a rate rider. Rather than shift these costs to another deferral account and use a rate rider for recovery, FEI proposes to simply amortize this amount directly from the BVA into the delivery rates of non-bypass customers. This approach achieves the same result in that this cost is recovered from all non-bypass customers.

Following the transfer of the notional aged inventory, depending on the level of demand, there may be unrecovered capital and operating costs for FEI-owned equipment and program overhead costs that remain in the BVA. As such, FEI proposes that to the extent prior year costs remain in the account they should be amortized through the delivery rates of non-bypass customers in the subsequent year.

Although the transfer of the cost of supply will help mitigate the growth in the BVA balance, FEI expects that the BVA balance will continue to increase. To minimize carrying costs over the long term and smooth out any potential rate impacts, FEI believes that an annual amortization of unrecovered Program costs through the delivery rates of non-RNG customers is appropriate. This approach continues to provide RNG Program cost transparency but limits the build-up of prior year unrecovered costs in the BVA and aligns the timing of the recovery of these costs closer to the period when the costs were incurred.

The result of both transfers is that at the start of each year, the BVA balance would reflect the cost of RNG supply that is available for sale (i.e. supply excluding the aged inventory).

10. CONCLUSION AND CONTINUED OVERSIGHT OF THE RNG PROGRAM

The current RNG Program has had mixed success. The success to date in enrolling customers in the RNG Program shows that customers will voluntarily pay a premium to participate in the RNG Program to reduce GHGs in BC. FEI has more than 6,500 customers participating in the RNG Program representing many rate classes. However, over the past year, FEI has seen a trend of declining net enrollment in the RNG Program as discussed in Section 4.1 above.

Despite FEI's efforts to improve enrollment by offering additional RNG Blends and reducing its RNG related spending, as discussed in Section 4.2 above, FEI has not been able to impact the negative trend.

FEI believes that the primary reason for the trend is the current BERC rate. FEI showed in Section 4.1 that the BERC rate (and the associated premium versus natural gas) has reached a point that is discouraging voluntary customers from enrolling in the RNG Program. FEI has also had feedback from large customers such as UBC that the current BERC rate is too high to consider increasing their purchase volumes. Ultimately, this trend will result in a larger net impact to non-RNG customers as unsold biomethane will be transferred to the MCRA account.

FEI has therefore proposed that the BERC rate be re-set to a level that FEI believes will encourage more participation in the RNG Program, stimulate increased demand for RNG and reduce the impact to natural gas delivery and commodity rates.

Along with the change to the rate, FEI recommends that a transfer of unsold biomethane to the MCRA occurs yearly for inventory that is greater than 18 months old or beyond 250,000 GJs. The transfer mechanism aligns with the guidance that FEI received from the Commission in the 2013 Biomethane Decision. Further, FEI is also proposing a further transfer of unrecovered RNG Program Costs to minimize carrying costs over the long term and mitigate any future potential delivery rate impacts.

This Application does not change the BCUC oversight of the RNG Program. As stated in the 2013 Biomethane Application,

- FEI will continue to seek recovery of costs through its revenue requirements and relevant gas cost filings in the ordinary course;
- FEI will seek approval of the BERC rates through its fourth quarter gas cost reports;
- If FEI requires use of the proposed MCRA Cost Recovery Mechanism, FEI expects to seek approval of the recovery of any costs in the MCRA as part of its quarterly gas reports;
- FEI will continue to file the annual status report for the BVA, which will include details on the costs and recoveries recorded in the BVA; and,

- FEI will continue to seek acceptance from the Commission of new supply agreements pursuant to section 71 of the UCA and in accordance with the criteria approved by the Commission. Biomethane supply and demand updates will be filed to support the need for agreements.

FEI submits that the Approval of this Application will result in an improved RNG Program with improved opportunity to grow the RNG Program while minimizing risk to non-RNG customers. As such, FEI respectfully submits that the Commission should approve the specific orders sought as set out in Section 1 of this Application and in the draft Order.

Appendix A

MARKET RESEARCH SUMMARY 2012

Renewable Natural Gas Monitor

FortisBC

TNS

FORTIS BC™

Contents

Forward (1)

BACKGROUND

As part of FortisBC's vision to be BC's leading energy provider through a broad range of new products and services, Renewable Natural Gas (RNG) was introduced to mainland BC residents in 2010 and to commercial customers in 2011. Customers who choose to participate in the FortisBC RNG program pay $5 more per month for 10% of their natural gas consumption to be comprised of RNG. To date less 0.6% of eligible customers have elected to participate in the program. This is significantly less than the industry average for green energy offerings (2%).

The main business objectives of the current program are to (1) assess the current market potential for RNG and (2) the ideal price point for the product. If the market potential differs from original estimates, why are there differences? Secondary objectives include arriving at a better understanding of the demographic groups most likely to participate in a RNG program and what the motivators of participation might be.

The specific objectives of the research include measuring:

- Differences between current and prior interest levels
- The potential target market(s)
- Likely motivators for participation
- Level of awareness and knowledge of the RNG program
- Barriers to participation
- Attitudes about FortisBC and their impact on participation
- Levels of green behaviours and attitudes

TNS

FORTIS BC™

Forward (2)

METHODOLOGY

A total of 1,003 online surveys was conducted between October 17 and October 26, 2012 among FortisBC customers on the Mainland who receive their bill directly from FortisBC. These customers were self-identified from online panels and interviewed. Customers who have already signed up for the program were disqualified from the survey. This sample target is different from the one used in the 2009 RNG study conducted by TNS, which interviewed all BC households including non-FortisBC customers and Non-Gas users. All comparisons made in this report against the 2009 study, will only reference the FortisBC customer data from 2009.

An online approach was used into order to replicate the data collection methodology from 2009 and to facilitate comparison of the two studies. The questionnaire was developed by TNS in consultation with FortisBC Gas.

The sample is stratified by region, and weighted to reflect the size of those regions in the FortisBC customer database.

Sample Composition

	Actual Interviews	Weighted Proportion of Total
	#	#
Lower Mainland	503	70%
Interior (excluding Whistler, Fort Nelson, Revelstoke & Sunshine Coast)	500	30%
Total	***1,003***	***100%***

Executive Summary

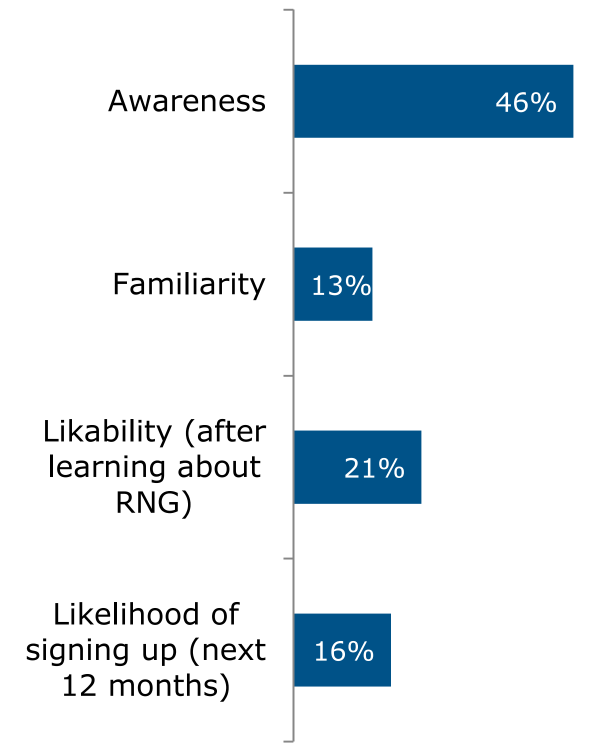
Executive Summary (1)

Significant progress appears to have been made since the introduction of FortisBC's RNG Program. Awareness of the program is growing among FortisBC customers. Like with many new offerings to the marketplace, there is a natural adoption cycle that a product goes through. It appears that RNG may still be in the infancy stages of this lifecycle, catching the attention of early adopters, and those who live a green lifestyle and share the same environmental goals as the program. This lifecycle may also be more extended, compared to other products such as consumer package goods, because FortisBC customers appear to be taking a rational, informed approach to purchase.

At this time, several parts of the program still need development. Aided awareness of RNG is at 46%, but the majority of those who say they are aware admit to a very limited level of knowledge about the product. They indicate that they would like to know more about whether the product was available in their area, how it affects their current gas appliances, and the tangible benefits to them. This is further reinforced by clear misunderstandings of the product and how it is distributed. These simple points can all be clarified through future communications about RNG.

The communications design to lift awareness, should continue to rely on emotive elements, because attitudes about the environment and future generations are motivators in consideration of RNG.

RNG Program Funnel



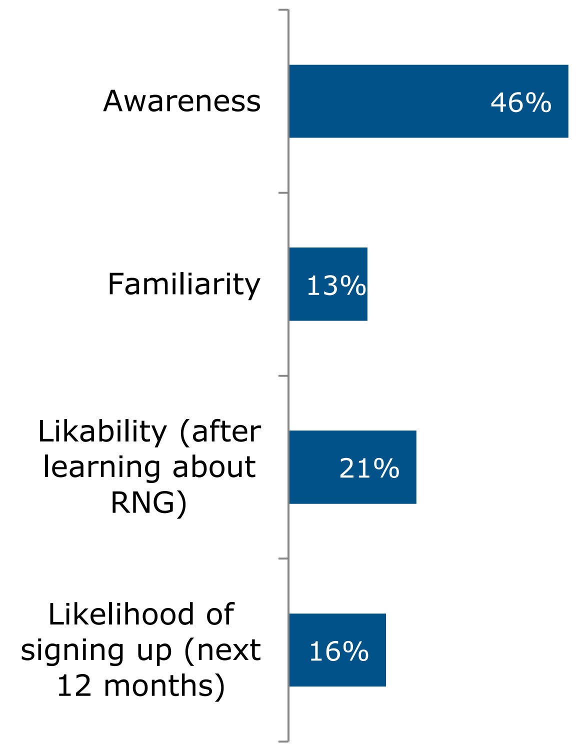
Executive Summary (2)

Increasing familiarity for the product is equally important moving forward. Respondents say they want to know more about RNG and the RNG program before signing up. This suggests that research into the product is a prerequisite; customers want to understand and be comfortable before buying the product.

We recommend more technical information about (1) the product itself, (2) its impact on the environment and (3) safety assurances. These are areas that customers indicate they want to learn more about first. While technical, this information needs to be persuasive and easy to access. And there needs to be clear routing between the bill inserts and other ads that create initial awareness to the educational or technical information that customers will rely on for their research.

We believe that current awareness and familiarity levels can be higher with more communications. Lack of awareness and/or knowledge is currently the second most frequently mentioned barrier to signing up.

RNG Program Funnel



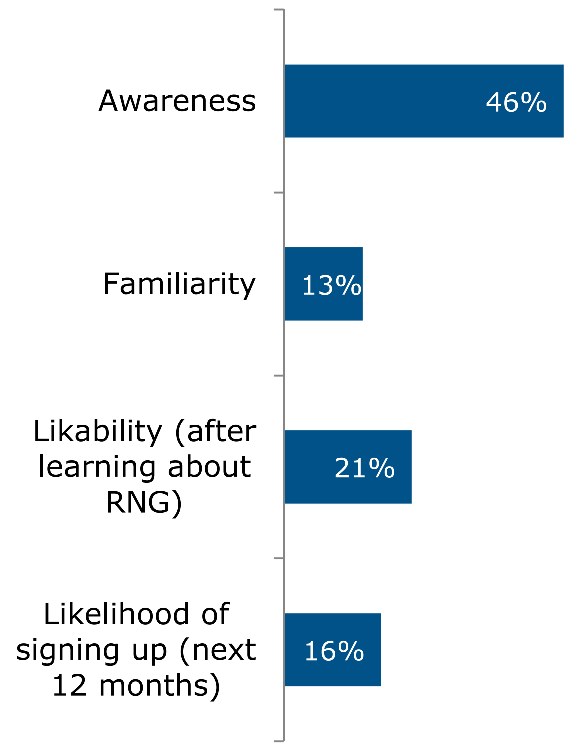
FORTIS BC

Executive Summary (3)

As customers progressed through the survey, they were shown all FortisBC RNG communications so that they could be familiar with the program. Once familiar, they were asked for their opinions of the program and their purchase intentions. It is interesting that learning more about the product led many customers to revise their intention levels – fewer said they would signup after knowing more about the program. We believe this observation was driven primarily by new knowledge about the program's price.

The single most frequently cited comment in regards to both the likeability of the program and program participation is the $5 monthly premium. However, cost is not the only impediment. There is a healthy level of skepticism over RNG because it is new to this market and not everyone believes it is a proven product. We recommend that in addition to spotlighting FortisBC customers who are participating in the program, communications should highlight examples of similar programs in other regions that have been successful. The second source of skepticism arises from disagreement over the cleanliness of RNG for the environment. Part of the disagreement can be eliminated with greater education about RNG. Informing customers about other case studies may be helpful in overcoming this resistance too.

RNG Program Funnel



Executive Summary (4)

Although present participation and consideration rates are low for FortisBC's RNG program, customers are in support of RNG and FortisBC's involvement in RNG. This support has not waivered since 2009. Seventy percent of customers reveal they would like to see FortisBC invest in RNG projects and 71% would like to see FortisBC offer RNG programs. The impediment to low program participation is rooted in a general lack of understanding for the product and some of the current program features. Only 13% of customers are familiar with RNG at present. Conceptually, 52% would sign-up for an RNG program. This figure drops to about 16% when customers learn more about some of the program features.

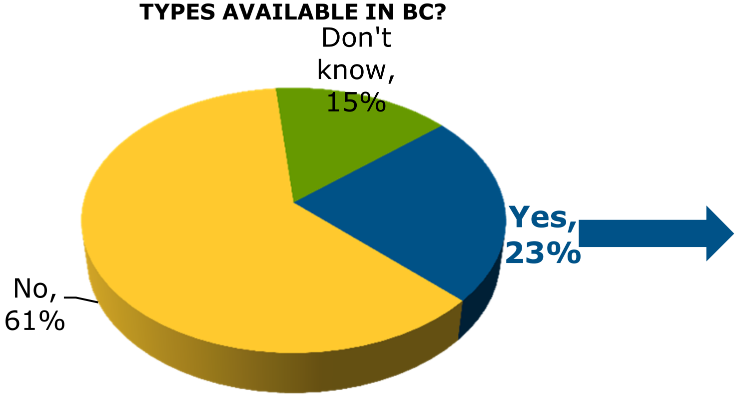
General Summary Of Findings

Awareness And Familiarity

Unaided Awareness Of RNG

Overall, nearly a quarter of FortisBC customers, without being prompted by examples, had remembered either seeing, hearing or learning about unconventional energy sources and fuel types in the past year. Twenty percent of customers said they recall coming across communications about solar power and 18% mentioned wind power. RNG is also quite top-of-mind, as 17% of customers recall reading or hearing about this energy source.

IN THE PAST 12 MONTHS, HAVE YOU SEEN, HEARD OR LEARNED ABOUT ANY NEW ENERGY SOURCES / FUEL TYPES AVAILABLE IN BC?



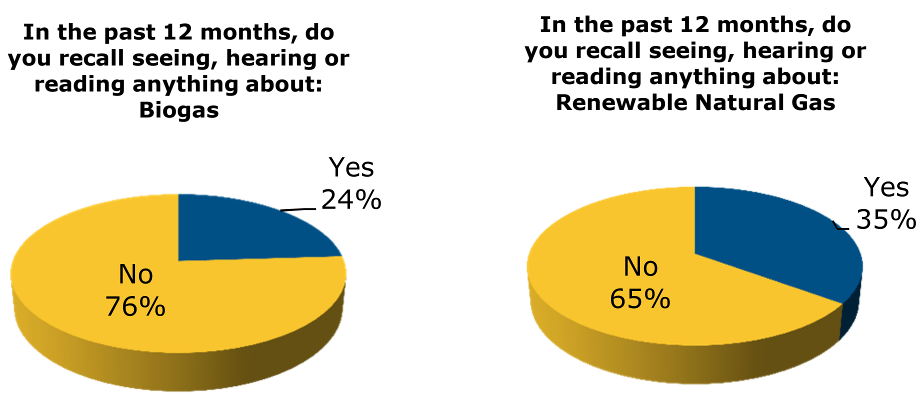
Base: Total Respondents (n=1,003)

Top Alternative Energy Sources Recalled	
Base:	(226)
Solar Power	20%
Wind Power	18%
Biogas/RNG	17%
Geothermal	7%
Electric Energy	7%

Q1A: In the past 12 months, have you seen, heard or learned about any new energy sources / fuel types available in BC?
Q1B: What type of new energy source or fuel type did you see, hear or learn about?

Aided Awareness Of RNG

RNG communications appear to have reached a considerable proportion of FortisBC customers in the window since the campaign's launch. When prompted and asked about seeing, hearing or learning about specific unconventional fuels, "RNG" (35%) resonated more with respondents than "Biogas". In total, slightly less than half (46%) recalled at least one communication about either "RNG" or "Biogas".



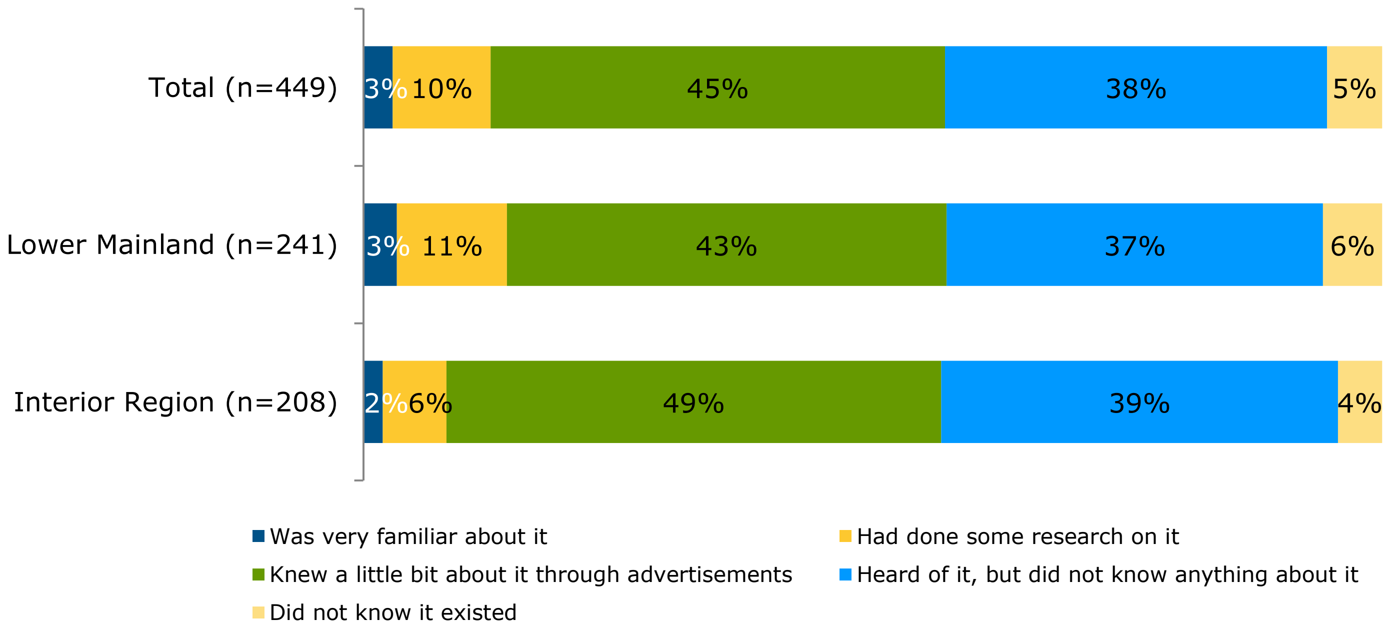
	Total	Lower Mainland	Interior Region
Base:	(1003)	(503)	(500)
Combined % of Yes	46%	62%	51%

Base: Total Respondents (n=1,003)

Q2C: In the past 12 months, do you recall seeing, hearing or reading anything about: Biogas
Q2D: In the past 12 months, do you recall seeing, hearing or reading anything about: Renewable natural gas

Familiarity

However, the product and/or communications have not really gained the attention of customers. Only a small proportion of customers have looked into the new offering. Overall, only 3% of customers indicated they were either very familiar with "RNG" and another 10% revealed they researched the product. Lower Mainland respondents are nearly twice as likely as Interior respondents to be very familiar or have researched "RNG" in the past.



Q10: Before today, how familiar were you about renewable natural gas?

Recall Of RNG Communications

Of those respondents who said they had seen, heard or read about "RNG" in the past year, over a third claim to have seen it on TV. Therefore some of the communications recall is not accurate or is confused with other ads. About a quarter of these customers did indicate they either read about RNG in a bill insert or the newspaper, and 11% of Lower Mainland customers recall the radio ad.

	Total	**Lower Mainland**	**Interior Region**
Base:	(627)	(306)	(321)
TV	35%	37%	31%
Bill insert	25%	25%	23%
Newspaper	24%	25%	21%
Word-of-mouth from friend, neighbour	11%	13%	7%
Radio	7%	11%	0%
Magazine	7%	6%	7%
Internet banner or ad	5%	5%	5%
Local event / sponsorship	2%	1%	2%
Contractor / trades person	1%	1%	1%
Hardware store	1%	1%	1%
Billboard	<1%	<1%	<1%
Other	6%	5%	7%
Don't remember	24%	22%	28%

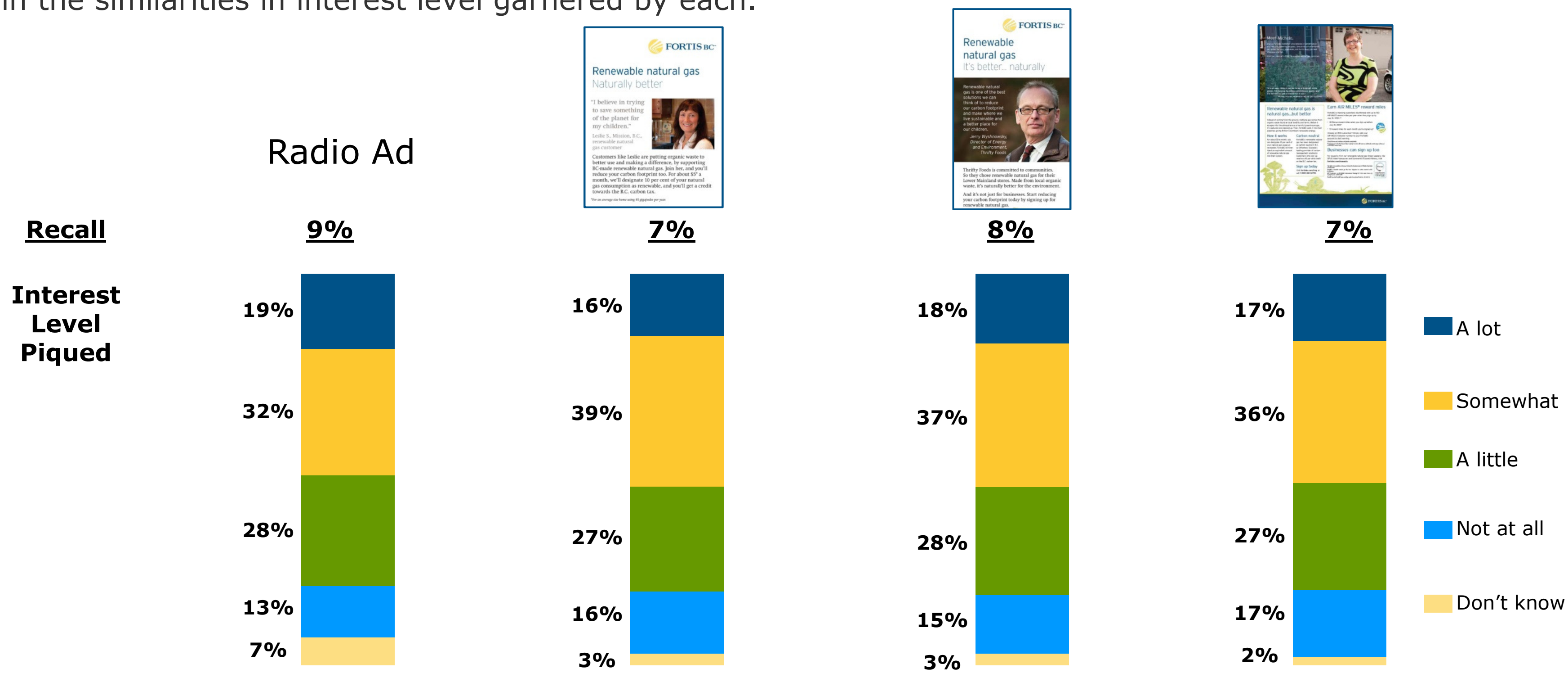
Q6: You indicated earlier that you recalled seeing, hearing or reading about renewable natural gas. Where did you see, hear or read about renewable natural gas in the past 12 months?

TNS

FORTIS BC

Summary Ad Diagnostics

Recall and interest levels for each communication in the campaign are very similar. The communications tend to catch the attention of older customers and those more likely to sign up for the product. Because the content and messaging is very similar and consistent across the four communications tested, this may explain the similarities in interest level garnered by each.

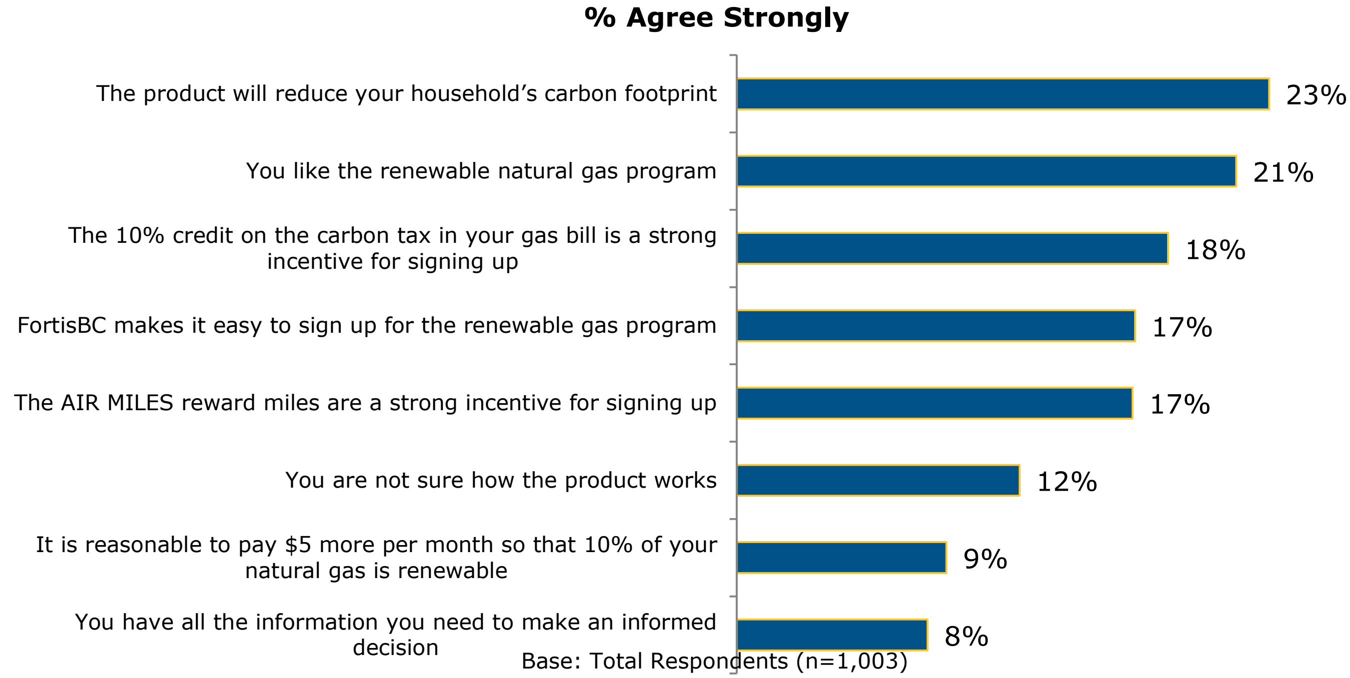


Q7: Do you recall seeing/hearing this communication in the past 18 months?
Q8: To you, what is the main message of this ad?
Q9: How much did the communication pique your interest in the renewable natural gas product?

Likeability Of RNG Program

Opinions About The Program

There is scepticism over the effectiveness of the RNG program. Some of this sentiment may simply stem from a lack of knowledge about the product. However, after seeing the communications, the majority of customers did not appear to be won over by the incentives and program benefits. Less than 25% of respondents strongly agree with any of the benefits or incentives around FortisBC's "RNG" program. Also, 12% are not sure how the product works and only 8% think they have all the information they need to make a decision about enrolment in the program.



Q15: Based on what you know and have seen from the earlier communications, please indicate your level of agreement about FortisBC's renewable natural gas program:

FortisBC's RNG Program Dislikes

The greatest source of discontent with the RNG program stems from the extra fees that customers will have to pay. This suggests that customers do not see an appropriate return or value for the extra fees they would have to pay. There are some lesser secondary reasons for disliking the offering. Some of these reasons arise because customers disagree RNG is a clean energy source or want to see evidence that this new technology works first.

Costs

"$5 monthly charge"
"the cost is too high, incentives are not worth the extra costs involved"
"It costs more than regular natural gas"
"More $s out of my pocket for no reason"

Energy is not clean

"Organic waste disintegrates naturally quite quickly so it would not reduce our carbon footprint in the future. Why go through the extra expense of processing it into fuel?"
"if anything is being trucked (waste) to a plant then it is not "carbon neutral""
"Don't like the idea of using animal waste and don't want to pay more for our natural gas"

Distrust

"It is another way to pick people's pockets by telling them it will reduce our footprint"
"seems phoney"
"a scam to make more money for fortis"

Unproven

"Not fully tested yet"
"I don't want to take a chance on messing up my system by using it. Will wait until more popular and has a track record"

Q16: What in particular do you dislike about FortisBC's renewable natural gas program?

TNS

FORTIS BC™

Consideration and Intentions

Opinions On FortisBC's Involvement With RNG Projects

Support for FortisBC investing in RNG projects remains strong and there has been a slight increase in the number of customers who believe FortisBC should be the organization offering an RNG program.

Should FortisBC Be Investing In RNG Projects

	2009	2012
Base: Total respondents	(799)	(1,003)
Yes (8-10)	70%	70%
Maybe (4-7)	27%	27%
No (1-3)	1%	1%
Decline	2%	2%

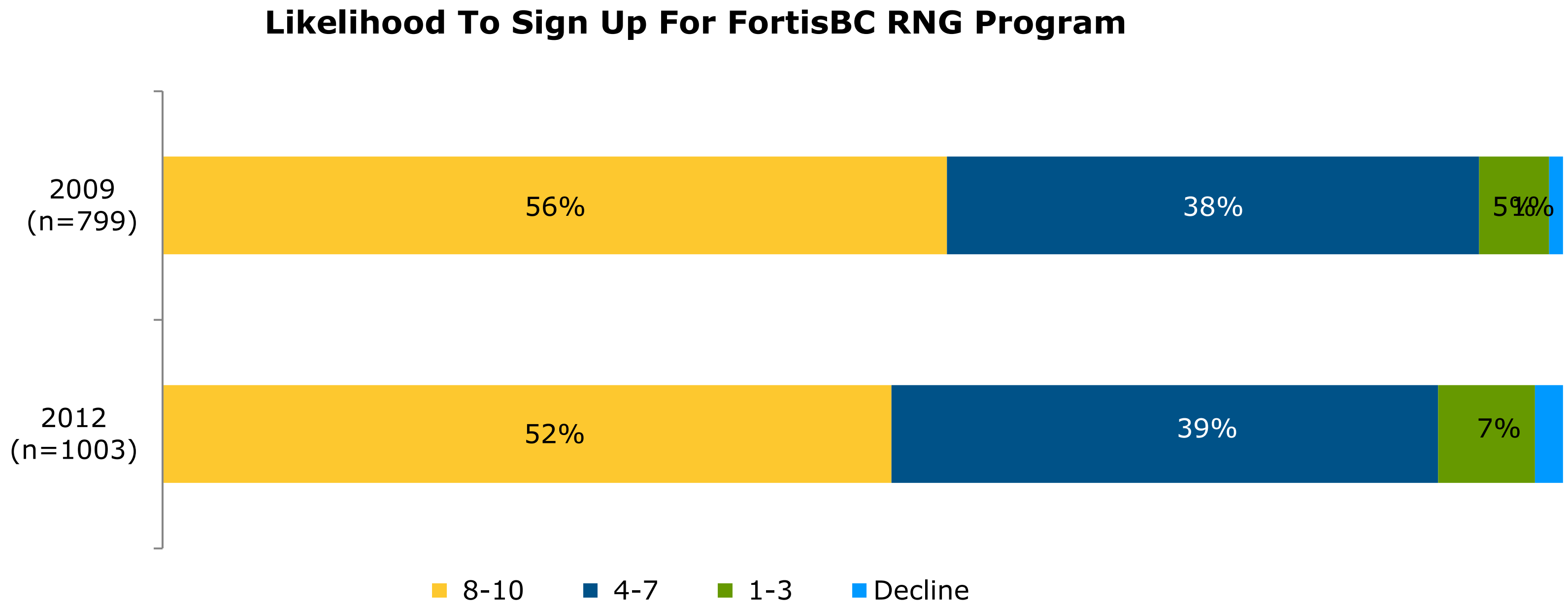
Should FortisBC Offer A RNG Program

	2009	2012
Base: Total respondents	(799)	(1,003)
Yes (8-10)	66%	71%
Maybe (4-7)	31%	27%
No (1-3)	2%	1%
Decline	2%	2%

Q3: (On a scale of 1 – Definitely not to 10 – Definitely) Do you think FortisBC should be investing in RNG projects?
Q4: (On a scale of 1 – Definitely not to 10 – Definitely) Do you think FortisBC should invest in offering a RNG program to its residential customers?

Likelihood To Sign Up For FortisBC RNG Program

However, the self-reported likelihood of signing up has declined slightly from three years ago, prior to the introduction of RNG in the province. There may be several reasons for this, including differences between how customers may have originally envisioned the product compared to current product features.



Q5: (On a scale of 1 –Not very likely to 10 – Definitely) All things being equal, if FortisBC offered a RNG program?

TNS

FORTIS BC™

Motivators For Enrolling In FortisBC RNG Program

Another source of the lower levels of interest may lie in lower general motivation to sign up for the program. This is highlighted in fewer number of customers offering reasons for signing up, compared to three years ago. For example, *doing the right thing*, is not as strong a motivator as in 2009. The strongest motivators have changed slightly from *providing for future generations* to *preserving nature*.

Motivations For Signing Up

	2009	2012
Base: Total respondents that are very likely to sign up for a FortisBC RNG program	(570)	(901)
Preserving nature	76%	65%
Providing for future generations	75%	60%
Doing the right thing	73%	49%
Human health	63%	44%
Supporting local farmers by providing income for their waste streams	62%	49%
Promoting new technologies	61%	45%
Supporting local developments	48%	33%
Being on the cutting edge	13%	9%
Pricing / low price / cost efficient	5%	-

Most Important Motivation For Signing Up

	2009	2012
Base: Total respondents that are very likely to sign up for a FortisBC RNG program	(570)	(901)
Providing for future generations	26%	21%
Preserving nature	20%	24%
Doing the right thing	21%	14%
Human health	10%	9%
Promoting new technologies	8%	6%
Supporting local farmers by providing income for their waste stream	6%	7%
Supporting local developments	2%	2%
Don't know	3%	-

Q20: What if any, would be your motivation for signing up for such a program? (select all that apply)
Q21: And what would be your most important motivation for signing up for such a program? (select one only)

TNS

FORTIS BC™

Barriers to Sign-Up

Customers mention cost and lack of information as the two main barriers to signing-up. These comments are not surprising for a new product that requires customers to pay more. However, there will be a need to evolve the communications over time to answer or clarify questions from customers trying to understand the smaller details of the product. Clarification on the availability of the product, the benefits, the carbon credits, and impact on appliances would be useful in future mass communications. Separate channels should be setup for customers who wish to learn more about the technical details including safety, effect on the environment and how RNG is produced. This will assist those who are considering the product in their decision regarding RNG.

Additional information/considerations before making decision

	Total
Base: Total ….	(591)
Price	39%
Effect on environment	5%
Availability in my area	3%
Safety of the product	3%
Information on how gas is processed	3%
Effect on my appliances	3%
Benefits / advantages / savings	2%
Information on carbon credits	2%

Main reasons for not considering RNG

	Total
Base: Total ….	(289)
Extra cost	58%
Not enough information	7%
Other miscellaneous	20%

Q13: What factors are you considering or what information would you want to know more about?
Q14: What are your main reasons for not considering renewable natural gas?

Likelihood To Sign-Up For RNG Program (1)

Based on a brief description of RNG at the beginning of the survey, customers were asked if they would (conceptually) participate in the program. Approximately 52% indicate that they would (see page 22). These customer are more likely to be middle aged (35-44), residing in townhouses, and have a contract with a gas marketer.

However, as customers progress through the survey, they are shown FortisBC's RNG communications and familiarized with the program's features. After this exposure, customers are asked a second time, the likelihood that they would signup for the program (but over the next 12 months). Intention rates decline drastically as only 16% indicate that they would be "very likely" to signup. Those most likely to signup include households who are with gas marketers and those respondents who indicate that they were already very familiar with the product.

Likelihood Of Signing Up

	Total
Base: Total Respondents	(1,003)
All customers	**52%**
35 to 44 years old	57%
Use Gas Marketer	66%
Townhouses	57%

Likelihood Of Signing Up in Next 12 Months

	Total
Base: Total Respondents	(1,003)
All customers	**16%**
Use Gas Marketer	25%
Was Already Very Familiar with RNG	31%

Q5: All things being equal, how likely would you be to sign up for a FortisBC renewable natural gas program?
Q12: How likely are you to sign up for renewable natural gas in the next 12 months?

Likelihood To Sign-Up For RNG Program (2)

The results from the previous page raise a very important discussion into why stated intentional behaviours would change after learning about the FortisBC RNG program features. Some things are clear from these results. For example, demographics do not factor into customers' intentions. If they did, we would see differences in intentions between demographic groups. We have observed that signup appear partly driven by attitudes (e.g., cleaner environment and leaving a better world for future generations). But these intrinsic values would not have altered during the course of this survey.

This leads us to believe that the program features are not what customers originally envisioned when the concept was described. The price was a point of contention for many customers. Skepticism over the effectiveness of the product was another point of contention. It was also observed that more questions were triggered about the product and program for customers, leading them to rein in their initial enthusiasm.

The segment of the FortisBC customer base with gas marketers are an interesting finding that emerged from the results. Why would this group be more likely to embrace the RNG program. Is this group more comfortable signing up for different programs? Are they more comfortable with fixed rates? Is this a segment that the RNG program should target with increased communications?

Q5: All things being equal, how likely would you be to sign up for a FortisBC renewable natural gas program?
Q12: How likely are you to sign up for renewable natural gas in the next 12 months?

Demographic Profile

About Customers

Demographic Profile (1)

		Region	
	Total	Lower Mainland	Interior
Base Size	(1,003)	(503)	(500)
MAIN SPACE HEATING FUEL			
Natural gas	86%	84%	89%
Electricity	9%	11%	7%
Wood	2%	1%	3%
Other	1%	2%	1%
Don't know	2%	3%	<1%
HOME OWNERSHIP			
Own	83%	81%	86%
Rent	15%	17%	13%
Other	2%	3%	1%
TYPE OF DWELLING			
Single-Detached home	76%	75%	78%
Townhouse	12%	16%	9%
Condominium	3%	4%	2%
Apartment	1%	2%	0%
Other	7%	4%	11%

Demographic Profile (2)

		Region	
	Total	Lower Mainland	Interior
Base Size	(1,003)	(503)	(500)
Gas Marketer			
Yes	17%	18%	16%
No	71%	68%	74%
Don't Know	12%	14%	10%
AGE			
18 to 24 years	1%	1%	1%
25 to 34 years	7%	7%	7%
35 to 44 years	16%	17%	14%
45 to 54 years	20%	21%	19%
55 to 64 years	29%	26%	32%
65 years or more	27%	26%	27%

Demographic Profile (3)

	Region		
	Total	Lower Mainland	Interior
Base Size	(1,003)	(503)	(500)
CHILDREN IN HOUSEHOLD			
0 to 5 years old	9%	11%	7%
Yes	91%	89%	93%
No			
6 to 12 years old			
Yes	14%	17%	11%
No	86%	83%	89%
13 to 17 years old			
Yes	13%	17%	10%
No	87%	83%	90%

Demographic Profile (4)

		Region	
	Total	Lower Mainland	Interior
Base Size			
HOUSEHOLD INCOME			
Less than $15,000	4%	3%	4%
$15,000 to less than $35,000	16%	13%	18%
$35,000 to less than $60,000	24%	21%	27%
$60,000 to less than $100,000	28%	30%	25%
$100,000 or more	13%	16%	10%
GENDER			
Male	31%	35%	27%
Female	69%	65%	73%

Appendix To The Methodology

Appendix To The Methodology (1)

Overview

A total of 1,003 online interviews was conducted between October 17 and October 26, 2012 with a sample of FortisBC mainland customers. Respondents were screened on a number of different criteria. To qualify for this study, the household must be a customer of FortisBC and must received their energy bill directly from the utility. Households currently participating in the FortisBC RNG program were disqualified from this survey (none were disqualified on this basis). Furthermore, the respondent completing the survey must be one of the members of the household responsible for making energy decisions. Results obtained from this survey provide valuable insights into understanding perceptions of FortisBC and feature preferences for a renewable natural gas program.

Sample Frame And Design

The sample used in this survey was drawn from TNS' LightSpeed online adult panel. A quota cell design was used for this survey to ensure that a specific sampling level was achieved with respect to FortisBC's own regions. The number of completed interviews for each quota group are outlined below.

Sample Design

	Actual Interviews	Weighted Proportion of Total
	#	#
Lower Mainland	503	70%
Interior (excluding Whistler, Fort Nelson, Revelstoke & Sunshine Coast)	500	30%
Total	***1,003***	***100%***

Appendix To The Methodology (2)

Questionnaire Development

The questionnaire was developed by TNS Canadian Facts in consultation with FortisBC. Prior to the start of interviewing, a pretest was conducted over the first weekend of field to ensure the workability of the questionnaire and to finalize question sequencing.

Data Collection

Respondents were recruited from TNS' online panels and directed to the survey site to complete the survey. The results of the fieldwork are summarized in the next page.

Outcomes Of The Fieldwork

	Number	Percent
Number of survey invitations sent	(5303) #	(100) %
Completed survey	1,003	19
Disqualified	1,379	26
Break off	182	4
Quota fail	104	2
Did not respond to survey	3,571	68

TNS

FORTIS BC™

Appendix To The Methodology (3)

Survey Margin of Error

The reader is cautioned that the survey results are subject to margins of error. The overall sampling error for 1,003 total interviews at the 90% confidence level is approximately ± 2.6%. For example, if 50% of all respondents surveyed stated that they have heard of carbon offsets, then we can be sure, nine times out of ten, that if the entire population had been interviewed, the proportion would lie between 47.4% and 52.6%.

When a segment of the entire data is analyzed, the sampling error increases. For example, the overall sampling error for data based on 500 interviews at the 90% confidence level is approximately ± 3.7%. In this case, using the scenario where Lower Mainland respondents surveyed state that recall hearing a radio ad about RNG, then we can be sure, nine times out of ten, that this proportion would lie between 46.3% and 53.7%.

A copy of the invitation and questionnaire used in this survey are appended to this report.

Appendix To Results

Benchmark Metrics

Benchmark Metrics

The following benchmarks were collected in August 2012, as part of the EEC and PowerSense Communications Tracking research. It should be noted that this online research was conducted with the general population in all BC regions serviced by FortisBC (as opposed to FortisBC customers, within specific geographic pockets where RNG has been made available). In the general population, awareness metrics would likely be lower than among the audience surveyed in this study

	Unaided Awareness	*Aided Awareness*	*Ad Recall*
FortisBC RNG	**4%**	**46%**	**7%-9%**
PowerSmart Program	14%	89%	N/A
WorkSafeBC: WorkSense	N/A	75%	23%
GameSense: Play Within Your Limits	N/A	60%	9%
LiveSmart	N/A	34%	N/A

Renewable Natural Gas Monitor: Pricing

FortisBC

TNS

FORTIS BC™

Contents

Forward (1)

BACKGROUND

As part of FortisBC's vision to be BC's leading energy provider through a broad range of new products and services, Renewable Natural Gas (RNG) was introduced to mainland BC residents in 2010 and to commercial customers in 2011. Customers who choose to participate in the FortisBC RNG program pay approximately $5 more per month for approximately 10% of their natural gas consumption to be comprise of RNG. To date less 0.2% of eligible customers have elected to participate in the program. This is significantly less than the industry average for green energy offerings (2%).

The main business objective of this research is to assess the current market potential for RNG and the ideal price point for the product. If the market potential differs from original estimates in 2009, why are there differences?

The specific objectives of the research include measuring:

- Level of interest in RNG at given price points;
- Preference between different program pricing structures; and,
- Differences between current and prior interest levels.

Forward (2)

METHODOLOGY

A total of 401 online surveys was conducted during the week of October 29, 2012 among FortisBC customers on the Mainland (who receive their bill directly from FortisBC). These customers were self-identified from the Asking Canadians online panel and interviewed. The questionnaire was developed by TNS in consultation with FortisBC Gas.

A simple random sample was employed for this study and weighted to reflect the size of those regions in the FortisBC customer database (in conjunction with the main survey).

Sample Composition

	Actual Interviews	Weighted Proportion of Total
	#	#
Lower Mainland	271	70%
Interior (excluding Whistler, Fort Nelson, Revelstoke & Sunshine Coast)	130	30%
Total	***401***	***100%***

Executive Summary

Executive Summary

Preference in pricing models is driven by perceptions of fairness – those willing to participate in the RNG initiative believe everyone should contribute while those who do not wish to participate feel only participants should shoulder the costs. Approximately 42% of FortisBC customers show a strong interest in participating in the RNG program. These customers would prefer to see FortisBC introduce a pricing model that is borne by all customers (instead of being user pay). However, such a universal pricing model will be met with strong opposition from customers who are not interested in the program. The larger customer base is in favour of a user pay program. This is a contrast to 2009, when more customers preferred a universal pay model over user premiums – a possible reflection of the greater awareness and understanding of the program today.

Under a price model borne by all customers, the price increases are less dramatic compared to a user pay model. Because the price increases are smaller, the difference between a 2% increase in commodity prices versus 4% is marginal for those willing to support the program. The larger issue under this pricing model affects FortisBC's corporate reputation – is the organization willing to upset more than half of its customer base with a program that not everybody wants to buy into?

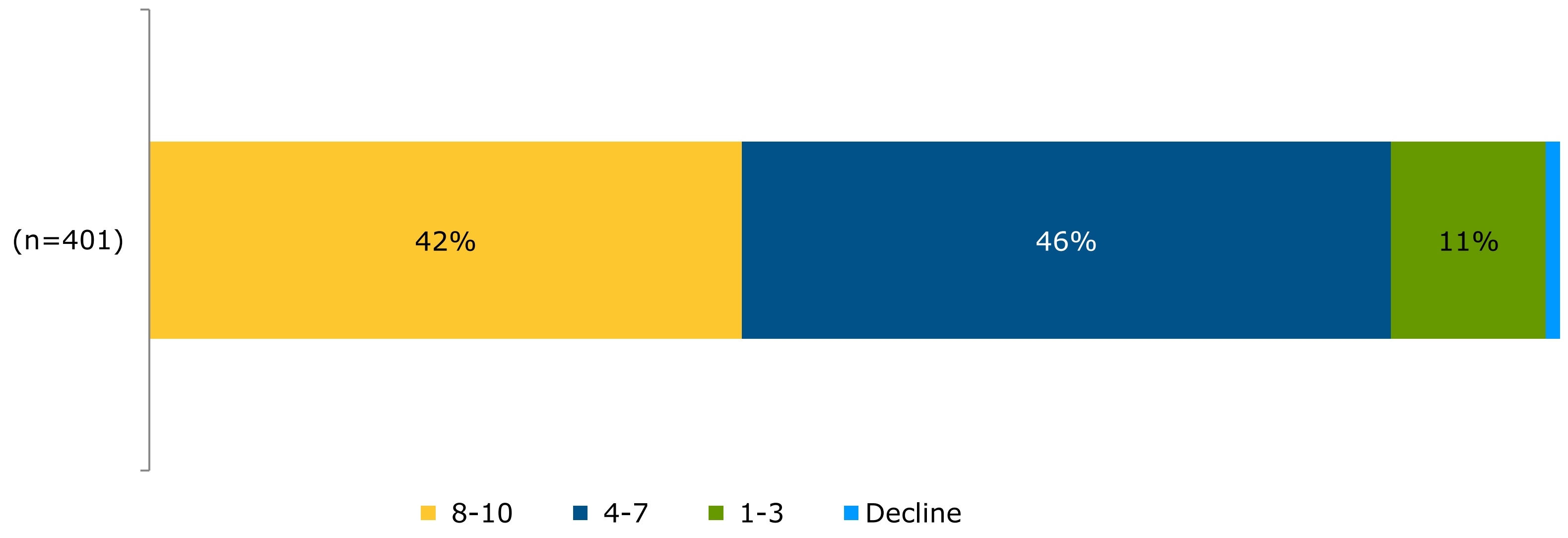
Under a user pay model, there emerges a debate between maximizing the number of participating households versus maximizing the volume of RNG sold. At lower price increases ($12 or less per month) a significantly higher number of households say they would sign up. At higher price points ($18, $30, $60 monthly increases), there are fewer households participating, but they will generate a higher overall level of RNG consumption. Up to 7% of customers are fully committed to the RNG program, indicating they would sign up at the highest price point if it meant a 100% reduction in their GHG emissions. To resolve this divide, we recommend a user pay, menu pricing option. In this option, customers are given the choice of different prices depending on their commitment. Committed customers can pay a higher price point for a greater reduction in their GHG reductions. More price sensitive customers, would have the option to pay a lower monthly increase.

General Summary Of Findings

Likelihood To Sign Up For FortisBC RNG Program

When the concept of renewable natural gas was described to customers, 42% of customers expressed a strong interest in participating in the RNG program. The remaining customers did not express any strong intentions of participating in the program. Customers will be separated by this distinction, when analyzing the results of this study.

Likelihood To Sign Up For FortisBC RNG Program

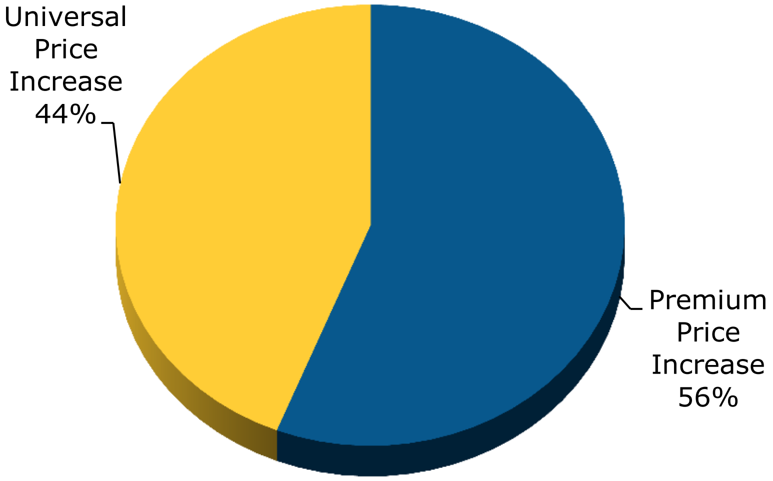


Q: (On a scale of 1 –Not very likely to 10 – Definitely) All things being equal, if FortisBC offered a RNG program?

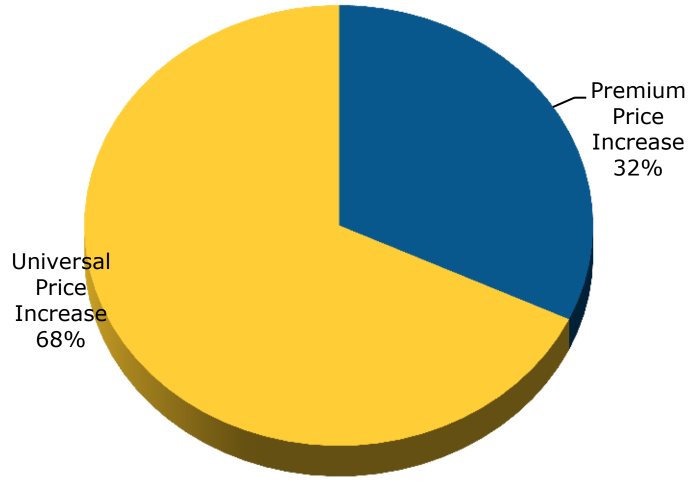
Premiums Versus Universal Pricing Model

Customers were presented with two pricing models: user pay versus a model in which costs are borne by all customers. The greater customer base tends to prefer a user pay model, in which only those who sign up would pay a premium. However, when we filter the results to those interested in participating in the program, the opposite is true. Willing program participants prefer a model in which everybody pays into the program.

All Customers



Those Most Likely to Sign Up



Base: Total customers (n=401)

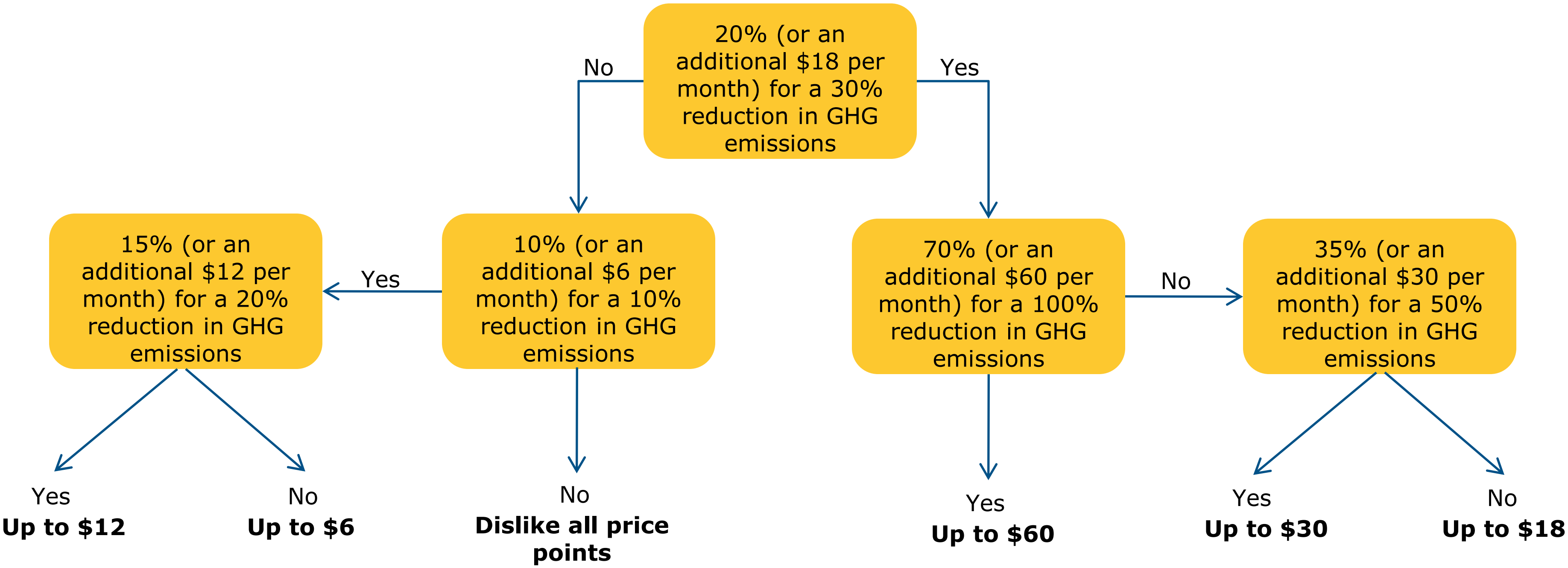
Base: Customers likely to sign up for RNG project (8 or higher out of 10) (n=167)

Q: The costs for a RNG program can be offered to consumers in one of two ways. Which way would you prefer to see FortisBC offer this program.

Price Demand Curves For User Pay RNG Program

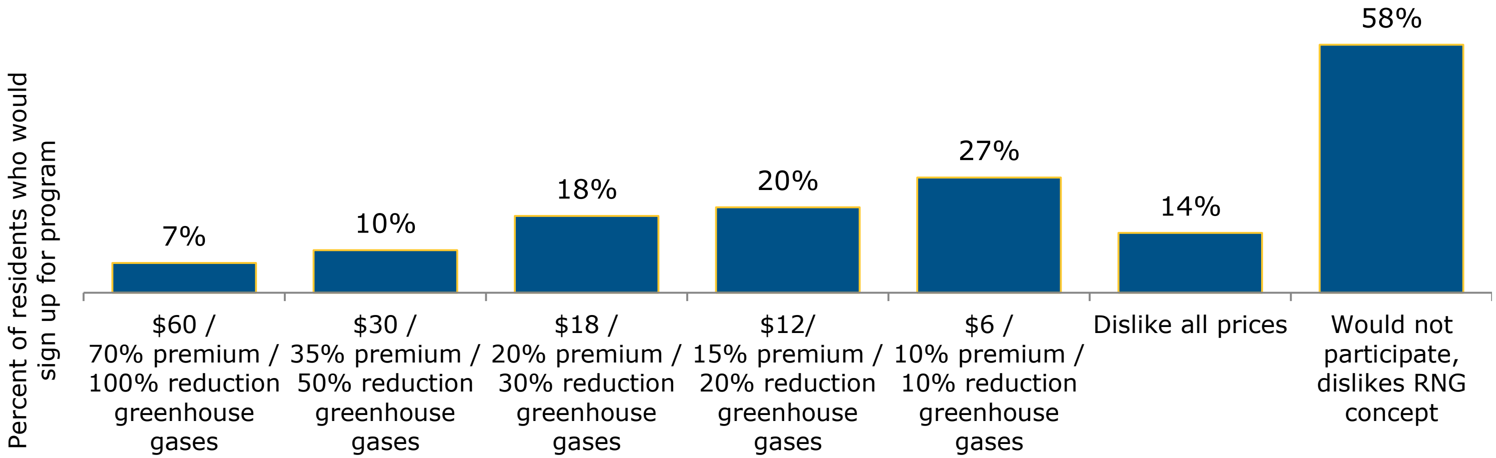
Price is the largest point of contention and barrier for the RNG program. Many customers simply oppose the idea of increases to their gas bill. The key question becomes, what is an acceptable price increase? To answer this question, a price laddering series of questions were asked to understand the price demand curve for FortisBC customers.

For the user pay program respondent were asked if they would sign up if the program was:



Demand Curve for User Pay Pricing Model

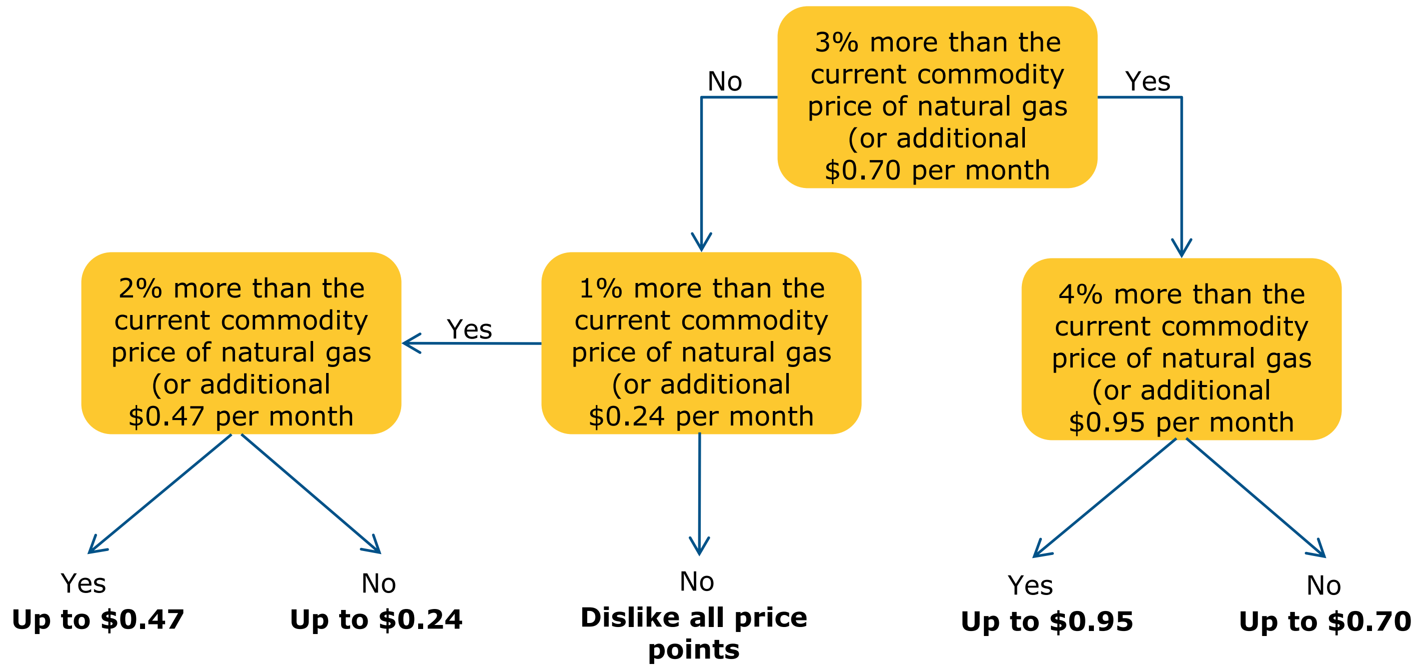
In the user pay model, it is interesting to note that a small proportion of customers (7%) are fully committed to the idea of helping the environment and are prepared to pay a 70% premium on their bill for a fully reduction in their GHG emissions. Up to 27% of customers would sign-up for a program if the price increase involved a lower premium of 10%.



Q18: Suppose FortisBC offered a renewable natural gas program for its customers. Those who sign up would… Would you sign up for such a program?
Q18A: …pay a premium of 10% (or an additional $6 per month) for a 10% reduction in their greenhouse gas emissions.
Q18B: …pay a premium of 15% (or an additional $12 per month) for a 20% reduction in their greenhouse gas emissions.
Q18C: …pay a premium of 20% (or an additional $18 per month) for a 30% reduction in their greenhouse gas emissions.
Q18D: …pay a premium of 35% (or an additional $30 per month) for a 50% reduction in their greenhouse gas emissions.
Q81E: …pay a premium of 70% (or an additional $60 per month) for a 100% reduction in their greenhouse gas emissions.

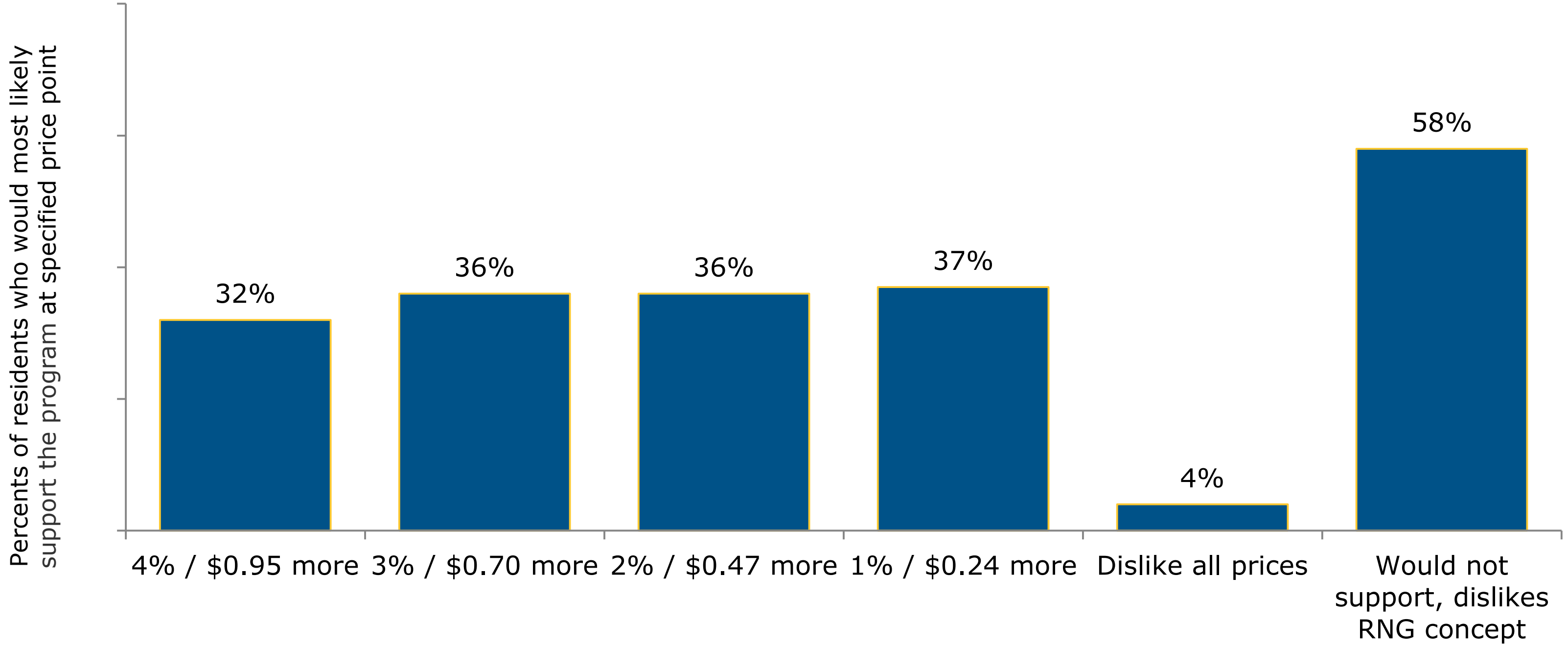
Price Demand Curves For Program Borne By All Customers

To understand the price demand curve for an RNG program borne by all customers, a similar price laddering set of questions were asked. Customers were asked if they would support the program if the program featured:



Demand Curve for Universal Pricing Model

A greater proportion of interested customers are opened to a universal price model borne by all customers. They feel it is fairer that everyone contribute and the lower price points may be more palatable for many of these interested customers.



Q19: In the previous set of questions, customers have the choice of signing up and paying a premium for renewable natural gas. Now suppose FortisBC offered a renewable natural gas program that will be borne by all customers. If the cost of renewable natural gas is borne by all customers and you had to pay 3% more than the current commodity price of natural gas (or an additional $0.70 per month). Would you support such a program?

Q19A; What if the cost of renewable natural gas is borne by all customers and you had to pay 1% more than the current commodity price of natural gas (or an additional $0.24 per month). Would you support such a program?

Q19B: …pay 2% more than the current commodity price of natural gas (or an additional $0.47 per month).

Q19D: …pay 4% more than the current commodity price of natural gas (or an additional $0.95 per month).

Reported Likelihood To Sign Up For Program

From the findings presented in this report, this next section of the report endeavors to estimate the potential market share for a RNG program. The projected market estimates are computed based solely on what respondents tell us in the price curve data presented early. These figures should be considered best case estimates, because the survey environment simulates a perfect market context. It is assumed that:

- 100% of customers are aware and familiar with the program. Presently only 13% of customers are aware and familiar with the RNG program. and,
- Consumers are satisfied by all other program features outside of price and GHG reductions. Presently only 21% of customers like the features of the program, after learning about them.

The reader should also bear in mind two other survey cautions:

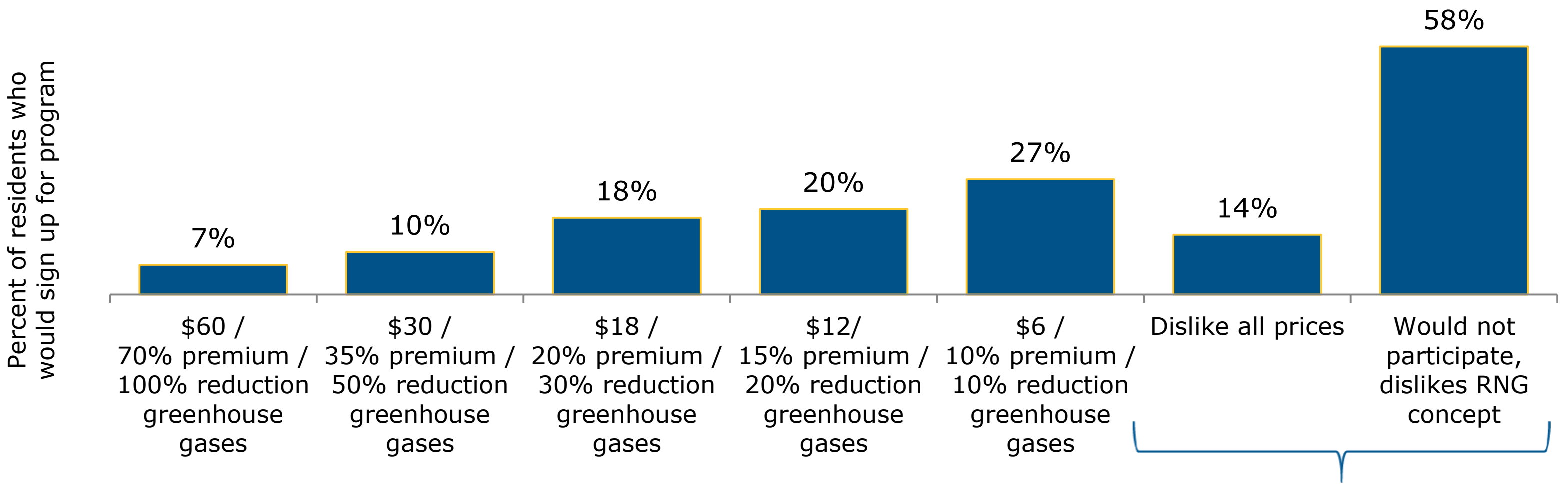
- People do not always do what they say – we often fall short of our intended goals under the best of intentions; and,
- Respondents sometimes have the tendency to provide answers in a manner consistent with how they perceive we want them to answer – in this case, to sign up for a RNG program because it has positive impacts on our environment.

The market projections in this section of the report are based on FortisBC customers who receive a gas bill directly from FortisBC and are responsible for energy decisions in the household.

The reader is also urged to bear in mind that the sampling unit for this study is the household. All projections are made on the basis of residential FortisBC customer households, and not individuals.

Market Potential With User Pay Pricing Model (Best Case Scenario)

In projecting the market potential at various price points, the demand curve figures are converted into estimated number of households that would sign up and into potential revenue projections for FortisBC. At the lower price points FortisBC stands to sign-up a greater number of customers; at the higher price points it stands to potentially garner greater RNG consumption revenues. Once again, the question becomes whether FortisBC prefers to increase the number of participants versus revenues consumption.

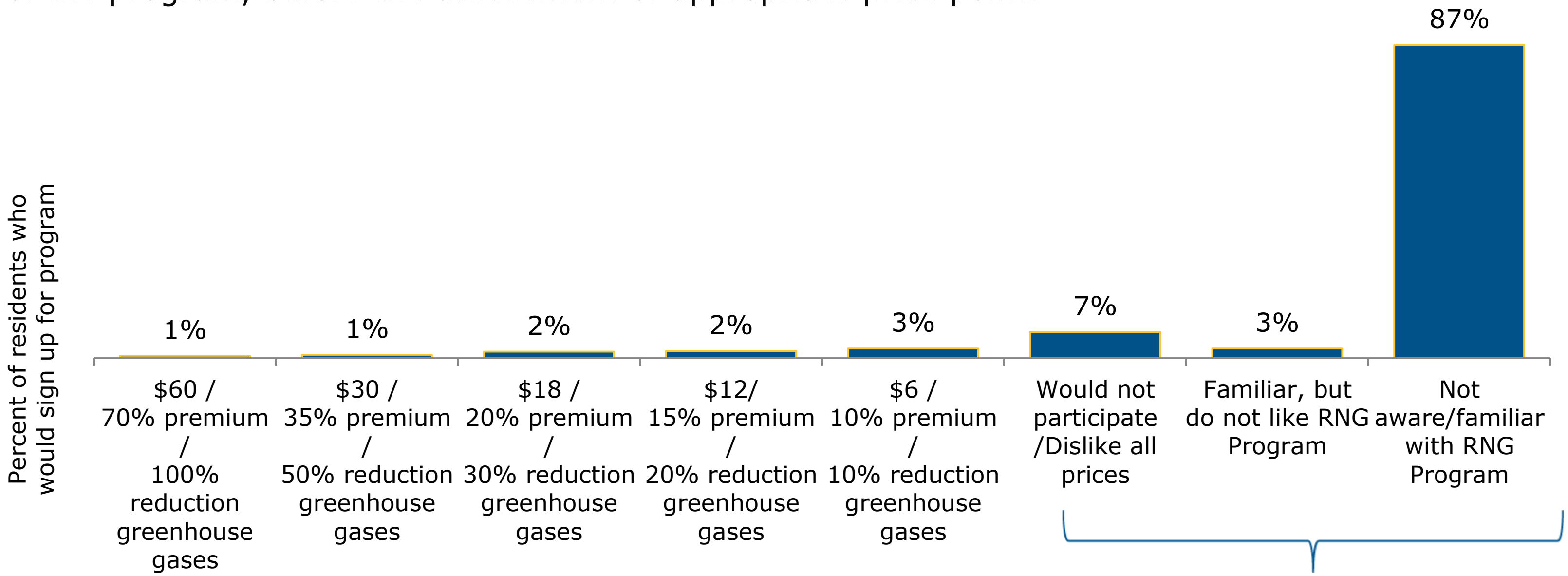


Number of households:	51,796	78,367	140,025	154,552	209,458	554,412

Calculated based on 763,870 FortisBC residential customers in BC Mainland, as per December 2011.

Market Potential With User Pay Pricing Model (Under Current Market Conditions)

If we factor into these estimates, from the main survey, some of the current barriers in terms of lower awareness and dislike for some of the program features, the best case market projections get reduced greatly. In the chart below, we account for the approximately 90% of the market unfamiliar with the program or dislike elements of the program, before the assessment of appropriate price points.



Number of households:	5,347	7,639	13,750	15,277	20,624	743,246

Calculated based on 763,870 FortisBC residential customers in BC Mainland, as per October 2012.

Appendix To The Methodology

Appendix To The Methodology (1)

Overview

A total of 401 online interviews was conducted on the week of October 29, 2012 with a sample of FortisBC mainland customers. Respondents were screened on a number of different criteria. To qualify for this study, the household must be a customer of FortisBC and must received their energy bill directly from the utility. Households currently participating in the FortisBC RNG program were disqualified from this survey (none were disqualified on this basis). Furthermore, the respondent completing the survey must be one of the members of the household responsible for making energy decisions.

Sample Frame And Design

The random sample used in this survey was drawn from the Asking Canadian's online adult panel. All BC communities were sampled and screened as described above. The results of this study were weighted by region (70% Lower Mainland and 30% BC Interior) to reflect the size of the FortisBC residential customer base.

Questionnaire Development

The questionnaire was developed by TNS Canadian Facts in consultation with FortisBC.

Data Collection

Respondents were recruited from the Asking Canadians' online panel and directed to their survey site to complete the survey.

Appendix To The Methodology (2)

Survey Margin of Error

The reader is cautioned that the survey results are subject to margins of error. The overall sampling error for 401 total interviews at the 90% confidence level is approximately ± 4.1%. For example, if 50% of all respondents surveyed stated that they would sign-up to the RNG program, then we can be sure, nine times out of ten, that if the entire population had been interviewed, the proportion would lie between 45.9% and 54.9%.

When a segment of the entire data is analyzed, the sampling error increases. For example, the overall sampling error for data based on 169 interviews at the 90% confidence level is approximately ± 6.4%. In this case, using the scenario where respondents surveyed state that they would sign up for the RNG program, then we can be sure, nine times out of ten, that this proportion would lie between 43.6% and 56.4%.

A copy of the questionnaire used in this survey are appended to this report.

TNS

FORTIS BC™

Appendix B

UTILITY GREEN POWER MARKET RESEARCH

Utility Green Power Reseach Findings

Assumptions
* Based on residential programs only
* All prices in US$ except FortisBC prices
* All energy units in GJ's

Key
* Prog Type B = block/ % = blend options/ 100% = 100% volumetric option

Interviews Conducted March - April 2015, by Janelle De La Cour and Neil Dobson

Company	Gas or Electric	Program Type	Interview conducted?	Base Price per GJ	Green Energy Price per GJ	$ Premium per GJ	% Premium	Monthly premium for Avg house at 100% green power	% Residential Participation (Ranking)	% of Green Energy as a % of Total Energy Sold (Ranking)
FortisBC Rate 1 (LML service area)	G	%	n/a	$7.38	$19.30	$ 10.43 (w/ tax credit)	400%	$72	0.7%	0.001%
Wellesley Municipal Light Plant	E	%	Y			$11.11	25%		11% (3)	11% (2)
Madison Gas & Electric	E	%	Y	Summer - $29.74; Winter - $26.61		$6.78		$20-30	8% (8)	
Puget Sound Energy (Electrical)	E	B & 100%	Y	First 2.16 GJe at $25.58 per GJ; then $30.81	$34.72 per GJ or $4 per block. Avg 2 blocks/month ~ 100% "green"	$3.47		$10-12	6.3%	
Puget Sound Energy (Gas)	G	B			$4 per block. Average customer needs 2 blocks per month to be 100% green energy			$8	0.2%	
North West Natural	G	100%	Y	$4.11		$0.99	25%	$5.50	4.0%	
North West Natural	G	B		$4.11	$5.50 per block. For the average user this equates to 100% green energy					
River Falls Municipal Utilities	E	B	Y	27.14	$3 per block of 1.08GJe	$2.78		$5.50	5.8% (10)	8.1% (5)
Portland General Electric (Green Source)	E	100%	Y	3.6Gje at $0.065 per GJ then at $0.0722 per kWh		$2.22	6%	$7-10	15% (1)	8.9% (4)
Portland General Electric (Clean Wind)	E	B		First 3.6Gje at $18.06 per GJ then at $20.06	$2.50 per block of 0.72 Gje					
WPPI	E	B	Y		$3 per block of 1.08GJe	$2.78				
Green Mountain Power	E	%	Y	$38.94		$11.11	29%	$20	1.5%	
City of Palo Alto	G	100%	N	$0.95 - $18.95		$1.14		$5	19.4% (1)	3.2% (10)
Washington Gas Energy Services	G	100%	N	$3.89		$1.42				
Pacificorp California	E	B	N	$41.61		$5.41				
Pacificorp Oregon	E	B & 100%	N	Tier 1 $27.71 and Tier 2 $32.19		$2.92			8.9% (6)	
City of Naperville (IL)	E	B	N	$27.89	$5 per block of 0.72GJe	$6.94		$20-25	6.2% (9)	
Sacremento Municipal Utility District	E	100%	N	variable	$3 (50%) or $6 (100%) monthly flat fee			$6	11.7% (2)	4.3% (9)
Silicon Valley Power	E	100%	N	Tier 1 at $27.19 per GJe Tier 2 at $31.25 per GJe		$4.12		$7.50	8.1% (7)	5.3% (6)
National Grid - Ma	E	%	N	$38.89		$6.69 to $10.56				
Lake Mills Light & Water	E	B	N	$34.58	$3 per block of 1.08 GJe			$6		
Farmers Electric Cooperative of Kalona	E	B	N	Summer: first 2.88GJ at $34.72 per GJe $31.94. Winter - $22.92	Minimum of $3 per month				10.4% (4)	
Xcel Energy - Co	E	B	N	1.78GJ at $12.78 per GJe; then $25. Winter - $12.78	$2.16 for a 0.36 GJ block	$6				

Utility Interview Questions – FEI Spring 2015

To understand voluntary participation in "green energy" offerings

	Program design	
1	When did the program start?	
2	How is the program structured? Did you consider different options?	
3	How would you describe the framing or positioning of the product? (Are you selling energy, carbon savings or the investment into sustainable energy projects?)	
4	Do/did you have an external partner or a relationship with a third party in program design, implementation or marketing?	
5	Are there any competing programs in your jurisdiction from other renewable energy providers?	
	Program Participation	
6	How many customers currently participate?	
7	Who are the customers? Residential? Commercial? Do you have any customer segmentation information (demographic / geographical) you could share with me?	
8	Do you have any insight into customer's motivations for signing up – both residential and commercial customers?	
9	Was program growth linear or has it fluctuated? If it fluctuated do you know why? Have you done anything differently from a program design/ price/ promotional perspective that could explain these fluctuations?	
10	What is the churn rate? Is this different to your churn rate for your standard offering?	
	Program Pricing	
11	What is the premium your customers pay over and above your standard offering?	
12	What costs are built into this price? Does it include the full costs of having and running the program or does your regulator allow you to spread some costs across non-participant customers? If some costs are being recouped from all customers what are these costs and what % of total program costs does this relate to?	
13	Was pricing/ program design driven by the desire to maximize participation or maximize revenue?	
14	What if any research did you do to determine price? Has this research been proven correct with the actual take up of the program?	
	Program Promotion	
15	What are your primary marketing channels?	
16	Is there one channel that works best?	
17	Is there a key message that resonated well with your customer?	
	Summary Question	
18	In your opinion, which component – program design, price or promotion is the key element in the success of the program?	

Appendix C

U.S. NREL MARKET STUDY REPORT 2013

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Status and Trends in the U.S. Voluntary Green Power Market (2013 Data)

Jenny Heeter
National Renewable Energy Laboratory

With contributions from:

Kathy Belyeu
Independent Consultant

Ksenia Kuskova-Burns
National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Technical Report
NREL/TP-6A20-63052
November 2014

Contract No. DE-AC36-08GO28308

NATIONAL RENEWABLE ENERGY LABORATORY

Status and Trends in the U.S. Voluntary Green Power Market (2013 Data)

Jenny Heeter
National Renewable Energy Laboratory

With contributions from:

Kathy Belyeu
Independent Consultant

Ksenia Kuskova-Burns
National Renewable Energy Laboratory

Prepared under Task No. SA12.0324

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

Technical Report
NREL/TP-6A20-63052
November 2014

Contract No. DE-AC36-08GO28308

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Available electronically at http://www.osti.gov/scitech

Available for a processing fee to U.S. Department of Energy and its contractors, in paper, from:

U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
phone: 865.576.8401
fax: 865.576.5728
email: mailto:reports@adonis.osti.gov

Available for sale to the public, in paper, from:

U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
phone: 800.553.6847
fax: 703.605.6900
email: orders@ntis.fedworld.gov
online ordering: http://www.ntis.gov/help/ordermethods.aspx

Cover Photos: (left to right) photo by Pat Corkery, NREL 16416, photo from SunEdison, NREL 17423, photo by Pat Corkery, NREL 16560, photo by Dennis Schroeder, NREL 17613, photo by Dean Armstrong, NREL 17436, photo by Pat Corkery, NREL 17721.

NREL prints on paper that contains recycled content.

Acknowledgments

This work was funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy. The authors thank the Strategic Programs Office for its support of this work. For their thoughtful review of the document, the authors thank Stephen Capanna, U.S. Department of Energy; Kevin DeGroat, ANTARES Group; Joyce Dickerson, Google; Gary Fogelman, Good Energy; Ed Holt, Ed Holt and Associates; Ian McGowan, 3Degrees; Kevin Taylor, WWF; and Lori Bird, Jaquelin Cochran, Jeff Logan, and David Mooney of the National Renewable Energy Laboratory (NREL) as well as Karin Haas and Kendra Palmer of NREL for editorial support. The authors thank Viggo Fish of NREL for assistance gathering data from green power marketers. The authors also thank Austin Brown and Bethany Gorham for data on the information and communications technology sector. Finally, the authors thank the many green power marketers and utility contacts who provided the information summarized in this report.

Additional information on green power market trends and activities can be found on the Department of Energy's Green Power Network website at greenpower.energy.gov.

List of Acronyms

CCA	community choice aggregation
DG	distributed generation
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
GHG	greenhouse gas
ICT	information and communication technologies
IOU	investor-owned utility
kW	kilowatt
kWh	kilowatt-hour
M-RETS	Midwest Renewable Energy Tracking System
MW	megawatt
MWh	megawatt-hour
NC-RETS	North Carolina Renewable Energy Tracking System
NREL	National Renewable Energy Laboratory
PJM-GATS	PJM-Generation Attribute Tracking System
PPA	power purchase agreement
PV	photovoltaic
PUC	public utility commission
REC	renewable energy certificate
RPS	renewable portfolio standard
SREC	solar renewable energy certificate
TVA	Tennessee Valley Authority
WREGIS	Western Renewable Energy Generation Information System

Executive Summary

The "voluntary" or "green power" market is that in which consumers and institutions voluntarily purchase renewable energy to match all or part of their electricity needs. Voluntary action provides a revenue stream for renewable energy projects and raises consumer awareness of the benefits of renewable energy. There are numerous ways consumers and institutions can purchase renewable energy. Historically, the voluntary market has consisted of three market sectors: (1) utility green pricing programs (in states with regulated electricity markets), (2) competitive suppliers (in states with restructured electricity markets), and (3) unbundled renewable electricity certificate (REC) markets, where RECs are purchased by consumers separately from electricity ("unbundled"). This analysis, for the first year, also includes an assessment of an emerging sector, (4) community choice aggregation (CCA). CCAs allow communities to collectively choose the source of their electricity generation while maintaining transmission and distribution service from their existing provider. Many CCAs are sourcing significant amounts of renewable energy.

The voluntary market continued to exhibit growth and stimulate renewable energy development in 2013. Interest in products that have direct impact on renewable energy development is increasing. Utilities have begun offering programs for large industrial customers and are incorporating more local solar resources into their product mixes. CCAs are examining ways to buy local renewable resources. Large corporate purchasers in the internet and communications technology (ICT) sector are turning towards direct investment, long-term contracting, and other mechanisms to spur voluntary renewable energy development and/or realize financial gain. These customers are unique in that they have large, stable, long-term electricity load; they are purchasing in states with restructured electricity markets where there are opportunities for financial benefit. Based on our review of the voluntary market, we identified the following market trends:

- In 2013, voluntary retail sales of renewable energy totaled 62 million megawatt-hours (MWh) and represented approximately 1.7% of total U.S. electricity sales (Figure ES-1). From 2012 to 2013, total green power market sales increased 27%.[1]

[1] In this report, we gathered data and estimated the size of the CCA market for the first time. Because we include this market in the total sales figures for 2013 but not for 2012, some of sales growth from 2012 to 2013 is overestimated.

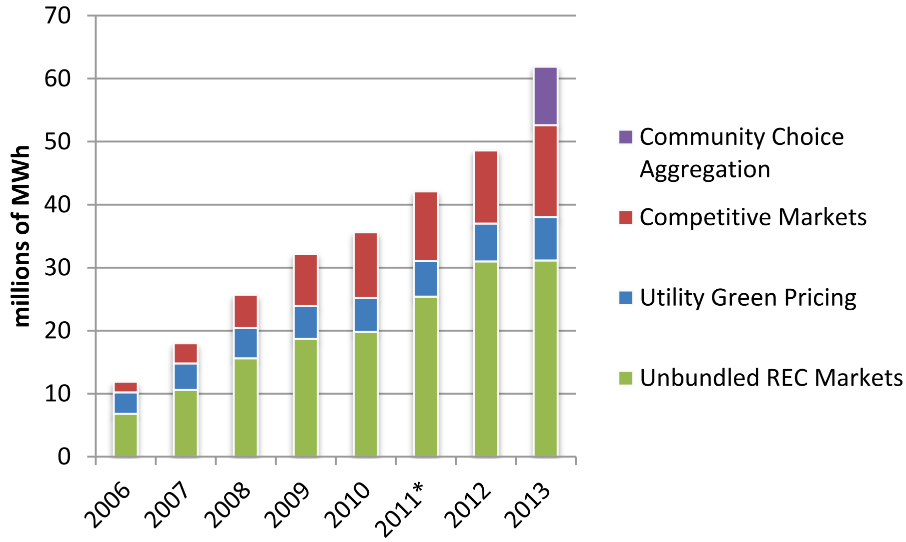


Figure ES-1. Estimated annual voluntary sales by market sector, 2006–2013

* Voluntary sales for 2011 are estimated as the mid-point of 2010 and 2012 sales.

- Approximately 5.4 million customers are purchasing green power. The number of customers in utility green pricing programs and the competitive market increased by 25% and 87%, respectively, while declining by 14% in the unbundled REC market. Residential REC market customers declined more than 20%, while nonresidential REC market customers increased by 4%.
- For 2013, we found approximately 2.4 million customers participating in CCAs that source renewable energy, totaling more than 9 million MWh of renewable energy.
- Utility green pricing sales exhibited strong growth of 15% in 2013, primarily due to sales increases in some of the largest programs.
- Competitive markets grew to 14.5 million MWh, a 25% increase from 2012, due in part to increased data availability. More competitive suppliers are reporting to Energy Information Association (EIA) through the Form 861.
- Unbundled REC markets saw little movement in 2013, increasing just 1%, to 31.4 million MWh. Increases in wholesale REC market prices and interest by large customers in procuring renewable energy in more direct ways may be causing the lack of aggressive growth seen in previous years.
- Wind energy continues to provide the most renewable energy to the voluntary market, at 75% of total green power sales, followed by landfill gas and biomass (7%), hydropower (4%), solar (1%), and geothermal (1%). The source for 12% of supply is unknown, though is likely mostly wind. Of the voluntary market sectors, green pricing programs are using the most solar; the percent solar used in green pricing programs increased from 2.0% in 2012 to 2.5% in 2013.

- The number of community solar programs is increasing. Community solar programs allow participants to purchase a portion of a larger solar array, and then receive the financial benefits of that investment, typically in the form of bill credits. In 2013, 15 new community solar projects were introduced, and as of September 2014, an additional 14 programs had begun. The capacity of existing community solar projects totals more than 40 MW, with an additional 17 MW of projects under development. The RECs from these projects are typically used to meet RPS compliance, and therefore, are not included in Figure ES-1.
- Wholesale RECs used in the voluntary market traded at around $1.20/MWh in 2013, up from less than $1.00 in previous years. Pricing is for nationally sourced projects; pricing differs by technology, region, and purchase size. The increased pricing may have contributed to the flat growth in the unbundled REC market in 2013.

Table of Contents

List of Figures

List of Tables

1 Introduction

"Voluntary" markets for renewable energy, or "green power" markets, are those in which consumers and institutions voluntarily purchase renewable energy to match their electricity needs. These purchases are in addition to renewable energy that is used to fulfill renewable portfolio standards (RPS). Traditionally, entities purchased renewable energy through utility green power programs, green power marketing activities in competitive electricity markets, or in unbundled REC markets. Emerging methods of voluntary procurement are providing customers with new ways to support renewable energy. In some cases, new models are providing a hedge against future electricity price increases or other benefits, but they do not provide the environmental benefit to the customer (i.e., the REC is transferred to another party). All of these approaches are covered in this report:

- **Utility green pricing (regulated utility markets).** Utility green pricing programs began in the early 1990s when a few utilities offered options to their customers. These programs continue to be offered by utilities in traditionally regulated electricity markets. In utility green pricing programs, RECs are obtained by the utility and offered to customers. Utilities differ in how they procure RECs for their green pricing programs but often enter into power purchase agreements for the energy and RECs. In other cases, they may procure unbundled RECs.
- **Competitive suppliers (competitive utility markets).** In states with competitive (or restructured) retail electricity markets, electricity customers can often buy electricity generated from renewable sources by switching to an alternative electricity supplier that offers green power. In some of these states, default utility electricity suppliers offer green power options to their customers in conjunction with competitive green power marketers so that switching is not required. More than a dozen states that have opened their markets to retail competition have experienced some green power marketing activity.[2]
- **Voluntary unbundled REC market (separate from electricity).** Whether or not customers have access to a green power product from their retail power provider, they can purchase green power through unbundled RECs. More than 60 companies offer unbundled RECs to retail customers via the Internet, and a number of other companies market RECs solely to commercial and wholesale customers.

---

[2] States with competitive offerings include Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, and Texas. Washington, D.C. also has green power marketing activity.

- **Community choice aggregation (CCA).** Authorized in six states, CCAs allow communities to determine their electricity generation sources by aggregating the community load and purchasing electricity from an alternate electricity supplier while still receiving transmission and distribution service from their existing provider. CCAs are sometimes described as a hybrid between services offered exclusively by investor-owned utilities (IOUs) and municipal utilities. CCAs are typically opt-out programs, meaning that customers must take action to opt-out, whereas green pricing programs are opt-in programs, requiring customers to take action to subscribe. This distinction leads to much higher enrollment rates for CCAs compared to green pricing programs.

  We tracked CCA renewable purchases for the first time in this report. We found that CCAs are purchasing more than 9 million MWh of renewable energy – making the sector larger than the utility green pricing sector. Although most of the supply for CCAs is coming from competitive suppliers, we separate the figures in this report to show the relative size of each.

- **Community solar.** Community solar programs allow utility customers to purchase a portion of a larger solar project. Customers then receive the benefits of the energy that is produced by their share. Structures differ, but a common model is for the RECs to be transferred to the utility to meet compliance with an RPS. As of September 2014, 64 community solar projects totaling more than 40 MW exist in the United States.

- **Large direct project investment and "crowdfunding."** Large organizations have made direct investments in renewable projects. For example, Google's investments have supported more than 2,500 MW of wind and solar in the United States. On a smaller scale, crowdfunding, which allows individuals to contribute to project financing, has supported solar development. For example, Mosaic, a crowdfunding platform for solar, has invested in more than 30 MW of solar. Project investments, whether large or small, typically do not convey the RECs to the investors. Investors also do not receive the power produced by the project.

- **Direct power purchase agreements and large commercial customer green power rates.** A number of corporations, universities, and others have negotiated power purchase agreements for renewable energy. Importantly, not all states allow for power purchase agreements. PPAs are more commonly allowed in states with restructured electricity markets. A few utilities now have new tariffs that allow large utility customers to purchase renewable energy from a specific facility in the utility service territory, instead of negotiating a power purchase agreement directly.

- **On-site solar/solar leasing.** On-site solar systems, which in some states are primarily owned by third parties, allow customers to provide a location for a solar system and potentially see savings on electricity expenditures. In most cases outside of California, the RECs from on-site solar systems are sold to a utility to use for RPS compliance, sometimes in exchange for an incentive.

Table 1 outlines these emerging models and highlights the relative market sizes compared to utility green power, competitive suppliers, and unbundled RECs. While the emerging methods have seen large growth in recent years, the capacity they support as of 2013 was much less than is supported by utility green pricing, competitive suppliers, and the unbundled REC market. In some cases, markets do overlap, making it difficult to compare true market sizes.

Table 1. Comparison of Voluntary Support Mechanisms

Support Mechanism	REC Ownership	Value Proposition	Market Size
Utility green power or competitive supplier	With customer	Match part or all of electricity use with renewables; corporate sustainability goals	8,700 MW
Unbundled RECs	With customer	Match part or all of electricity use with renewables; corporate sustainability goals	11,300 MW
On-site photovoltaics (PV)	Outside of California, typically sold to utility or exchanged for incentive payment	Support renewables development by providing a host site; potentially lower electricity bill through use of net metering	2,218 MW residential, 4,044 MW nonresidential[a]
CCA	Typically with consumer	Match part or all of electricity with renewables; meet municipal greenhouse gas (GHG) reduction or renewable energy targets	4,100 MW
Community solar	Varies, currently almost always sold to utility or exchanged for incentive payment	Support local solar development; potentially lower electricity bill	40 MW (September 2014)
Power purchase agreements/ large commercial customer green power rates	Varies	Corporate sustainability goals; support new renewables; potential price hedge	Unknown; 2.3 million MWh under long-term contract by EPA Green Power Partners as of January 2014
Direct project investment	Typically with project developer	Support new renewables; potential financial return	Aggregate unknown; 2,500 MW by Google[b]
Crowdfunding	Varies	Support new solar development; potential financial return	Aggregate unknown; 33 MW by Mosaic[c]

[a] SEIA and GTM (2014)
[b] As of May 2014 (Google 2014).
[c] As of May 2014 (Mosaic 2014).

The voluntary market continues to play a large role in the overall renewable energy market. Figure 1 estimates market sizes by showing the total non-hydropower renewable generation in the U.S. (EIA 2014), split into voluntary, compliance, and "other renewables"; "Other renewables" include renewable energy procured on a least-cost basis or by utilities that are not subject to an RPS and are not using the RECs to supply a voluntary program. This figure is only an estimate as some hydropower is used in compliance and voluntary markets. This figure will evolve over time; by 2015, compliance demand for new renewable energy due to existing state RPS policies is expected to be about 140 million MWh (Heeter 2013).[3]

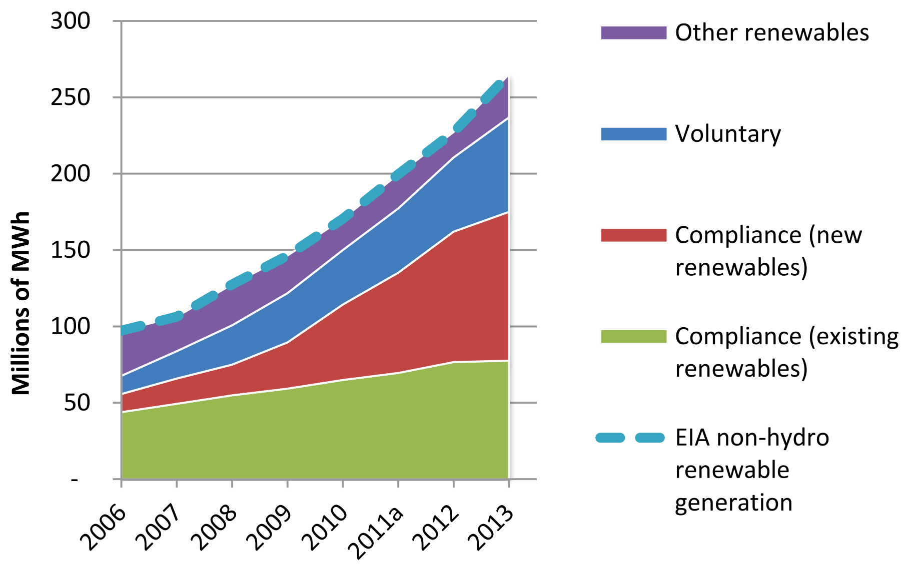


Figure 1. Comparison of renewable energy estimated market sizes, 2006–2013

Sources: Heeter (2013); EIA (2014a)

[a] Voluntary sales for 2011 are estimated as the mid-point of 2010 and 2012 sales.
Estimates of compliance market demand assume that RPS targets are fully met. Solar generation assumes a 25% capacity factor for CSP and an 18% capacity factor for PV.

The data on voluntary market trends presented in this report were formerly reported in *Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2012 Data)* (Heeter and Nicholas 2013), *Market Brief: Status of the Voluntary Renewable Energy Certificate Market (2011 Data)* (Heeter et al. 2012), and *Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data)* (Heeter and Bird 2011).[4]

[3] Although RPS policies generally allow pre-existing renewable energy generation sources (i.e., those installed *before* the adoption of the RPS) to meet their targets, the estimates presented here reflect only the amount of new renewable energy generation that these policies are expected to stimulate. These figures are compared to the voluntary market estimates because the voluntary market primarily supports generation from new renewable energy projects (i.e., those installed *after* voluntary green power markets were established). Estimates of compliance market demand assume that RPS targets are fully met.
[4] Voluntary market data from previous years are captured in earlier versions of this report, including Heeter et al. (2012), Heeter and Bird (2011), Bird and Sumner (2010), Bird et al. (2009), and Bird et al. (2008).

Voluntary market data are based on figures provided to the National Renewable Energy Laboratory (NREL) by utilities and independent renewable energy marketers. NREL also supplements this data with information from EIA, REC certifiers, REC tracking systems, and press releases describing large voluntary green power purchases. Because data cannot be obtained from all market participants, the estimates presented here likely underestimate the market size. Because obtaining data on competitive markets is particularly challenging due to market sensitivity and rapid changes in offerings, estimates of the competitive market are more uncertain.

This report presents data and analysis on voluntary market sales and customer participation, products and premiums, green pricing marketing, and administrative expenses. The report also details trends in REC tracking systems, REC pricing in voluntary and compliance markets, community and crowd-funded solar, and interest in renewable energy by the ICT sector.

2 Voluntary Green Power Market

Voluntary consumer purchases of renewable energy represent a market support mechanism for renewable energy development. In the early 1990s, a small number of U.S. utilities began offering "green power" options to their customers. Since then, these products have become more prevalent, offered by traditional utilities and renewable energy marketers operating in states that have introduced competition into their retail electricity markets or offering RECs online. Today, more than half of all U.S. electricity customers have an option to purchase some type of green power product directly from a retail electricity provider, while all consumers have the option to purchase RECs.

2.1 Voluntary Market Sales

Overall, retail sales of renewable energy in voluntary green power markets totaled nearly 62 million MWh and represented approximately 1.7% of total U.S. electricity sales in 2013.[5]

Green power sales (in megawatt-hours) increased by 27% between 2012 and 2013, or 8% when CCAs are not included (see Table 2 and Figure 2). Because we began estimating CCA sales in 2013, no prior market estimate is available. The unbundled REC market accounted for half of all green power sales, less than in previous years, and the competitive market sector is increasing its share. While we show the competitive market at 14.5 million MWh, much of the CCA supply (9.3 million MWh) also comes from competitive suppliers.[6]

Text Box 1 highlights purchasing by federal agencies, which has also increased in recent years, and will continue to increase through 2020.

[5] U.S. electricity sales totaled 3,692 million MWh in 2013 (EIA 2014b).

[6] The REC sales figures reflect sales to end-use customers separate from electricity. RECs bundled with electricity and sold to end-use customers through utility green pricing programs or in competitive electricity markets are counted in other categories.

Table 2. Estimated Annual Voluntary Sales (Millions of MWh) by Market Sector, 2006–2013[a]

Market Sector	2006	2007	2008	2009	2010	2012	2013
Utility Green Pricing	**3.4**	**4.2**	**4.8**	**5.2**	**5.4**	**6.0**	**6.9**
% Change from previous year	39%	23%	15%	7%	5%	5%[f]	15%
Competitive Markets	**1.7[b]**	**3.2**	**5.3[c]**	**8.3[c]**	**10.4**	**11.6**	**14.5**
% Change from previous year	-20%[d]	88%	64%[c]	56%[c]	25%	6%[f]	25%
CCA			**Not estimated**				**9.3**
Unbundled REC Markets[e]	**6.8**	**10.6**	**15.6**	**18.7**	**19.8**	**31.0**	**31.4**
% Change from previous year	75%	55%	49%	20%	6%	25%[f]	1%
Retail Total	**11.9**	**18.0**	**25.7[c]**	**32.2[c]**	**35.6**	**48.6**	**61.9**
% Change from previous year	40%	51%	43%[c]	25%[c]	11%	17%[f]	27%

[a] Includes sales of new and existing renewable energy; totals and growth rates may not compute due to rounding.

[b] Sales figures for 2006 may be underestimated because of data gaps.

[c] Competitive market sales for 2008 and 2009 were revised upward in this report to reflect data on green power markets in Texas published by the Texas public utility commission (PUC) in 2010 and 2011. For historical reports, see https://www.texasrenewables.com/reports.asp (Accessed October 14, 2013.)

[d] 2006 number is likely underestimated because of data gaps.

[e] Includes only RECs sold to end-use customers separate from electricity (unbundled).

[f] Compound annual growth rate for 2010–2012; changes from 2010 to 2012 were 11% for utility green pricing, 12% for competitive markets, 56% for unbundled REC markets, and 37% total.

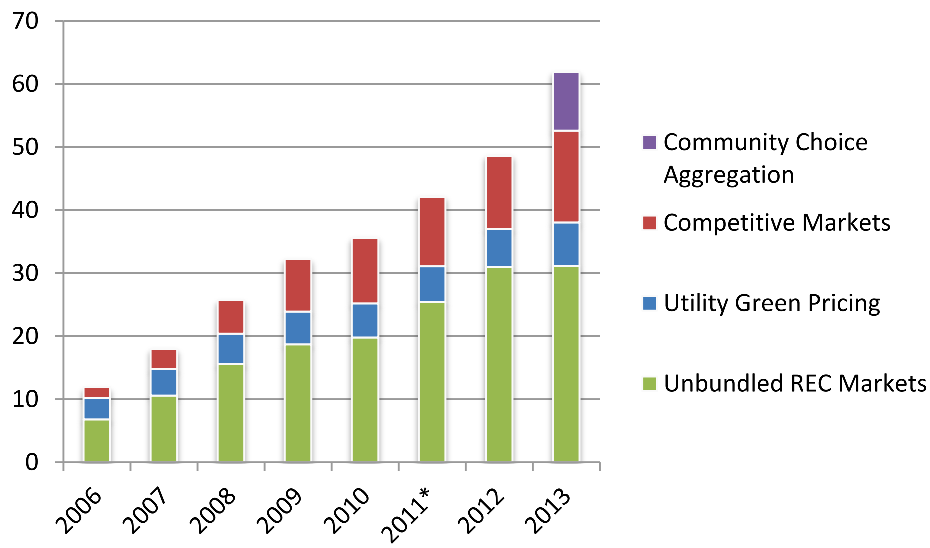


Figure 2. Estimated annual voluntary sales by market sector, 2006–2013

* Voluntary sales for 2011 are estimated as the mid-point of 2010 and 2012 sales.

Text Box 1. Federal sector renewable energy purchasing

The federal government is a large and growing purchaser of renewable energy. The Energy Policy Act of 2005 required that the federal agencies purchase 7.5% of their facility energy from renewable sources in 2013. By 2020, agencies are required – to the extent economically feasible and technical practicable – to use renewable energy equal to 20%, as directed by the December 5, 2013 Presidential Memorandum on Federal Leadership in Energy Management. The Department of Defense has a goal to develop 3 GW of renewable energy on Army, Navy, and Air Force installations by 2025.

In fiscal year 2013, agencies purchased 3.4 million MWh of “new” renewable energy, and 0.6 million MWh of “old” renewable energy, for total use of 4.1 million MWh, or 7.4% of facility energy use (DOE 2014). Federal policy allows for bonuses for renewable energy on federal or Indian land; when those bonuses are included, the percentage increases to 9.2%.

Of the renewable energy purchased by federal agencies (not including on-site generation), wood and wood residuals make up half, followed by wind (27%). Hydropower makes up 10% (conventional 7% and incremental 3%), followed by biogas (6%), municipal solid waste (3%), and solar PV (1%). Conventional hydropower is reported but does not count towards renewable requirements.

Federal government purchases (outside of on-site generation) are primarily through RECs (86%), though some renewable energy is being purchased through utility programs or other bundled contracts (14%).

In terms of resources used, wind energy represented 75% of 2013 total green power sales, followed by biomass energy sources, including landfill gas (7%), hydropower (primarily low impact or small hydropower, 4%), solar (1%), and geothermal (1%) (Figure 3). Of the voluntary market sectors, green pricing programs are using the most solar; the percent solar used in green pricing programs increased from 2.0% in 2012 to 2.5% in 2013.

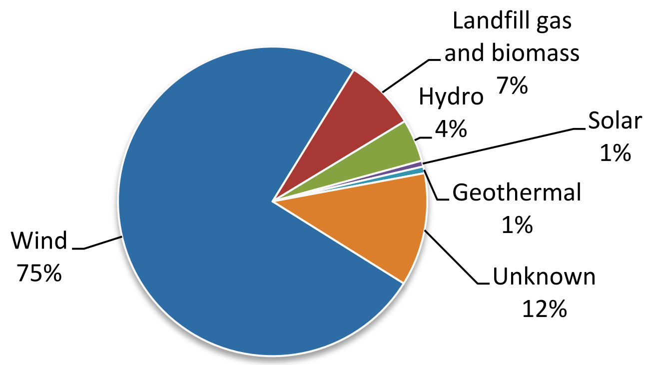


Figure 3. Estimated green power sales by renewable energy source, 2013

2.1.1 Utility Green Pricing Sales

Utility green pricing sales rebounded strongly in 2013, driven by large gains in some of the largest green pricing programs. Portland General Electric, Austin Energy, and CPS Energy increased green power sales by 18%, 16%, and 14%, respectively.

Collectively, utilities in regulated electricity markets sold about 6.9 million MWh of green power to customers in 2013 (Table 2). Green pricing program sales to all customer classes grew by a compound annual growth rate of 15% between 2012 and 2013, exhibiting growth similar to that in 2008 and prior years (Table 2). While some programs continue to grow robustly, growth in this sector is quite uneven, with some programs seeing large gains and others seeing declining sales.

In utility green pricing programs, the average residential purchase in 2013—approximately 5,400 kilowatt-hours per year (kWh/year)—was slightly lower than that in 2012 (5,800 kWh/year) but consistent with 2008 (approximately 5,500 kWh/year). The average nonresidential purchase increased about 9% in 2013, to about 248,000 kWh/year, after increasing nearly 60% between 2010 and 2012. Purchasing by the University of Tennessee, Knoxville in Tennessee Valley Authority's (TVA) green pricing program drove that utility's average nonresidential purchase rate up dramatically from the national average. The University of Tennessee, Knoxville is ranked 68th on the Environmental Protection Agency's (EPA) Green Power Partnership (GPP) top partner list, purchasing more than 80,000 MWh from TVA and through on-site generation.

In 2013, green pricing sales represented a small proportion of a utility company's overall energy sales. On average, renewable energy sold through green pricing programs in 2013 represented 1.3% of total utility electricity sales of the utilities offering green pricing programs (on a megawatt-hour basis). Top performing programs saw rates ranging from 3.3% to 23.8%. Due to a large nonresidential purchase, one small utility reported that 23.8% of its total retail electricity sales were green power sales.

In 2013, utility green power supply typically came from within a utility's broader region (93%) (Table 3).[7] Nearly a quarter of utility green power supply came from within the utility's service territory.

When examining the type of procurement, unbundled RECs account for more than half (55%) of utility green pricing supply, followed by bundled RECs (36%). While unbundled RECs are typically procured through contracts of five years or less, the vast majority of bundled RECs (95%) are procured through contracts of 11+ years. Smaller portions of utility green power supply came from systems owned by the utility (7%) or was purchased from utility customers (e.g., from on-site solar systems) (2%). These trends are consistent with those reported for 2012.

Table 3. Location of Utility Green Power Supply, 2013

Within Service Territory	Within State	Within Region[7]
24%	61%	93%

Table 4. Contract Length by Type of Utility Green Power Procurement, 2013

Contract Length	Unbundled RECs	RECs Bundled with Electricity	Projects Owned by Utility	RECs Produced by Utility Consumers
≤1 year	46%	0%	0%	0%
2–5 years	52%	0%	0%	19%
6–10 years	2%	5%	0.02%	4%
≥11 years	0%	95%	99.98%	77%
Percent of total procurement	55%	36%	7%	2%

2.1.2 REC and Competitive Market Sales

In REC markets and competitive green power markets (i.e., in states with retail competition), an estimated 45.9 million MWh of renewable energy was sold to retail customers in 2013 (Table 2). Overall, 2013 saw large gains in competitive electricity markets but nearly flat growth in the unbundled REC market.

In competitive electricity markets, an estimated 14.5 million MWh were sold as a bundled green power product in competitive electricity markets—a 25% increase from 2012. The increase is likely in part due to increased data availability. Competitive suppliers increasingly reported to EIA in 2014. Overall though, due to the challenges of obtaining data from competitive marketers

[7] Utilities were asked to self-define region. Typically the region was considered to be the regional transmission organization or independent system operator boundary, or in the Western U.S., the Western Electricity Coordinating Council.

and the lack of current data on the Texas market, which has seen a dramatic increase in the number of companies offering renewable energy products in recent years, the sales figures for the competitive market are likely underestimated.

Retail REC sales (unbundled RECs) increased by 1% in 2013, to 31.4 million MWh. The declines are due to decreased purchasing by nonresidential customers. It is possible that the increase in REC pricing in 2013, from around $1.00/MWh to $1.20/MWh, impacted nonresidential sales of unbundled RECs. The lack of aggressive growth could also be due to some large purchasers switching from unbundled REC purchases to PPAs and on-site generation.

2.1.3 CCA Sales

For the first year, we estimate renewable energy sales by CCAs. The sector totaled 9.3 million MWh of renewable energy in 2013, dominated by sales in Illinois. Data come from competitive suppliers, communities themselves, news releases and other public information, as well as our own estimates. These trends are further discussed in Section 3.

2.1.4 Capacity Equivalent of Green Power Sales

At the end of 2013, megawatt-hour sales of voluntary renewable energy represented a generating capacity equivalent of approximately 24,000 MW (see Table 5).[8,9] The dramatic growth from 2012 to 2013 (39%) is due in part to the addition of CCAs to the 2013 survey. Not including CCAs, the voluntary market was 19,900 MW, a 16% increase from 2012.

Since 2007, when total renewable capacity supplying the green power market was 5,100 MW, the amount of renewable energy capacity serving green power markets has increased nearly five-fold.

[8] Capacity estimates are calculated based on reported green power kilowatt-hour sales, assuming capacity factors for each renewable resource type based on industry data and average capacity factors of operating plants. For wind, a capacity factor of 26% was assumed, 85% for landfill gas, 83% for biomass, 65% for geothermal, 42% for hydroelectric, and 14% for solar electric.

[9] "New" renewable energy capacity is defined here as capacity that was sourced from renewable energy systems that were built or repowered after January 1, 1997.

Table 5. Estimated Cumulative Renewable Energy Capacity (MW) Supplying Green Power Markets, 2008–2013

Market Segment	2009	2010	2012	2013
Utility Green Pricing	1,700	1,700	2,400	2,600
Competitive Markets and Unbundled RECs	7,700	9,400	14,900	17,400
CCA		Not estimated		4,100
Total	**9,400**	**11,200**	**17,300**	**24,000**

Note: Totals may not sum due to rounding.

2.2 Voluntary Market Customer Participation

In 2013, approximately 5.4 million electricity customers nationwide purchased green power products through regulated utility companies, from green power marketers in a competitive-market setting, from a CCA, or in the form of RECs (Table 6).[10] Participation in utility green pricing programs and competitive markets rebounded after an essentially flat year in 2012. REC market participation declined overall, due to declines in the number of residential customers. CCA participation totaled approximately 2.4 million, with 2.1 million of those customers coming from Illinois.

[10] It is important to note that there is greater uncertainty in our customer estimates for competitive and REC markets because of data limitations. For more detailed estimates by state for 2009 and 2010, see data from EIA 2011. Generally, our estimates are consistent with the EIA estimates when adjusted for customers in Ohio who participated in community aggregations in 2005 and earlier. We excluded these customers from our estimates because they purchase products with very low renewable energy content (1%–2%).

Table 6. Estimated Cumulative Green Power Customers by Market Segment, 2006–2013

	2006	2007	2008	2009	2010	2012	2013
Utility Green Pricing	**490,000**	**550,000**	**550,000**	**550,000**	**570,000**	**570,000**	**706,000**
Residential	470,800	526,700	519,700	526,300	544,700	549,600	683,600
Nonresidential	15,500	20,200	26,100	26,000	22,900	17,200	22,400
% Residential Growth	23%	12%	-1%	1%	4%	0.4%[a]	24%
% Nonresidential Growth	37%	30%	29%	-1%	-12%	-13%[a]	30%
Competitive Market	**~ 210,000**	**300,000**	**390,000**	**830,000**	**~ 1,200,000**	**~ 1,200,000**	**~2,200,000**
CCA			**Not estimated**				**~2,400,000**
Voluntary REC Market	**~ 10,000**	**> 10,000**	**30,000**	**< 20,000**	**> 60,000**	**~110,000**	**~95,000**
Retail Total	**~ 710,000**	**~ 860,000**	**~ 970,000**	**~ 1,400,000**	**~ 1,830,000**	**~1,870,000**	**~5,400,000**
% Change	~ 22%	~ 21%	~ 13%	~ 44%	~ 25%	~2%	~190%

In some cases, estimates have been revised from those reported in previous NREL reports as updated data have become available. Totals may not add due to rounding.

[a] Compound annual growth rate for 2010–2012.

2.2.1 Utility Green Pricing Participation

The number of green pricing customers rebounded in 2013 to more than 700,000 (Table 6). As in the past, a small number of green pricing programs account for the majority of customers, with just 10 utilities accounting for 68% of all participants.[11] Both residential and nonresidential customers increased in 2013; nonresidential customers increased to near-2010 levels, after declining in 2012.

At the end of 2013, the average participation rate in utility green pricing programs among eligible utility customers was 2.8% with a median of 1.1%. These industry-wide rates have shown little change in recent years. Participation rates in top-performing programs have remained relatively unchanged since 2007, thought they have improved compared to the ranges in early years: top-performing participation rates ranged from 6.5% to 18.2% in 2013, compared to a range of 3.9% to 11.1% in 2003.

Green pricing program drop-out rates are important for program managers to examine, as they may highlight issues with customer satisfaction. Customers may drop out of green pricing programs if they do not perceive real value in their participation, if there was a price increase, or for other reasons, sometimes not related to satisfaction. For example, some programs do not automatically transfer a customer's participation if they move within the utility service territory; it is up to the customer to re-enroll in the program. In 2013, utilities reported that an average of 8.7% and a median of 6.6% of customers dropped out of green pricing programs, consistent with 2012. These figures represent an increase from 2010 when utilities reported an average dropout rate of 7.0% and a median of 4.7%, but the figures are consistent with previous years. In 2012 the median dropout rate was 8.5% and the average was 7.2%; in 2009 utilities reported an average of 7.8% and a median of 6.3%.

2.2.2 Competitive Market Participation

The competitive market grew to 2.2 million customers in 2013, driven by increases in residential customers. Residential customers increased from 1.1 million in 2012 to 2.1 million in 2013. Nonresidential customers also increased from 75,000 to 120,000. Because obtaining data about the competitive market is particularly challenging, these figures likely underestimate the number of participants in competitive market programs. EIA has begun collecting more data from competitive suppliers through its Form 861.

EIA provides customer numbers for both utility green pricing and competitive suppliers, by state. Data for 2012 show that Texas remains the state with the most customers (1.2 million, including utility green pricing customers). Illinois saw a large increase in customers and sales between 2011 and 2012, due to competitive suppliers active in the CCA market, as will be discussed in

---

[11] NREL issues five different Top 10 lists based on total sales of renewable energy to program participants, total number of customer participants, customer participation rates, green power sales as a fraction of total utility sales, and the premium charged to support new renewable energy development. These lists can be found at http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=3.

Section 2.2.3. Maryland, New Jersey, and New York also had large increases in the number of customers.[12]

While the number of green power purchasers has expanded during the past few years in markets with retail competition, participation has been less consistent over time, as some markets have grown and then contracted. Between 2011 and 2012, participation increased in most states with competitive markets, with the exception of Delaware and Maine, which have relatively small numbers of customers to begin with (2,838 and 375, respectively).

Data from EIA also show that state participation rates vary greatly. More than 4% of electric customers in Texas were participating in either a green power or competitive market program, according to EIA data.[13] Several other competitive market states (Connecticut, New York, and Vermont) have seen participation greater than 1% in 2012 and 2011. Over time, participation has generally been more volatile in competitive markets than in traditionally regulated markets.

2.2.3 CCA Participation

Nationwide, approximately 2.4 million customers participate in CCAs purchasing renewables (Table 8). CCAs in Illinois include a total of approximately 2.1 million customer accounts, primarily on the residential side. We do not include Chicago's CCA in these totals because its supply only contains 5% renewable energy, but Chicago's CCA serves approximately 750,000 accounts. In 2015, California's Sonoma County is expected to have an additional 150,000 CCA subscribers. Sonoma County offers a 33% renewable product as its base product and a 100% renewable product for a premium. See Section 3 for more information about CCA participation.

2.2.4 Unbundled Voluntary REC Market Participation

The number of REC-only buyers declined to around 95,000 in 2013, after seeing large gains in 2012. The number of residential REC-only buyers declined from around 87,000 to 71,400. Nonresidential REC-only buyers increased slightly, from around 22,000 to 23,600.

While most REC buyers are residential customers, the majority of REC sales on a megawatt-hour basis are made to nonresidential customers, due to the much larger purchase sizes. As a result of large nonresidential REC purchases, REC sales represented about half of total green power megawatt-hour sales in 2013 (Table 2) and have grown dramatically in recent years.

2.3 Voluntary Market Products and Premiums

2.3.1 Utility Green Pricing Products and Premiums

Typically, green pricing programs are structured so that customers can either purchase green power for a certain percentage of their electricity use (often called "percent-of-use products") or in discrete amounts or blocks at a fixed price ("block products"), such as a 100-kWh block. Most utilities offer block products but may also allow customers to buy green power for their entire monthly electricity use. Utilities that offer percent-of-use products generally allow residential

[12] The EIA figures include customers in both utility green pricing programs and competitive market programs, but they do not include all competitive retailers; therefore, these estimates underestimate the total number of customers but serve to show at a minimum the level of growth in Texas.
[13] EIA data also include participants in utility green pricing programs.

customers to elect to purchase 25%, 50%, or 100% of their electricity use as renewable energy, while a few offer fractions as small as 10%. Under these types of programs, larger purchasers, such as businesses, can often purchase green power for some fraction of their electricity use as well.

More recently, the concept of community solar has emerged. In community solar programs, customers purchase a share of a community solar system. In return, they obtain a proportionate share of the system output, which is credited to them on their utility bills. These programs are offered by utilities or third parties operating in conjunction with utilities. Community solar programs differ in terms of the upfront cost and return payment received by participants. One program, the Holy Cross Energy solar project, sells upfront shares for $3.15 per watt (W) and credits participants at a rate of $0.11/kWh for producing their shares.[14] Community solar programs are addressed in depth in Section 4.

In 2013, the price of green power for residential customers in utility programs ranged from 1.04¢/kWh below standard electricity rates to 4.5¢/kWh above standard electricity rates, with an average premium of 1.77¢/kWh and a median premium of 1.50¢/kWh.[15] These premiums have been adjusted to account for any fuel-cost exemptions granted to green power program participants.[16] This is the first year that average and median premiums have increased. The increase was due to the additional data collection in 2013 from utilities with higher-priced programs. For programs that reported both 2012 and 2013 data, there was little change in average and median premiums; 20 programs had the same premium, 13 programs had decreased premiums, and 5 programs had increased premiums.

Despite the increase in average and median premiums in 2013, from 2002 to 2013, the average price premium dropped at a compound annual rate of 4% (see Figure 4). The general downward trend in price premiums can be attributed to lower market costs for renewable energy supplies or increased competitiveness with conventional generation sources. The competitiveness of wind and other renewables with conventional generation, as well as regional demand from state renewable energy standards, will affect premiums in coming years.

---

[14] For more information, see "Holy Cross Energy Launches 80 kW Community Solar Program" at http://apps3.eere.energy.gov/greenpower/news/news_template.shtml?id=1564 (accessed October 3, 2011).

[15] One program, TVA's Green Power Switch Pure Solar, is 16¢/kWh. We do not include it in the averages or medians because it is an outlier as a 100% solar product.

[16] For example, a small number of utilities exempt green pricing customers from monthly or periodic fuel charges imposed to pay higher-than-expected fossil fuel costs. For a detailed discussion of this topic, see Bird et al. (2008).

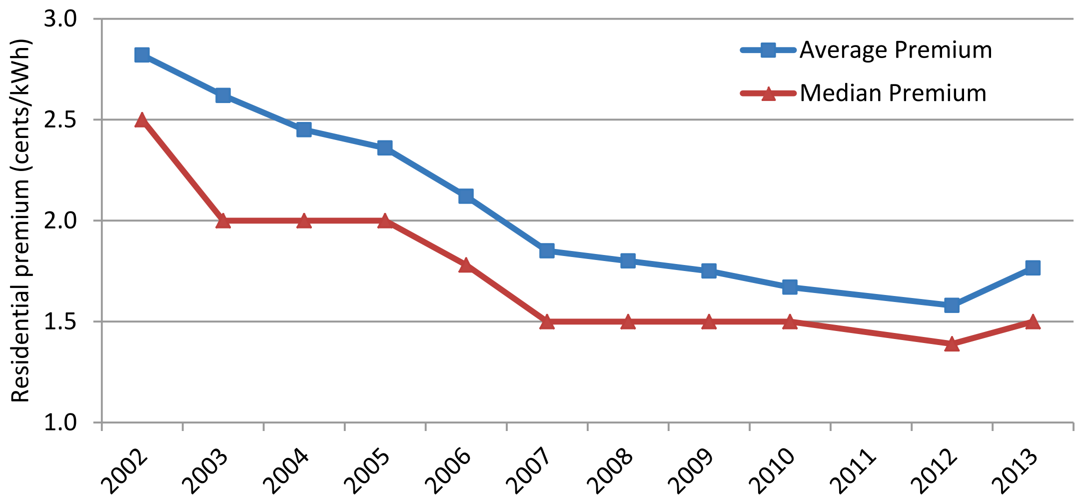


Figure 4. Trends in utility residential green pricing premiums, 2002–2013

Note: Average and median premiums for 2013 do not include TVA's Green Power Switch Pure Solar (16¢/kWh).

2.3.2 Unbundled REC and Competitive Market Products and Pricing

Green power products offered in electricity markets with retail competition tend to differ from those offered by utilities in regulated markets, as they are more likely to be sourced from RECs because suppliers may be less able to enter into long-term contracts with generators.

Green power marketers in competitive markets are often sourcing from new supply, a transition that has been encouraged by green power recognition and product certification programs. Both Green-e Energy[17] and the EPA Green Power Partnership[18] currently operate on a 15-year rolling window for defining a "new" facility, meaning that projects must have come online within 15 years prior to the sale of the green power in order to be classified as new. Under the Presidential Memo on Federal Leadership in Energy Management the Federal government will restrict REC purchases used to meet Federal goals to a 10-year rolling window.

The price premium charged for competitive-market products depends on several factors, including the price of default service and the cost of renewable energy generation available in the regional market. In recent years, some marketers (e.g., in Texas) have charged prices close to or even below the prevailing cost for system power; others have offered fixed-price products, providing customers with protection against increasing prices for a specified period of time—usually one year.

Competitively marketed green power products generally carry a price premium between 1¢/kWh and 2.5¢/kWh for residential and small commercial customers, although offerings have ranged from small discounts to a premium of about 10¢/kWh in recent years. For utility/marketer

[17] Administered by the Center for Resource Solutions, the Green-e Energy program certifies retail and wholesale green power products that meet its environmental standards, product content, and marketing standards. For details on the Green-e Energy National Standard, see the Green-e website at green-e.org.
[18] See the EPA's Green Power website at epa.gov/greenpower.

programs offered in states with retail competition, the average price premium for green power was about 2.1¢/kWh in 2013. In addition, price premiums can change frequently with changes in market conditions. Higher-priced products often contain a larger fraction of new renewable energy content or resources that are more desirable to consumers, such as new wind and solar.

Retail prices charged for REC products are not very transparent. In the past, REC marketers have posted pricing for specific REC product types on their websites, possibly for competitive reasons, but are increasingly now requesting that potential buyers call them for a quote. Wholesale REC prices in 2013 were around $1.20/MWh (see Section 7).

Because RECs are generally not subject to the same regulatory scrutiny as electricity and mandatory renewable requirements, REC buyers often seek certification due to concerns about double counting and to ensure a level of oversight and auditing. Buyers may also be interested in using the Green-e Energy label in communication materials. Nearly all REC products are sourced from "new" renewable energy generation projects as a result of product certification requirements.

Figure 5 shows Green-e Energy-certified retail transactions from 1998 to 2013. Green-e Energy certified 33.5 million MWh of retail transactions in 2013 (Heeter 2014a). This represents a decrease of 7%. Green-e Energy certified retail sales increased in the green pricing market but declined in the competitive electricity and unbundled REC markets.

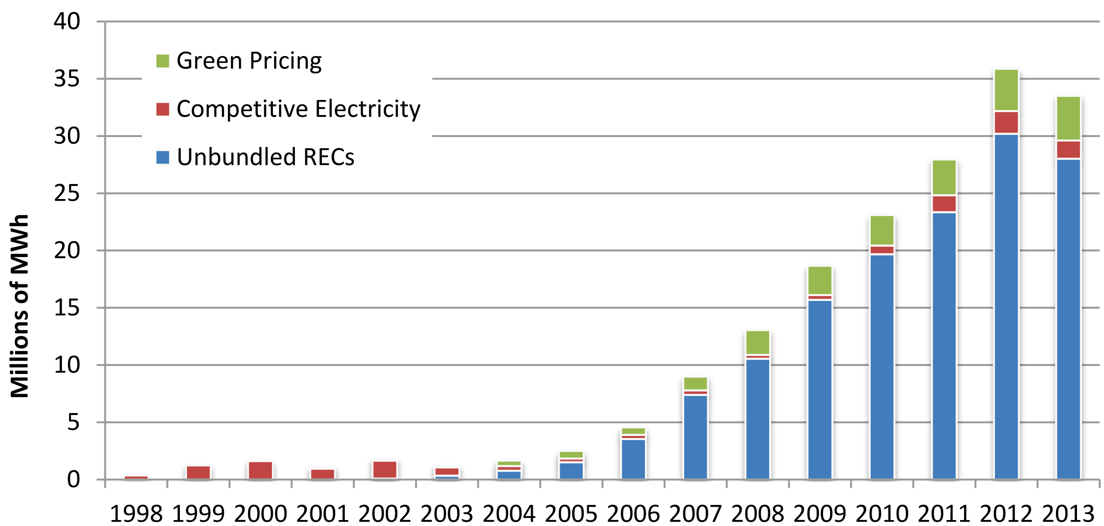


Figure 5. Total retail sales of Green-e Energy certified renewable energy, 1998–2013

Source: Heeter 2014a

The Green-e Energy program also certifies wholesale renewable energy transactions, which totaled 9.7 million MWh in 2013, down from 15.7 million MWh in 2012. It is important to note that 5.3 million MWh sold in certified wholesale transactions were resold in Green-e Energy certified retail transactions. The remaining 4.4 million MWh were sold in non-Green-e Energy certified transactions, most likely to utilities and electric service providers, power marketers, or retail customers. In total, Green-e Energy certified 38.8 million MWh of unique transactions in 2013.

2.3.3 CCA Pricing

CCAs around the country are procuring renewable energy at a savings compared to standard electricity rates. While rates vary, programs have seen savings of up to 21% (see Table 8 in Section 3 for more on CCAs). The level of savings depends on current electricity rates and the renewable energy content of the CCA procurement. In California, both Marin County and Sonoma County have developed base programs that contain 50% or 33% renewables, respectively, that come at comparable or a slight discount, as well as 100% renewable offers, which come at a premium. In Illinois, utilities had been locked in to high-priced contracts while market prices were declining; as a result, CCAs were able to secure supply at cost savings.

2.4 Green Pricing Marketing and Administrative Expenses

Retail product pricing typically reflects the costs involved in attracting and servicing retail customers to some degree, though data on marketing and administrative expenses are challenging to obtain. This section highlights marketing and administrative expenses for utility green pricing programs. While these data help illustrate trends in marketing and administrative expenses, each utility program will face unique circumstances when deciding how much to spend on marketing and administration. For a more detailed look at marketing and administrative expenses, see Friedman and Miller (2009).

Utilities in some cases are working with third parties to market their programs. In 2013, 39% of programs that reported to NREL indicated that they were working with a third party.

Marketing and administrative expenses increase with the size of the utility (measured as the number of eligible residential green power customers in their service territory) (Figure 6).

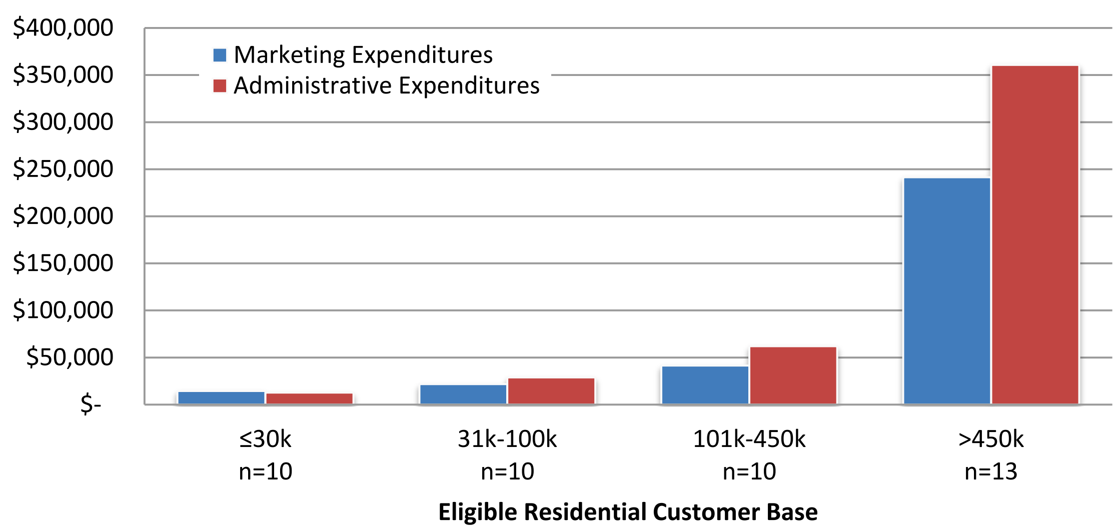


Figure 6. Estimated average marketing and administrative expenses, 2013

While Figure 6 shows that larger utilities spend more on marketing and administration, these increased expenses do not necessarily correlate to increased green power program participation. Large utilities may spend more on marketing in dollar terms because they have a larger territory to cover. Also, in some cases, for example, a new program operating in a large service territory may spend heavily on marketing and administration and see large increases in customer participation, but may not see large increases in the participation rate for a number of years. Correlating marketing costs and participation rates is difficult because of the variation in the offers being marketed. For example, a marketing program for a product with a low premium or even savings and attractive renewable energy is likely to garner more participation per dollar than the same level of marketing for a more difficult product.

3 Community Choice Aggregation

Six states have enabled CCA, giving communities more market power and more control over electricity sourcing while still receiving transmission, distribution, and billing services from the local utility. In the past few years, CCAs have dramatically increased the number of households voluntarily buying renewables. As a result of this market growth, we estimate CCA market size for the first time in this series of annual reports on the voluntary market.

Among the 18 states and districts that have deregulated electricity generation, 6 states have passed further authorization to form entities that act on behalf of most of the customers in a community to bargain for choices in electricity supply that differ from what is available from the local utility (Table 7).[19]

Table 7. States with CCAs

State	Year CCA-enabling legislation passed
Massachusetts	1997 (HB 5117)
Ohio	1999 (SB 3)
Rhode Island	2002 (H 7786)
California	2002 (AB 117)
New Jersey	2003 (P.L. 2003, CH 24)
Illinois	2009 (HB 362)

Transmission, distribution, and billing services are still provided by the local utility, making CCAs a hybrid between traditional utility service and full municipalization of the electricity system. What gives these entities bargaining power is the fact that most CCAs are "opt-out" entities, meaning that the customer is by default part of the aggregation unless the customer opts out. This opt-out arrangement has given community aggregation entities much higher participation rates than utility green power programs. The lowest participation rate for opt-out programs that offer a renewable energy component is around 75%[20] compared to the highest participation rates in the low twenties for the most successful opt-in utility green power programs.

The laws that authorize the formation of CCAs typically require education and majority voter approval, especially if it is an "opt-out" program. The community must go through several steps,

[19] Other states have considered legislation authorizing CCAs. New York, Utah, and Minnesota have all seen bills introduced, but none has moved out of committee as of August 2014.

[20] According to its website, Marin Clean Energy has a participation rate of about 75%. According to news sources, the City of Chicago is serving about 700,000 out of 900,000 customers in its aggregation program, which gives a participation rate of about 78%. The opt-out programs in Massachusetts and Illinois enjoy high participation rates, averaging over 90%, according to spokespeople. The participation rates for the opt-out programs in Ohio were not available, but are expected to be high because of the savings over the traditional rate.

including submitting its plan to the appropriate state agency for approval, then obtaining and approving bids for electricity supply.

Communities may choose to form CCAs for a number of reasons, including lower cost, more cost stability, and local supply. One reason that many entities have been formed is to support renewable energy, which could have the benefits of reducing the community's carbon emissions and air pollutants and supporting local economic development. This section is focused on the CCAs that purchase renewable electricity in addition to any RPS requirement the state may have.

Most often, the mechanism for choosing renewable energy supply is through the selection of an alternative retail supplier that procures generation and RECs on behalf of the participating customers. Some CCAs have stipulated to the alternative retail supplier that they must purchase RECs from local renewable energy projects. Other CCAs work with affiliated agencies that have the legal authority to own generation assets.

CCAs may face conflicting goals; if purchasing renewable electricity is a top priority, the aggregation's offering may be more expensive than the offering from the local utility. One of the communities that pioneered community aggregation in Illinois – Oak Park – did not make renewable electricity part of its 2014 supply contract when its initial contract expired because it would have raised rates higher than the offering that was ultimately chosen.

3.1 CCA Market Overview

Illinois has seen the largest influx of CCA programs offering renewable energy (Table 8). In addition to activity in Illinois, CCAs in California, Ohio, and Massachusetts are purchasing renewable energy, often at a cost savings to customers. Programs that are 100% renewable sometimes come at a small premium. These details are discussed below in a state-by-state overview. Data on CCAs were obtained through direct survey, public information, and NREL estimates.

Table 8. Overview of CCA Programs Offering Renewable Energy

Location	Renewable Energy Content in Product	Type of Renewables	Start Date	Premium and/or Savings	Electricity Customer Accounts	Estimated Annual Sales of Renewable Energy (MWh)
Illinois communities (excluding Chicago)[a]	25%-100%	Varies	2010-2014	Varies	~2,100,000 (NREL estimate)	~7,800,000 (NREL estimate)
Marin County, CA	50% or 100%	Wind, Hydro, Biomass/landfill gas, Solar	2010	100% is $0.01/kWh extra	125,442	1,072,156
Cincinnati, OH	100%	Hydro, Wind, Solar	2012	7% savings	66,751	467,282
Cleveland, OH	100%	Wind, Hydro	2013	21% savings	63,254	253,766
Sonoma County, CA	33% (CleanStart) or 100% (EverGreen)	Geothermal, biomass and biogas, wind	2014	CleanStart 4-5% savings; EverGreen $0.035/kWh premium over CleanStart	154,000+ (2015)	1,750,000 (2015)
Cape Cod and Martha's Vineyard, MA	50% or 100%	Hydro, Solar, Wind	2002	$0.009/kWh to $0.016/kWh, depending on customer class and usage	~1,000	6,700
Lancaster, MA	Local PV incorporated into product mix	Solar	2013	~10% savings	~2,900	Not available
Lowell, MA	100%	Hydro, Solar, Wind	2014	8-10% savings	31,000	Not available
2013 totals					**>2,400,000**	**>9,500,000**

[a] Chicago's municipal aggregation has around 750,000 accounts, for an estimated 110,000 MWh of renewable energy sales. We do not include it in our summary table because the supply contains only 5% renewable energy.

Illinois

The latest state to pass legislation to authorize CCA formation is Illinois. When the electricity restructuring law was changed in 2009 to allow for the aggregation of electric load by municipalities and counties, interest in aggregation spread quickly across the state.

Through mid-2013, over 650 towns and cities in Illinois had formed CCAs, and of those, over 100 had made the choice for their supply to be at least partially from renewable sources through

RECs purchases. According to one count, these purchases represented 1.7 million people and increased demand for renewable energy sources by over 6 million MWh (Englum et al. 2014).

The rapid move to form CCAs was driven in part by market dynamics that allowed CCAs to save customers 25% to 30% of the generation cost, even while supplying customers with renewable energy. In the wake of lower demand caused by the 2008 economic downturn, market prices for generation were very competitive.

In 2012, Chicago became the largest city in the United States to form a CCA. Integrys Energy Services (an alternative retail energy supplier) won the contract with an offering that included no coal-fired generation. Most of the power comes from natural gas, but 5% is sourced from wind power.

However, the market dynamics that made a renewable option so attractive in the first years of the municipal aggregation law may be a double-edged sword. The cost savings enjoyed by the alternative retail suppliers evaporated by the summer of 2014 because contracts that ComEd and Ameren signed with generators when power prices were much higher expired and ComEd and Ameren are also able to obtain market rates.

As of August 2014, about 60 municipalities have allowed their CCA program to expire. A full list of municipal aggregations procuring 100% renewable energy in Illinois is available in Englum et al. (2014). In April 2014, CCA pioneer Oak Park chose to end its contract with Integrys in favor of Constellation Energy. The Constellation Energy product will offer customers an opt-in renewable choice (Fisher 2014). Cost was the main motivation behind the change (Fisher 2014). Because of recent rising electricity prices in the state, all new service contracts would have raised rates as compared to the original contract. The winning bid raised it the least, and the Village Board made the decision that low cost was its top priority. As price dynamics become more challenging for renewable energy options, other municipalities may follow suit.

California

Marin County was the first community in California to launch a CCA. Marin County CCA renewable energy requirements are met with a combination of RPS-eligible contracts and unbundled REC purchases. The default service in the CCA is the "Light Green" product, which is a guaranteed to have a minimum of 50% renewable energy content. Customers are also given an opt-in "Deep Green" choice for a premium of 1¢/kWh. According to the Marin Energy Authority Integrated Resource Plan, the proportion supplied by bundled renewable energy will increase during the planning period and displace purchases of unbundled RECs. The long-term goal is 100% renewable energy for all customers. This goal may be met by new renewable energy projects or unbundled RECs (Marin Energy Authority 2013).

Marin County is now in the process of evaluating new resource offerings for its 2014 Open Season process. The process yielded 32 offers with a variety of technologies including solar photovoltaic, wind, geothermal, and biomass/biogas (Marin Energy Authority 2014).

In the summer of 2014, CCAs fought off an attempt to reduce the market power of aggregators by requiring that programs be opt-in instead of opt-out. That requirement was dropped from

Assembly Bill 2145 during a meeting of the state Senate Energy, Utilities and Communications Committee.

Sonoma County began serving its first group of more than 20,000 customers in 2014. Constellation Energy will supply the majority of the CCA's power needs, including the default "CleanStart" program, which is made up of one-third renewable energy. A smaller contract with Houston-based Calpine Corp., the largest operator at The Geysers geothermal field in the Mayacamas Mountains, will provide a 100% renewable "EverGreen" program product offered as an option for customers at a 3.5¢/kWh premium.

Ohio

The 1999 electricity restructuring law in Ohio authorized the formation of CCAs. Because the motivation of most of the earlier CCA programs was to save money, they tended to be located in the north of the state where electricity rates were higher.

As of May 2014, nearly 200 communities (counties, cities, villages, and townships) in Ohio had community choice programs in place for electricity. A detailed map of the programs is published at the Ohio Public Utility Commission website at http://www.puco.ohio.gov/pucogis/agg/electric.cfm.

In recent years, renewable choice has become an important element of some programs. Cincinnati formed a CCA in 2011. First Energy Solutions won the first contract, which ran through May 2014. Due to market conditions, customers were able to gain large discounts on the generation portion of their bill. The first contract guaranteed customers a 23% discount from their "price to compare" from Duke Energy. Even with this discount, the product was 100% renewable energy. To promote locally sourced renewables, Cincinnati stipulated that the city would receive RECs from the University of Cincinnati's Central Utility Plant from coal mine methane gas and the solar canopy at the Cincinnati Zoo. The source of the rest of the RECs retired was to be at the supplier's discretion.

When Cincinnati's contract was due to be renegotiated in May 2014, the guaranteed savings had shrunk from 23% to 7% for the 100% green option. The Cincinnati City Manager originally decided to drop the green power option in return for another 1% of savings. However, the City Manager's decision was opposed by a majority of the City Council, and he ultimately changed his position (Kiefaber 2014).

Through its CCA, Cleveland is able to offer residents a 100% renewable program at over 20% off their utility's electric generation rate until July 2015. The source for the city's RECs is 30% Ohio wind, 20% out of state wind, and 50% hydropower (Chatterjee 2013).

Massachusetts

The electricity restructuring act passed in Massachusetts in 1997 authorized the creation of the Cape Light Compact, which was the first municipal aggregator in the country. The Compact serves all 21 towns on the Cape, Martha's Vineyard, and Barnstable and Dukes counties.

As of January 2014, the Compact was offering two opt-in products for customers that wanted to buy renewable energy: Green 50% and Green 100%. The Green 100% product consists of 75%

small hydro facilities, 16% from PV systems on rooftops across Cape Cod, and 9% land-based wind projects in Massachusetts. In addition to the 50% that is not from renewable sources, the Green 50% product is made up of 34.9% small hydro facilities, 7.5% wind, and 7.6% local PV systems (Cape Light Compact 2014).

The program advertises that 25% of the renewable energy sources in its green program were built after 1997, which is considered "new." In order to support new, local renewable projects, it has partnered with the Cape & Vineyard Electric Cooperative (CVEC), which was formed to coordinate and finance renewable energy projects on Cape Cod. The program does require its "Green" customers to pay a price premium over the standard offer rate, but strives to keep costs low with aggressive efficiency offerings. As of September 2014, Cape Light Compact's basic residential rate was 8.892¢/kWh. The 50% Green residential and commercial rates were 9.792¢/kWh and the 100% Green residential and non-residential rates were 10.492¢/kWh.

In addition to the Cape Light Compact, two other Massachusetts CCAs offer a renewable component to their electricity supply. The town of Lowell is offering a product that is 100% renewable through alternative supplier Dominion Retail (Colonial Power Group 2014). The town of Lancaster has required its supplier, Hampshire Energy, to purchase all the solar RECs from the PV panels installed on its municipal buildings to provide a funding stream for the PV systems (Belyeu 2014).

As of late August 2014, there were 19 approved CCAs in Massachusetts, which include 39 municipalities. In addition, 36 municipalities are currently seeking approval of their respective municipal aggregation plans (Massachusetts Department of Public Utilities 2014). It remains to be seen whether these communities will incorporate renewable energy into their supply.

Rhode Island

Municipal aggregation was authorized in the Rhode Island Utility Restructuring Act passed in 1996. In 1999, a consortium of 36 Rhode Island municipalities called the Rhode Island Energy Aggregation Program (REAP) was organized under the auspices of the League of Cities and Towns.

In January 2012, the League selected Direct Energy to be its supplier. The packages that Direct Energy offers are priced individually for each municipality based upon its load factors and interests. Each entity is allowed to contract for periods of one to four years. REAP states that this arrangement has won its members cost savings of 20% to 30% over the state's basic service rate.

As of 2012, eleven of the 36 REAP members had chosen renewable energy to be part of their supply contract. The contracts included 5% to 10% renewables. The resources supplying these contracts were northeastern hydropower, biomass, and landfill gas (LeanEnergyUS 2013).

New Jersey

CCA was authorized in New Jersey as early as 1999 in the Electric Discount and Energy Competition Act. However, the fact that the act included an initial rate reduction and a rate cap for standard rates dampened interest in CCAs. In addition, the 1999 act required the signature of each participant, greatly reducing a CCA's market power.

In 2003, the New Jersey Legislature passed the Government Energy Aggregation Act, which eliminated the opt-in provision for residential customers. The law still requires commercial and municipal accounts to opt in during a specified period. Now that the rate cap has expired, interest in community aggregation is growing. A contract may only be rewarded if the rate is lower than the default rate offered by the local utility, except in the cases in which the contract includes a higher percentage of renewable energy than is required by the state's aggressive renewable portfolio standard.

As of 2014, a small group of municipalities has formed aggregations and has selected its competitive suppliers. The motivation behind most of these efforts is lower cost and renewable energy supply is not a priority.

In late 2013, the municipalities of Lambertville and West Amwell announced that they had chosen First Energy Solutions as their generation supplier. First Energy Solutions offers an opt-in "100% green" contract for a rate premium of 1.5¢/kWh, for a total of 10.41¢/kWh.

3.2 CCA Market Implications

Although CCAs have quickly grown the market for voluntary unbundled RECs, some have raised questions about the extent to which this market demand has promoted the development of new renewable projects (Farrell 2014). From the experience of the small number of states that have experimented with CCA programs, there are a number of goals that may be driving CCA formation, and obtaining all the possible benefits of aggregation may not be possible at the same time. CCA contracts can be written in order to support new, local renewable energy project development, if that is of primary importance to the community. That goal may be at odds, however, with the goal of saving the largest amount of money. In California, the approach of buying unbundled RECs in the short term while building up local renewable project ownership gives communities a carbon benefit with greater price stability. The experience in Ohio and Illinois shows that purchase of unbundled RECs from non-local projects to reduce the carbon content of purchased electricity may be compatible with cost savings, but the costs are vulnerable to market swings.

4 Community and Crowdfunded Solar

Community solar programs provide solar access to electricity customers who cannot or choose not to install solar on their rooftop. Cases of unsuitability occur when electricity customers rent their residence, or reside in a home with suboptimal roof orientation for a solar installation or in a shaded area. Customers may also prefer to participate in a community solar program rather than install solar on-site because the transaction may be easier and may provide more financial benefits. Development of a community solar program allows electricity customers to purchase shares of a renewable system and derive environmental and economic benefits from its production.

For example, Soveren Solaris, a solar installation company in Vermont, plans to open at least four new community solar farms in the upcoming years. The company started construction of an initial 150 kilowatt solar farm in North Springfield in the spring of 2014. Under the community solar model, any Green Mountain Power (GMP) customer can purchase panels at a cost of $3.00/W in the solar array and the electricity the panels generate is credited towards the payment of electricity consumed at the customer's place of residence or business. Customers can use a 30% federal tax credit to aid in financing of their investment, in addition to Vermont's 7.2% investment tax credit (Weiss-Tisman 2014).

Community solar programs are underway in an increasing number of states (19 as of September 2014). As of September 2014, 64 community solar programs were operational around the country, totaling more than 40 MW of capacity (Figure 7). According to Campbell et al. (2014), the average community solar program has 213 participants and programs are around 70% subscribed.

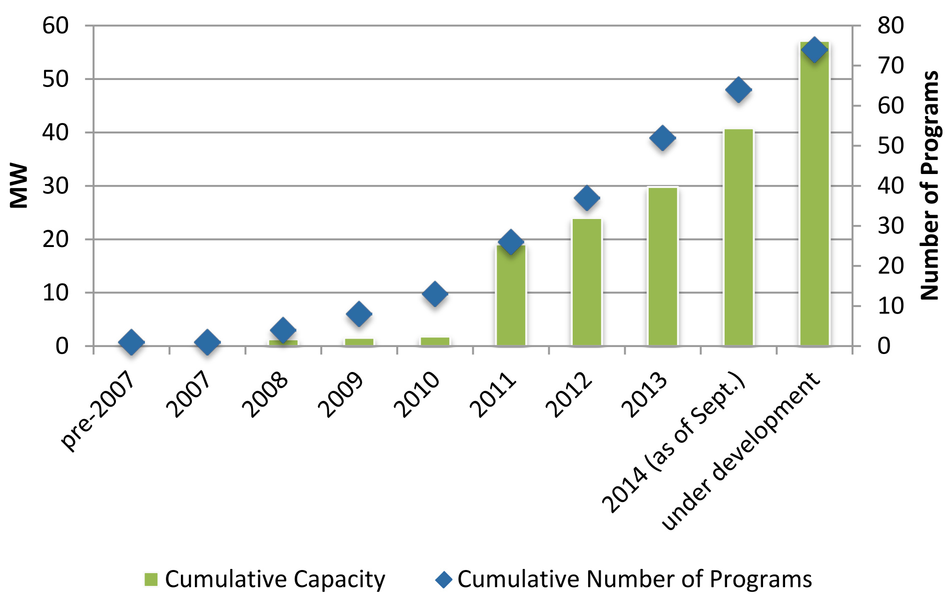


Figure 7. Number and capacity of community solar programs

California is poised to dramatically increase the amount of community solar available. IOUs in the state are planning to purchase up to 600 MW of new, renewable energy capacity from distributed generation projects that are under 20 MW in response to Senate Bill 43 (SB 43). SB

43 requires California's three largest investor owned utilities to develop two forms of clean energy options for their consumers. One of the green energy programs is a "Green Tariff", which will provide customers the option of paying a premium to purchase energy from a new, renewable resources portfolio located within their utility's territory. Similarly, the "Enhanced Community Renewables" program will provide the option of paying a premium to purchase energy from green resources, but the energy source could be located within 10 miles of the customer's place of residence or within the city or county of the customer (Frederick 2014). California's IOUs have proposed programs and are waiting for approval from the California Public Utilities Commission.

Legislative efforts in other states are also fostering increased community solar development. In 2013, Minnesota passed a law requiring Xcel Energy to set up and operate a community solar program. Xcel Energy is in the process of holding discussions with stakeholders on the community solar gardens program.

In Colorado, community solar projects are concentrated in Xcel Energy's service territory. Xcel Energy approved 12 community solar projects in 2013, ranging from 500 kW to 1500 kW, building upon the approval of 13 community solar projects in 2012, ranging from 108 kW to 1997 kW (Xcel Energy 2014).

In May 2009, Washington passed Senate Bill (SB) 6170, which allowed community solar projects to receive a production incentive, in addition to participating in net metering. For owners or participants of community solar projects of up to 75 kW in size, the base rate is 30¢/kWh. Each participant may obtain up to $5,000 per year in incentives. To qualify for these community solar incentives, projects must be located on local government property and require partnerships between governments, solar developers, and community members (DSIRE 2014).

In Washington, D.C., the Community Renewable Energy Act of 2013 (Bill No. 20-0057) was approved by the City Council in October 2013. The Act enables community solar and other aggregated net metering arrangements. Projects can be up to 3 MW in size and must have at least two subscribers. To date, no projects have been developed.

In Maine, there is no community solar requirement, but the state does have a pilot program to incentivize development of locally-owned renewable energy resources. In addition to virtual net metering, individual system-owners can qualify for incentives on up to 10 MW of generation. Participants can qualify for an incentive of 10¢/kWh generated under a long-term contract up to 20 years with their utility, or they can qualify for a renewable energy credit incentive worth 1.5 times the value of the electricity generated by the system. To be eligible for the program, the system must be grid-tied and at least 51% of the system must be owned locally (Clean Energy Authority 2014).

Crowdfunded and Related Programs

Crowdfunding is used to finance many types of projects, not just renewable energy. Kickstarter, for example, is a platform through which individuals can support a wide variety of crowdfunded projects. Crowdfunding renewable projects differs from community solar in that crowdfunding participants provide upfront capital to support the development of the project rather than purchase shares of the project. Crowdfunded programs allow anyone, regardless of utility territory, to invest in the development of a renewable project. However, crowd-funders do not receive bill credits, RECs, or a price hedge against future electricity rate increases.

Mosaic, based in California, is a peer-to-peer lending platform[21] specifically for solar development. Mosaic's program provides lenders the opportunity to finance a solar facility, which is typically hosted by a nonprofit organization, though access may be restricted to certain states or accredited investors. To date, Mosaic has financed 29 solar facilities totaling more than 30 MW. The majority of projects (15) are located in California; other projects are located in Arizona, New Jersey, Florida, New Mexico, Connecticut, and Colorado. The first five projects were funded by more than 400 people for a total of more than $350,000 in zero-interest loans. Mosaic now offers projects with an annual return ranging from 4.4% to 7.0%.

VillagePower provides a platform that helps community organizations manage and finance solar energy projects by crowdfunding or aggregating investments from individuals within the local community and, when necessary, raising funds from investors interested in social responsibility. As of August 2014, VillagePower has 25 projects under development ranging in size from 22 kW to 40,000 kW; the vast majority of the projects will be located in California (VillagePower 2014).

RE-volv.org allows community members interested in supporting renewable energy to directly finance community solar projects. Through RE-volv's website, online tax-deductible donations are pooled and invested in solar energy on facilities that serve as community centers. RE-volv leases solar energy systems to the communities it serves for a period of 20 years. The lease payments are continually reinvested in additional community solar projects, thereby creating a revolving fund.

A new solar crowdfunding platform launched in April 2014 – CrowdSun.com. According to its website, the company has raised over $2 million across 11 campaigns as of October 2014. Accredited investors can buy CrowdSun Bonds, and then receive payments each month consisting of a return of principal plus interest. Funded projects include solar and geothermal for a school house in North Carolina and a 425-kW solar park for a major U.S. consumer products company in New Mexico.

[21] Mosaic's web site informs that the company's services are not representative of a crowdfunding program as referenced in Title III of the Jumpstart Our Business Startups Act (JOBS Act).

5 Sector Spotlight: Information and Communications Technology (ICT)

Consumers are increasingly accessing information online, through smart phones, social media, and online entertainment, including video streaming. As a result, energy usage in the ICT sector, particularly at data centers, has been growing rapidly. These customers are unique in that they have large, stable, long-term electricity load; they are purchasing in deregulated markets where there are opportunities for financial benefit. The ICT industry, including end-user devices, telecommunications networks, and data centers, accounted for 1.9% of global GHG emissions in 2011 and that number is expected to rise to 2.3% by 2020 (GeSI 2012).[22] When looking at electricity use by data centers in the U.S., Koomey (2011) found that U.S. data centers accounted for between 1.7% and 2.2% of U.S. electricity use in 2010.

Given the large and growing electricity footprint of ICT companies, many are engaging in a range of voluntary efforts to procure renewable energy. Some companies are procuring renewable energy as part of their plan to reduce GHG emissions. Hodum and Molitor (2013) found that 50% of Fortune 100 information technology companies have a GHG reduction target and 20% have both a GHG reduction target and an RE target; 33% of Fortune 100 telecommunications companies have a GHG target and 67% have both a GHG and RE target. At least six ICT companies have set goals to be 100% renewable: Apple, Facebook, Google, Rackspace, Box, and Salesforce.

Using data from EPA's GPP, the Carbon Disclosure Project, and company annual reports, we estimate the largest 70 ICT companies in 2013 used 23.4 million MWh of electricity, which is equivalent to 1% of industrial/commercial electricity use in 2013. Of the 23.4 million MWh, 36% (8.4 million MWh) was renewable energy. More than 80% of the sector's renewable energy purchasing comes from Intel, Microsoft, Google, Apple, Hewlett-Packard, and Cisco Systems, though many smaller ICT companies are purchasing green power equivalent to 100% or more of their electricity use.

A number of these ICT companies are seeking to create a more direct impact on renewable energy development by entering into long-term contracts for renewable generation or increasingly investing in on-site resources. Some companies have been making direct investments in renewable energy facilities, while others are working with utilities to purchase through new special tariffs. Although not the focus of this section, these companies are also innovating in efficiency – making data centers and end-user devices more efficient. This section highlights recent innovations and efforts in renewable energy procurement by Google, Microsoft, Apple, and Verizon.

Google

Google has a wide variety of involvement with renewable energy, including direct investments in renewable energy facilities and companies, and purchases of renewable generation through on-

[22] Although end-user devices accounted for nearly 60% of ICT emissions in 2011, data center emissions are expected to grow more rapidly (7.1% per year, compared to 4.6% per year for networks and 2.3% per year for end-user devices).

site generation, long term PPAs, and utility tariffs. Google uses 24% renewable energy and purchases carbon offsets for 65% of its electricity; the remaining 11% is renewable energy already on the grid. To date, Google has committed over $1.5 billion to renewable energy projects, satisfied through multiple types of contract structures and partnerships with a wide variety of green power providers. To supply its data centers, Google has signed PPAs with wind farms located on the same power grid as its data centers. Google buys bundled electricity and RECs directly and then sells the electricity back to the grid, keeping the RECs (Google 2013a). In order to buy and sell electricity, Google created a subsidiary, Google Energy, and received approval from the Federal Energy Regulatory Commission (FERC) to buy and sell wholesale electricity.

In addition to PPAs, Google is working with utility providers to develop renewable energy tariffs for large purchasers (See Text Box 2). Google notes that this type of tariff allows utilities to focus on their key capabilities and minimizes transaction costs (Google 2013b).

Companies are also supporting renewable energy in other ways. For example, Google makes direct financial investments in renewable facilities. It invested $100 million in a residential solar fund with SunPower Corporation in April 2014. Google has also made investments in large-scale solar and wind facilities. In September 2014, Google invested $145 million in an 82-MW solar facility in Kern County, California.

Microsoft

Microsoft is the second-largest purchaser on EPA's GPP Tech and Telecom list, after Intel, purchasing 1.3 million MWh of renewables, representing 50% of its total electricity use (EPA 2014). Microsoft assesses a fee on carbon emissions to its internal business groups. The carbon fee supports Microsoft's carbon reduction policy – to make its operations carbon neutral – and its investment strategy. Microsoft uses the fee to fund investments that help achieve its carbon reduction goal. For example, it has used funds to sign long-term power purchase agreements for wind energy (Microsoft 2014).

Microsoft has a 20-year PPA with RES Americas for the energy from the 110-MW Keechi Wind facility in Texas. Microsoft also signed a 20-year PPA with EDF Renewable Energy for the 175-MW Pilot Hill Wind Project in Illinois. Wind facilities are located on the same grids as Microsoft data centers. (Microsoft 2014)

Apple

Apple is purchasing more than 626,000 MWh of green power, the equivalent of 92% of its electricity use. Of that, 115,000 MWh are from on-site biogas for use in fuel cells and from solar projects, making it the second largest user of on-site green power in the EPA's GPP (EPA 2014). 100% of Apple's data centers are powered by renewable energy (Apple 2014).

Apple's policy for renewable energy procurement is to invest first in self-generated on-site projects, then to use local, grid-purchased renewables, and finally purchasing unbundled RECs only when it is not possible to develop on-site solutions due to local regulations.

In Nevada, Apple is working with NV Energy to participate in the utility's large customer renewable energy tariff. The tariff, called the GreenEnergy Rider, Option 2, allows large customers to individually negotiate sourcing of renewable energy from projects in NV Energy's service territory, with no application fee or monthly administrative charge (NV Energy 2014). Contracts are approved on an individual basis by the Nevada Public Service Commission (NV Energy 2014). The tariff allows Apple to support an 18-MW to 20-MW solar facility near Fort Churchill, close to where its data center is located. See Text Box 2 for more information about renewable energy tariffs.

Verizon

Verizon has made part of its corporate mission to be the greenest wireless carrier in the country. In August 2014, Verizon announced plans to invest $40 million into 10.2 MW of solar power in five states across the country, on top of its existing 14.2 MW of on-site fuel cell and solar power (Verizon 2014). This initiative follows Verizon's announcement of a GHG emission intensity reduction goal of 50% by 2020. Similarly to Apple, Verizon views these investments as more than just an environmentally responsible action. Verizon invests in on-site renewable energy due to the reliability benefit it provides.

Text Box 2: Renewable Energy Tariffs for Large Utility Customers

The ICT sector has been pushing utility companies to offer green power programs tailored to large utility customers. Google published a white paper in 2013 advocating for utilities to develop a "renewable energy tariff" for large customers (Google 2013b). Three utilities currently offer renewable energy tariffs for large customers:

- Duke Energy Carolinas Green Source Rider: Customers pay the difference between the all-in cost of the renewable energy and RECs and the avoided cost of the renewable energy, in addition to a $2,000 application fee and monthly administrative charge of $500 + 0.02¢/kWh.
- Dominion Virginia Power Rider GH: Customers pay the difference between the all-in cost of the renewable energy and RECs and the customer's retail rate, in addition to a monthly administrative charge of $500 + 0.6¢/kWh-0.7¢/kWh.
- NV Energy GreenEnergy Rider, Option 2: Customers pay the cost of the renewable generation under a specialized contract to be approved by the Public Utilities Commission of Nevada. Customers pays the base electricity rate plus the incremental cost of the renewable resource, minus a renewable energy development surcharge.

For more information on large customer renewable energy tariffs, see Proudlove and Kennerly (2014).

6 REC Tracking Systems

States and others have created REC tracking systems to verify compliance with RPS targets. Tracking systems are also used for the voluntary market, though their use is not as predominant as in compliance markets. The Green-e Energy certification program, a leading certifier and auditor of RECs in the voluntary market, allows green power suppliers to use tracking systems to simplify some parts of the Green-e audit process. In 2013, 64% of Green-e Energy retail sales used a REC tracking system (Heeter 2014a).

These electronic tracking systems ensure that RECs are only "retired" (used to meet compliance or substantiate a voluntary claim) once by assigning a unique serial number to each megawatt-hour of renewable energy generation, which constitutes a REC.

Any generator that wants to be issued RECs in a tracking system must first register with the tracking system and provide information about the generator (e.g., type of renewable generation, project location). Tracking systems then issue RECs on a regular schedule based on the output of the generator. Output must satisfy the metering and verification requirements specified by the tracking system. RECs are issued to the generator's account, or to the account of an appointed representative. Market participants who have accounts with the tracking systems can transact the RECs; RECs can only reside in one account at a time.

In the United States, there are currently nine different tracking systems. REC tracking systems, in some cases, follow the same boundaries as local regional transmission organizations or independent system operators (Figure 8).

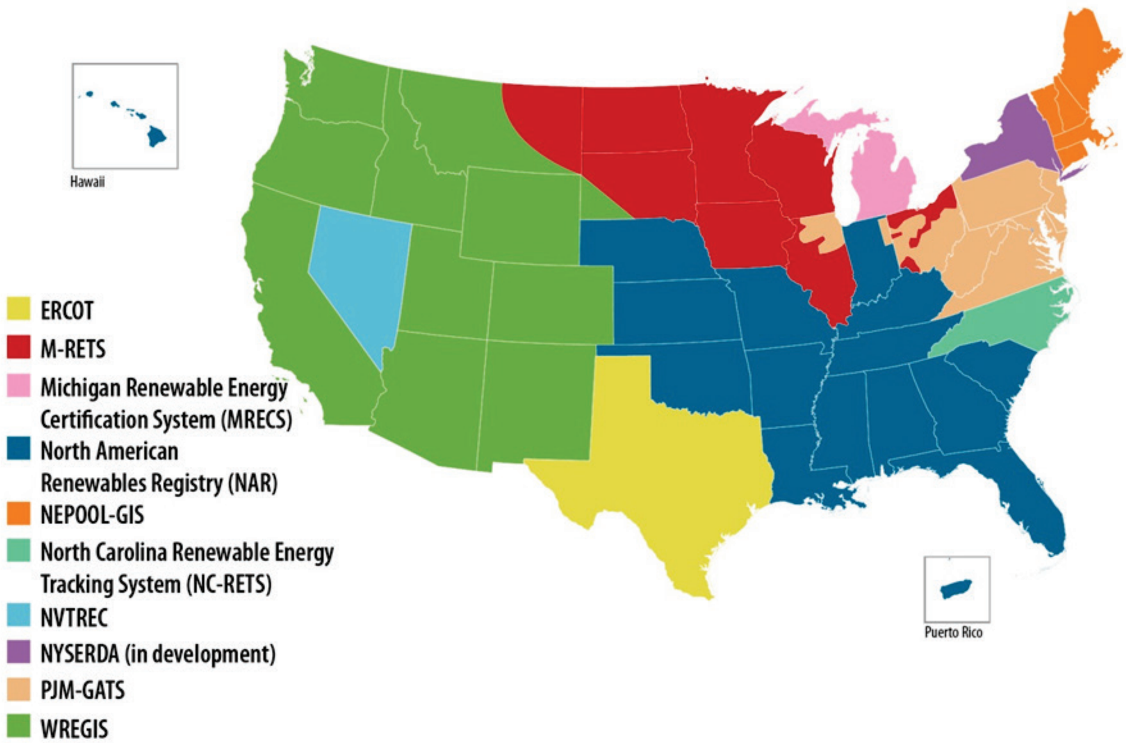


Figure 8. U.S. renewable energy tracking systems

The North American Renewables Registry (NAR)[23] covers states and provinces not covered by an APX, Inc. tracking system.
Source: Updated from ETNNA 2011

Tracking systems are evolving to incorporate additional functionalities. The ability of tracking systems to transfer RECs in and out of their system (exporting or importing of RECs) has increased over the past few years (see Table 9). In addition to the capabilities reported in Table 9, M-RETS has approved imports from NC-RETS, MIRECS, and NAR, though the import capability has not been developed yet. Import/export capability is important particularly in cases where RECs from beyond a state's region are eligible to meet RPS compliance. For example, in North Carolina, 25% of compliance can be met with out-of-state RECs (i.e., from anywhere in the United States). Delaware and New Jersey accept RECs that have been delivered into PJM along with the electricity.

[23] For more information, see the "Registries" Web page at http://narecs.com/resources/registries.htm (accessed September 18, 2013).

Table 9. Export/Import Capability of REC Tracking Systems

Exporting From	Exporting To
NAR	NC-RETS[a]
NC-RETS	NAR
NAR	MIRECS
MIRECS	NAR
M-RETS[b]	NAR
M-RETS	NC-RETS
M-RETS	MIRECS
PJM-GATS[c]	MIRECS
PJM-GATS	NC-RETS
WREGIS[d]	NAR
WREGIS	NC-RETS
ERCOT[e]	NC-RETS

Source: NAR 2014
[a] North Carolina Renewable Energy Tracking System
[b] Midwest Renewable Energy Tracking System
[c] PJM-Generation Attribute Tracking System
[d] Western Renewable Energy Generation Information System
[e] Electric Reliability Council of Texas

In addition to export/import capability, tracking systems are updating protocols for including small generators, such as rooftop solar. Tracking systems are, in some cases, accommodating aggregators, entities who enter registrations on behalf of a large number of distributed generation (DG) projects. One challenge for incorporating DG into tracking systems is that, compared to larger systems, it can be more difficult to validate data. Facilities, regardless of size, need a unique identifier. Larger systems typically have an EIA identification number and/or GPS coordinates that can serve as a unique identifier, but small systems will have to rely on a combination of the facility name, zip code, meter ID, or other identifying information. In February 2014, APX released its Distributed Generation Toolkit for REC Registries (APX 2014). The toolkit provides solutions for how tracking systems can incorporate DG.

Tracking systems can be important providers of public market information. They can provide information on the number of RECs retired in a given year. The Texas PUC has encouraged public access to REC market data by requiring ERCOT to report annually the aggregate quantity of RECs retired for voluntary and compliance purposes. In the current reporting year confidentiality is ensured to account holders that may be retiring compliance or voluntary RECs. After one year confidentiality expires and ERCOT publishes how many RECs were retired by each account holder.[24]

[24] ERCOT's Annual Report on the Texas Renewable Energy Credit Trading Program can be found at www.texasrenewables.com/reports.asp.

In ERCOT, voluntary retirements increased slightly in 2013, when retirements for previous years are included. In 2013, 7.4 million MWh were retired for compliance year 2013 and an additional 7.5 million MWh were retired for 2011 or 2012. A significant number of RECs are being retired in subsequent compliance years for the previous year; as of August 2014, an additional 9.9 million MWh were retired for compliance year 2013 (Heeter 2014b).

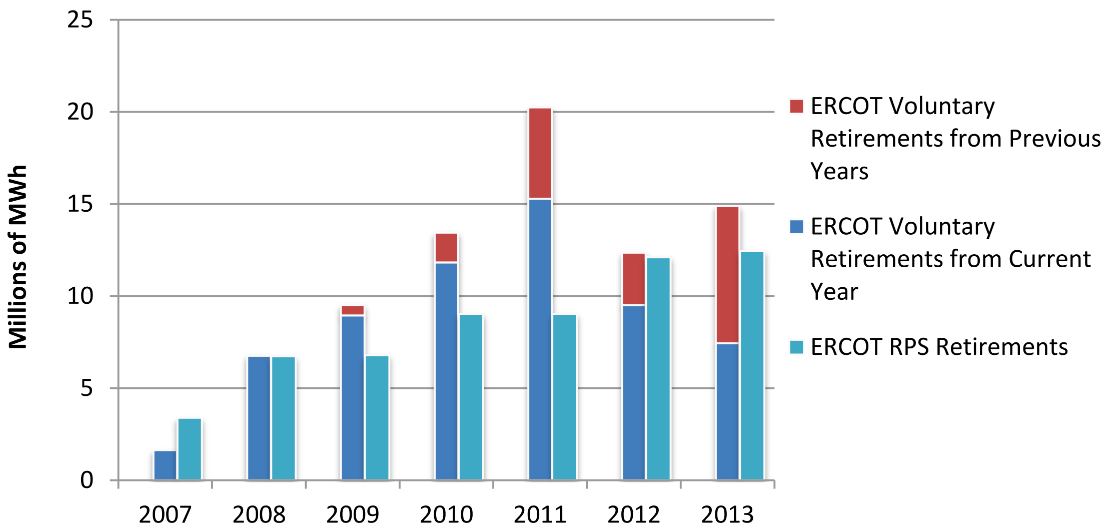


Figure 9. Compliance and voluntary retirements in ERCOT, 2007–2013

PJM-EIS has developed a public report on voluntary retirements, and other tracking systems are publishing the retirements of Green-e Energy eligible (not necessarily retired) RECs.[25]

[25] PJM-GATS public reports can be found at pjm-eis.com/reports-and-news/public-reports.aspx. In addition to voluntary retirements, PJM-EIS provides publicly available data on the RECs retired to meet RPS compliance in PJM states.

7 REC Pricing in Voluntary and Compliance Markets

Pricing for voluntary RECs differs from compliance REC pricing and from pricing offered by utility green pricing programs. Unlike compliance RECs, which typically must be sourced from within some geographic region to be eligible for RPS compliance, voluntary RECs can be sourced either regionally or nationally.

The overview of wholesale REC prices presented in this section is based on indicative data available from brokers and third-party data providers. With a few exceptions, there is little price transparency in REC markets. Most transactions are conducted as bilateral contracts between parties, and prices are not reported. In addition, prices can vary widely by region. Therefore, data presented here are only indicative and should be used with caution.

In general, REC values depend on several factors, including the technology, the vintage (year in which it was generated), the volume purchased, program eligibility (e.g., Green-e Energy), the region in which the generator is located, and the market supply/demand balance. Natural gas prices can also affect the cost competitiveness of renewable energy generation, which is reflected in REC prices.

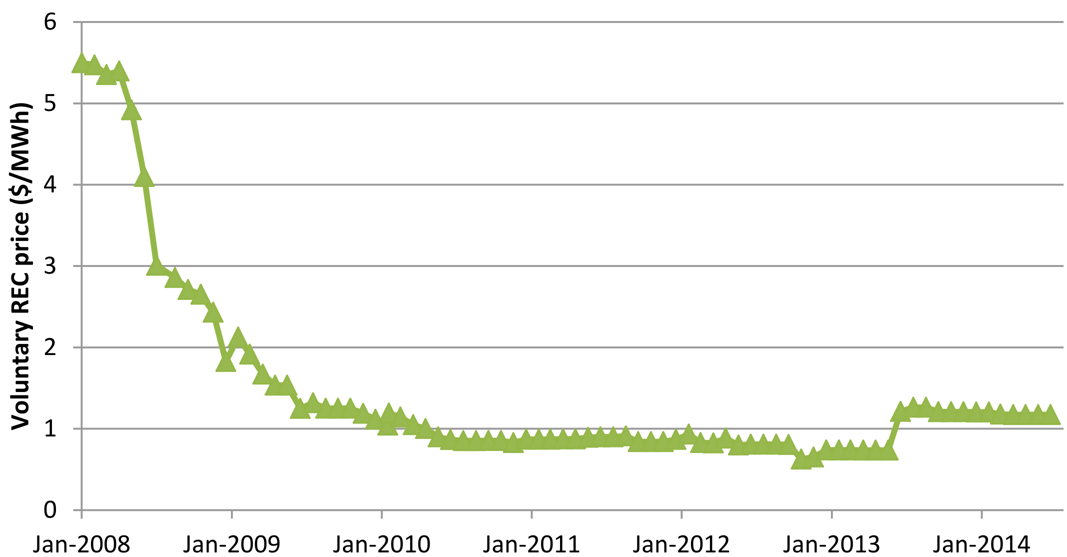


Figure 10. Voluntary national wind REC prices, January 2008–July 2014

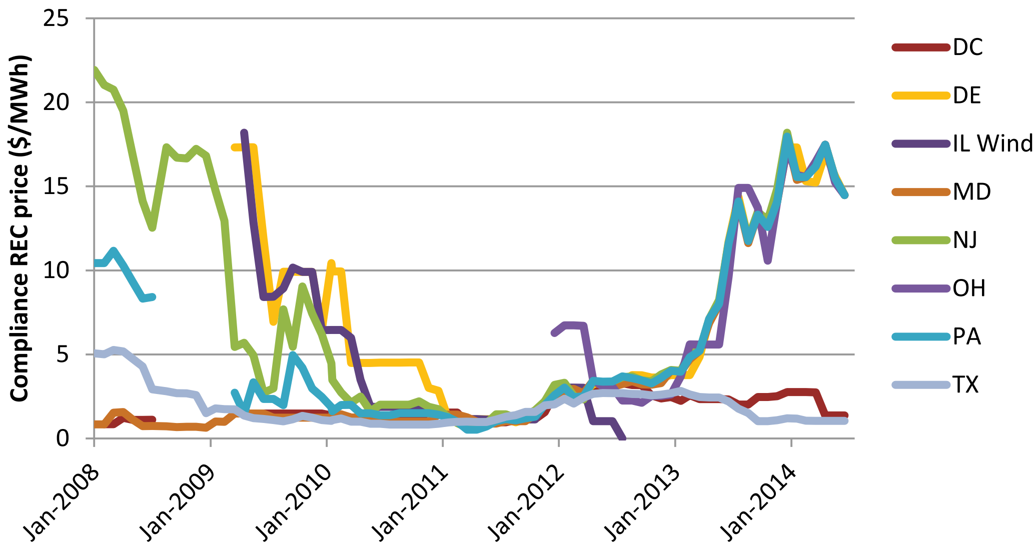
Source: Marex Spectron 2014

As shown in Figure 10, wholesale RECs used in the voluntary market have traded at less than $2/MWh since 2009. As of July 2014, prices remained around $1.20/MWh, after dipping below $1/MWh for most of 2010 through mid-2013.

REC Pricing in Compliance Markets

Since the second half of 2011, REC prices in the Northeast, with the exception of Maine, have continued to remain in the $50/MWh to $65/MWh range. These prices are near alternative compliance payment (ACP) levels in Connecticut, Massachusetts, New Hampshire, and Rhode Island, while declining to around $5/MWh in Maine (Figure 11). Maine has seen an increase in eligible generators, particularly biomass generators restricted from other state markets, causing REC prices to decline (Prince 2014). ACP levels in the region are generally between \$55/MWh and \$65/MWh, meaning that if REC prices were to increase above that level, compliance entities would likely pay the ACP instead of buying RECs.

In other regions, RECs traded at less than \$5/MWh in 2013, though some markets began to increase in 2013 and continued to trade at more than \$15/MWh in early 2014. REC trades in the mid-Atlantic were closing above \$15/MWh in July 2014 in Delaware, Maryland, New Jersey, and Pennsylvania. In Texas, REC prices returned to 2011 levels of around \$1/MWh, compared to highs in the mid-\$2/MWh range in 2012.



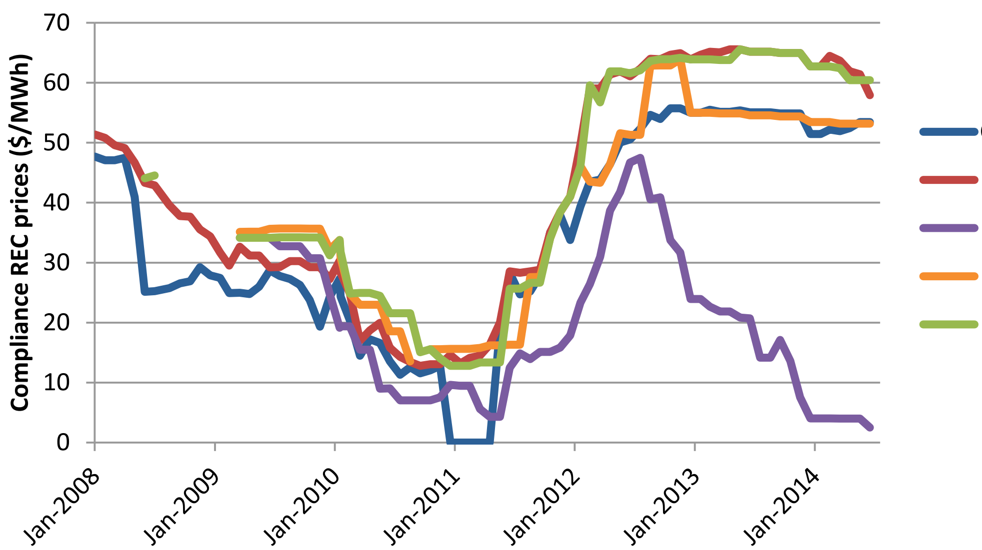


Figure 11. Compliance market (Tier 1) REC prices, January 2008–July 2014

Plotted values are the last trade (if available) or the mid-point of bid and offer prices for the current or nearest compliance year for various state compliance RECs.

Source: Marex Spectron 2014

Solar RECs have higher values than RECs from other resource types in compliance markets. This is true for several reasons. First, 17 states and Washington, D.C., have specific provisions to encourage solar or customer-sited generation (DSIRE 2014), which creates a different supply and demand dynamic than for REC markets in general. Second, the ACP level is often set higher for solar/distributed generation tiers than for standard RPS compliance because of the higher cost of solar relative to other renewables that may be used to meet the main RPS targets. For example, solar ACPs generally range from about $350/MWh to $650/MWh compared to about $55/MWh for the main RPS (Tier 1).

Spot pricing for solar renewable energy certificate (SRECs) is publicly available via platforms like SRECTrade and Flett Exchange.[26] SRECTrade hosts a monthly auction, while Flett Exchange is an online exchange. Both platforms cover markets in PJM states, Massachusetts, and Ohio, and similar price trends can be seen in reported data from both companies. Figure 12 shows SREC prices for the current or nearest compliance year.

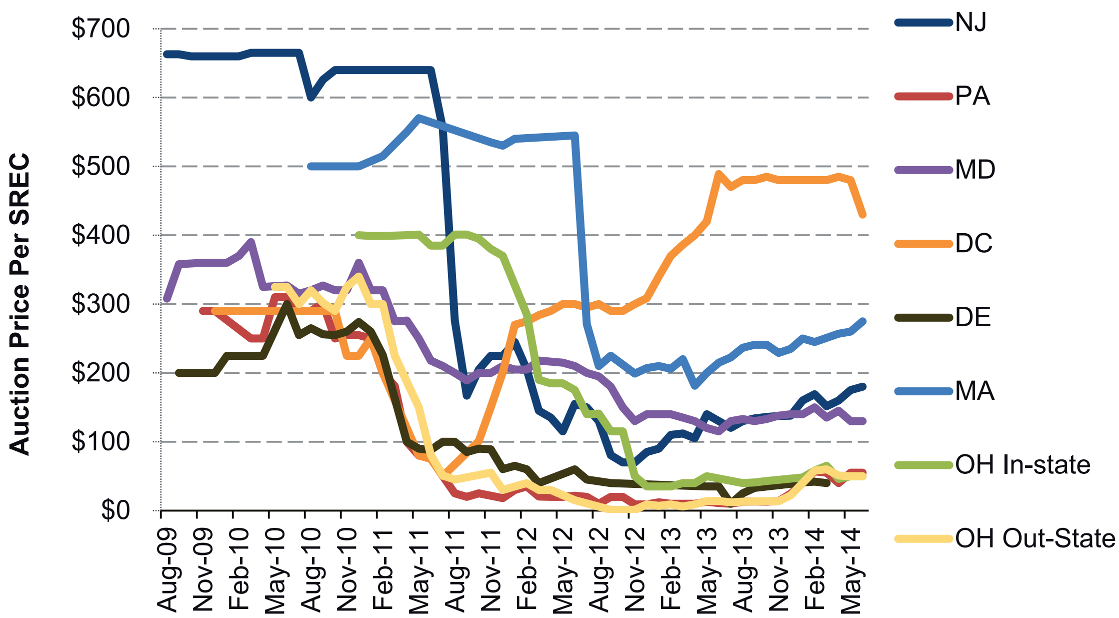


Figure 12. Compliance market SREC spot prices, August 2009–July 2014

Source: SRECTrade

In New Jersey, spot market prices for SRECs have been in the $50 to $150 range in recent years, after declining dramatically from highs of more than $600/MWh into mid-2011. In Pennsylvania, a similar, though not as dramatic, decline was seen in mid-2011. Spot prices for Pennsylvania SRECs dropped to less than $50/MWh in mid-2011, from around $300/MWh in mid-2010 (Figure 12), presumably due to oversupply in the market. By 2012, Pennsylvania SRECs were down to $50, and have declined to less than $15 in mid-2013.

[26] For more information, see www.srectrade.com and www.flettexchange.com.

In Washington, D.C., SREC spot prices have increased in recent years, due to policy modifications. In 2011, the Council of the District of Columbia closed the door to new out-of-district resources (out-of-district systems approved before January 31, 2011 were grandfathered in) and increased the ultimate solar requirement from 0.4% to 2.5% by 2023. In 2012, SREC prices ranged from $270 to $310, increasing to nearly $490 in 2013.

8 Conclusions and Observations

The voluntary green power market provides a way for individuals and institutions to support renewable energy. Historically, the voluntary market has included three market sectors: utility green pricing programs, competitive suppliers, and unbundled REC markets. Emerging methods for support include CCA, community solar programs, crowdsourced solar, and renewable energy tariffs for large customers.

Interest in products that provide a direct impact on renewable energy development is increasing. Utilities have begun offering programs for large industrial customers and are incorporating more local solar resources into their product mixes. CCAs are examining ways to buy local renewable resources. Large corporate purchasers in the ICT sector are turning towards direct investment, long-term contracting, and other mechanisms to spur voluntary renewable energy development and/or realize financial gain. Based on these emerging methods, as well as data from green power programs, competitive markets, and unbundled REC purchases, we have identified the following market trends:

- In 2013, voluntary retail sales of renewable energy totaled 62 million MWh and represented approximately 1.7% of total U.S. electricity sales. From 2012 to 2013, total green power market sales increased 27%.[27]
- Approximately 5.4 million customers are purchasing green power. The number of customers in utility green pricing programs and the competitive market increased by 25% and 87%, respectively, while declining by 14% in the unbundled REC market. Residential REC market customers declined more than 20%, while nonresidential REC market customers increased by 4%.
- For 2013, we found approximately 2.4 million customers participating in CCAs that source renewable energy, totaling more than 9 million MWh of renewable energy.
- Utility green pricing sales exhibited strong growth of 15% in 2013, primarily due to sales increases in some of the largest programs.
- Competitive markets grew to 14.5 million MWh, a 25% increase from 2012, due in part from increased data availability. More competitive suppliers are reporting to EIA through the Form 861.
- Unbundled REC markets saw little movement in 2013, increasing just 1%, to 31.4 million MWh. Increase in wholesale REC market prices and shifting customer demands may be causing the lack of aggressive growth seen in previous years.

[27] In this report, we gathered data and estimated the size of the CCA market for the first time. Because we include this market in the total sales figures for 2013 but not for 2012, some of sales growth from 2012 to 2013 is overestimated.

- Wind energy continues to provide the most renewable energy to the voluntary market, at 75% of total green power sales, followed by landfill gas and biomass (7%), hydropower (4%), solar (1%), and geothermal (1%). The source for 12% of supply is unknown, though is likely mostly wind. Of the voluntary market sectors, green pricing programs are using the most solar; the percent solar used in green pricing programs increased from 2.0% in 2012 to 2.5% in 2013.
- The number of community solar programs is increasing. In 2013, 15 new community solar projects were introduced, and as of September 2014, an additional 14 programs had begun. The capacity of existing community solar projects totals more than 40 MW, with an additional 17 MW of projects under development.
- Wholesale RECs used in the voluntary market traded at around \$1.20/MWh in 2013; this increase from around \$1.00/MWh in previous years may have contributed to the flat growth in the unbundled REC market in 2013.

References

Apple. (2014). “Environmental Responsibility.” Accessed October 24, 2014: https://www.apple.com/environment/.

APX. (2014). Distributed Generation Toolkit for REC Registries. Accessed September 24, 2014: http://www.narecs.com/wp-content/uploads/sites/2/2014/02/DGToolkitforRECRegistries.pdf.

Belyeu, K. (September 3, 2014). Phone interview with Cappadona, M. of Colonial Power Group.

Bird, L.; Kreycik, C.; Friedman, B. (2008). *Green Power Marketing in the United States: A Status Report (Eleventh Edition)*. NREL/TP-6A2-44094. Golden, CO: National Renewable Energy Laboratory. Accessed September 2010: http://www.nrel.gov/docs/fy09osti/44094.pdf.

Bird, L.; Kreycik, C.; Friedman, B. (2009). *Green Power Marketing in the United States: A Status Report (2008 Data)*. NREL/TP-6A2-46581. Golden, CO: National Renewable Energy Laboratory. Accessed October 4, 2011: http://www.nrel.gov/docs/fy09osti/46581.pdf.

Bird, L.; Sumner, J. (2010). *Green Power Marketing in the United States: A Status Report (2009 Data)*. NREL/TP-6A20-4940. Golden, CO: National Renewable Energy Laboratory. Accessed September 2011: http://www.nrel.gov/docs/fy11osti/49403.pdf.

Cape Light Compact. (2014). “Disclosure Label.” Accessed September 15, 2014: http://www.capelightcompact.org/powersupply/disclosurelabel

Campbell, B.; Chung, D.; Venegas, R. (2014). *Expanding Solar Access Through Utility-Led Community Solar: Participation and Design Trends from Leading U.S. Programs*. Washington, D.C.: Solar Electric Power Association (SEPA). http://www.solarelectricpower.org/media/214996/community-solar-report-ver5.pdf.

Chatterjee, K. (2013). “Cleveland and Cincinnati Go Renewable.” World Wildlife Fund. http://www.worldwildlife.org/blogs/on-balance/posts/cleveland-and-cincinnati-go-renewable.

Clean Energy Authority. (2014). “Community-Based Renewable Energy Pilot Program.” Accessed August 19: http://www.cleanenergyauthority.com/solar-rebates-and-incentives/maine/community-based-pilot-program.

Colonial Power Group. (2014). “City of Lowell Becomes First Massachusetts Municipality to Achieve Carbon Neutral Electricity Consumption for the Entire Community.” Accessed September 15, 2014: http://colonialpowergroup.squarespace.com/lowell-carbon-neutral/?SSScrollPosition=342

“Database of State Incentives for Renewables & Efficiency (DSIRE).” (2014). North Carolina State University. Accessed September 19, 2013: http://www.dsireusa.org/.

Department of Energy (DOE)/FEMP. (2014). *Comprehensive Annual Energy Data and Sustainability Performance: A-7 Renewable Electric Energy Use as a Percentage of Total Electricity Use FY 2013*. Accessed October 10, 2014: http://ctsedwweb.ee.doe.gov/Annual/Report/Report.aspx.

Environmental Protection Agency (EPA). (2014). Green Power Partnership National Top 100, Released July 28, 2014. Accessed October 24, 2014: http://epa.gov/greenpower/toplists/top100.htm.

EIA. (2014a). Electric Power Monthly. Washington, D.C.: EIA. Accessed September 2014: http://www.eia.gov/electricity/monthly/pdf/epm.pdf.

EIA. (2014b). "Retail Sales of Electricity, Annual" and "Direct Use of Electricity to Ultimate Customers by Sector, by Provider." Electricity Data Browser. Accessed September 2014: http://www.eia.gov/electricity/data/browser/.

Englum, L.; Chatterjee, K.; Marshall, S.; Medearis, L.; Ronen, A.; Wochos, S. (2014). Leading from the Middle: How Illinois Communities Unleashed Renewable Energy. Washington, D.C.: World Wildlife Fund. Accessed April 7, 2014: http://gocleangolocal.org/wp-content/uploads/2014/03/Leading-from-the-Middle_IL-Report_FINAL.pdf.

Environmental Tracking Network of North America (ETNNA). (2011). "Renewable Energy Tracking Systems." Accessed September 20, 2011: http://www.etnna.org/learn.html.

Farrell, J. (2014). "Greening or Greenwashing? Illinois Cities' Use of RECs Shows Challenges with Local Aggregation." Washington, D.C.: Institute for Local Self-Reliance. http://www.ilsr.org/illinois-cities-greening-or-greenwashing/.

Fisher, J. (2014). "Oak Park ditches all-green power supply; residents can still opt for clean energy." *Oak Leaves*. Accessed September 2014: http://oakpark.suntimes.com/2014/04/18/oak-park-ditches-all-green-power-supply-residents-can-still-opt-for-clean-energy/.

Frederick, Z. (2014). "Developing Strong Green Tariff Shared Renewables Programs for California." *Clean Energy News Blog.* Menlo Park, CA: Clean Coalition. Accessed September 2014: http://www.clean-coalition.org/developing-strong-green-tariff-shared-renewables-programs-for-california/.

Friedman, B.; Miller, M. (2009). *Green Pricing Program Marketing Expenditures: Finding the Right Balance.* NREL/TP-6A2-46449. Golden, CO: National Renewable Energy Laboratory. Accessed October 18, 2013: http://www.nrel.gov/docs/fy09osti/46449.pdf.

Global e-Sustainability Initiative (GeSI). (2012). *GeSI SMARTer 2020: The Role of ICT in Driving a Sustainable Future*. Accessed September 2014: http://gesi.org/assets/js/lib/tinymce/jscripts/tiny_mce/plugins/ajaxfilemanager/uploaded/SMARTer%202020%20-%20The%20Role%20of%20ICT%20in%20Driving%20a%20Sustainable%20Future%20-%20December%202012._2.pdf.

Google. (2014). "Investing in a clean energy future." Accessed May 8, 2014: http://www.google.com/green/ energy/investments/.

Google. (2013a). Google's Green PPAs: What, How, and Why. Accessed May 2014: http://static.googleusercontent.com/external_content/untrusted_dlcp/www.google.com/en/us/green/pdfs/renewable-energy.pdf.

Google. (2013b). Expanding Renewable Energy Options for Companies Through Utility-Offered "Renewable Energy Tariffs." Accessed September 2014: http://static.googleusercontent.com/media/www.google.com/en/us/green/pdf/renewable-energy-options.pdf.

Heeter, J. (October 11, 2014a). Email from Terada, R. of the Center for Resource Solutions, San Francisco, California.

Heeter, J. (August 12, 2014b). Email from Tucker, D. of ERCOT, Austin, Texas.

Heeter, J. (August 26, 2013). Email from Barbose, G. of the Lawrence Berkeley National Laboratory.

Heeter, J.; Armstrong, P.; Bird, L. (2012). *Market Brief: Status of the Voluntary Renewable Energy Certificate Market (2011 Data)*. NREL/TP-6A20-51904. Golden, CO: National Renewable Energy Laboratory. Accessed October 9, 2013: http://www.nrel.gov/docs/fy12osti/56128.pdf.

Heeter, J.; McLaren, J. (2012). *Innovations in Voluntary Renewable Energy Procurement: Methods for Expanding Access and Lowering Cost for Communities, Governments, and Businesses*. NREL/TP-6A20-54991. Golden, CO: National Renewable Energy Laboratory. Accessed October 14, 2013: http://www.nrel.gov/docs/fy12osti/54991.pdf.

Heeter, J.; Bird, L. (2011). *Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data)*. NREL/TP-6A20-52925. Golden, CO: National Renewable Energy Laboratory. Accessed October 9, 2013: http://www. nrel.gov/docs/fy12osti/52925.pdf .

Hodum, R; Molitor, M. (2013). *Power Forward: Why the World's Largest Companies Are Investing In Renewable Energy*. Prepared by David Gardiner & Associates. Washington, D.C.: World Wildlife Fund. Accessed September 2014: http://assets.worldwildlife.org/publications/507/files/original/Power_Forward_FINAL_hi_res.pdf?1357935348.

Kiefaber, A. (2014). "City to continue using green energy." Cincinnati.com. Accessed September 2014: http://www.cincinnati.com/story/news/local/downtown/2014/03/12/green-energy-cincinnati-city-council-brown-energy/6345895/.

Koomey, J. (2011). *Growth in Data Center Electricity Use 2005 to 2010*. Oakland, CA: Analytics Press. Accessed September 2014: http://www.analyticspress.com/datacenters.html.

LeanEnergyUS. (2013). "Rhode Island." Accessed September 2014: http://www.leanenergyus.org/cca-by-state/rhode-island/.

Marex Spectron. (2014). Data accessed through Vantage database. London, UK: Marex Spectron. Accessed October 15, 2014: http://www.marexspectron.com/.

Marin Energy Authority. (2014). "Renewable Energy Procurement." Accessed September 2014: http://marincleanenergy.org/energy-procurement.

Marin Energy Authority. (2013). "Marin Clean Energy Integrated Resource Plan." Accessed September 2014: http://marincleanenergy.org/sites/default/files/key-documents/Integrated_Resource_Plan_2013_Update.pdf.

Massachusetts Department of Public Utilities. (2014). "Open and Closed Municipal Aggregation Dockets." Accessed October 24, 2014: http://www.mass.gov/eea/energy-utilities-clean-tech/electric-power/electric-market-info/open-closed-municipal-aggregation.html.

Microsoft. (2014). "Environment: Our Footprint." Accessed September 2014: http://www.microsoft.com/environment/our-commitment/our-footprint.aspx.

Mosaic. (2014). "Browse Investments." Accessed May 8, 2014: https://joinmosaic.com/browse-investments.

North American Renewables Registry (NAR). (2014). "Inter-Registry Transfers." Accessed September 2014: http://www.narecs.com/resources/registries/

NV Energy. (2014). "Nevada Power's NV GreenEnergy Rider Tariff." Advice Letter No. 440.

Otto, N. (2014). "SB 43: A Primer on California's Foray into Community Shared Solar." Mosaic Blog. Accessed September 2014: https://joinmosaic.com/blog/sb-43-californias-community-shared-solar/.

Prince, J. (2014). NEPOOL Class I RECs: Q1 2014 Data Release Update. July 15. http://www.renewableenergyworld.com/rea/blog/post/2014/07/nepool-class-i-recs-q1-2014-data-release-update?page=all. Accessed August 27, 2014.

Proudlove, A., and Kennerly, J. (2014). Solar PV Deployment through Renewable Energy Tariffs: An Option for Key Account Customers. North Carolina Clean Energy Technology Center. http://nccleantech.ncsu.edu/wp-content/uploads/Solar-Ops-Report-2014-ver5-1.pdf. Accessed November 3.

Solar Energy Industries Association (SEIA) and GTM Research. (2014). *U.S. Solar Market Insight Report: 2013 Year in Review*. Greentech Media, Inc. and SEIA.

Terada, R. (September 23, 2013). Presentation at the 2013 Renewable Energy Markets Conference. Austin, Texas.

Verizon. (2014). “Verizon Plans Major Expansion of Its On-Site Green Energy Program.” Accessed October 24, 2014: http://www.verizon.com/about/news/verizon-plans-major-expansion-its-site-green-energy-program/.

VillagePower. (2014). “Browse Projects.” Accessed October 24, 2014: http://villagepower.com/browse-projects/.

Weiss-Tisman, H. (2014). “More Solar Projects in the Forecast.” *Brattleboro Reformer*. Accessed September 2014: http://www.reformer.com/localnews/ci_25454420/more-solar-forecast.

Xcel Energy. (2014). “Solar*Rewards Community.” Accessed September 16, 2014: http://www.xcelenergy.com/Save_Money_&_Energy/Residential/Renewable_Energy_Programs/Solar*Rewards_Community_-_CO.

Appendix D

LETTERS OF SUPPORT

Excellent health and care for everyone,
everywhere, every time.

island health

June 16, 2015

Jennifer Coulthard
Major Commercial Accounts
Key Account Manager–Healthcare, Hospitals
16705 Fraser Highway
Surrey BC V4N 0E8

Dear Ms Coulthard,

Re: Vancouver Island Health Authorities Support for FortisBC's Application for New Renewable Gas Rate

I am writing on behalf of Island Health to support FortisBC's application for a new renewable gas rate. Island Health is committed to sustainable health care and part of that commitment is to reduce environmental impact and greenhouse gas emissions. On January 1, 2015 Island Health started to purchase a small amount of renewable natural gas for our two largest facilities. We are currently buying 45 GJ/Day of renewable gas and on average 1,308 GJ/ Day of natural gas. This small percentage of total gas helps to show Island Health's commitment to renewable energy and demonstrates that we are willing to be innovative when it comes to sustainability.

Buying renewable gas is a very simple way to quickly reduce greenhouse gas emissions and could be valuable for meeting future reduction targets. Island Health has committed to reduce greenhouse gas emissions 33% below 2007 levels by 2020. Currently reductions through conservation are having an impact but it will not be sufficient to meet the target. Renewable gas could help with this. Unfortunately the current rate of renewable gas is a barrier to increasing the amount purchased. Island Health would consider purchasing more if the rate was lower and could enter into a multi year agreement. The benefit of a stable price not affected by inflationary increases, carbon tax or carbon offsets is appealing

Thank you.

Sincerely,

Deanna Fourt

Deanna Fourt, AScT
Director of Energy Efficiency and Conservation for VIHA

cc: Cecil Rhodes, VIHA Corporate Director Facilities Managementt

Energy Efficiency and Conservation Department
Located at: 1190 Seafield Crescent | Nanaimo, BC V9S 5K5 Canada Tel: 250-740-2675 | Fax: 250-755-3394
Mailing address: 1200 Dufferin Crescent | Nanaimo, BC V9S 2B7 Canada
viha.ca

THOMPSON RIVERS UNIVERSITY
Sustainability Office

May 14, 2015

Vladimir Kostka, MBA
Key Account Manager
BC Educational and Municipal Sectors
BC Recreational Facilities

Fortis BC Inc.
16705 Fraser Hwy
Surrey, BC
V4N 0E8

Dear Mr. Kostka

Re: Thompson Rivers University's support for Fortis BC's application for lower renewable gas rates and longer term agreements.

In 2008 Thompson Rivers University (TRU) identified "Increasing sustainability" as a foundational value and strategic priority. Over the past 5 years energy conservation and reducing Green House Gas (GHG) emissions have been the key areas of focus towards improving operational sustainability. Through extensive retro-fitting, natural gas use and Green House Gas (GHG) emissions have been reduced by more than twenty percent. TRU, however, has a GHG reduction target of 35 percent and purchasing renewable gas is considered an integral component in achieving this goal. The other options to achieve thirty to thirty-five percent GHG reductions, such as district energy or Geo-exchange, have been examined and deemed not feasible for the campus.

In April, 2015 TRU began purchasing ten percent of the total annual natural gas required as renewable gas, on a trial basis. Although this accelerated TRU to a thirty percent reduction in GHG emissions, the cost and terms of the agreement do not allow for considering renewable gas a long term bases. Purchasing renewable gas could become a permanent and larger part of TRU's energy supply portfolio and GHG reduction strategies, if lower prices and multi-year agreements allowed for long term budgeting and planning.

Thank you.

Jim Gudjonson
Director
Thompson Rivers University
Sustainability Office

THE UNIVERSITY OF BRITISH COLUMBIA

UBC Energy & Water Services
Generation & Distribution
Office of the Director
2040 West Mall
Vancouver, BC
V6T 1Z2

Phone: (604) 822-0852
Fax: (604) 822-8833
Paul.holt@ubc.ca
www.buildingoperations.ubc.ca

11th May, 2015

Letter of Support

The University of British Columbia to the BCUC

In this letter UBC will provide some background and perspective so that FortisBC can put forward a meaningful application to the BCUC. UBC will also comment on its future potential demand for RNG as a customer.

Currently UBC purchases 55,000GJ's of RNG annually from FortisBC. RNG is used as the fuel source for a Cogeneration reciprocating engine located at the UBC BioEnergy Research Demonstration Facility (BRDF). UBC has a signed Load Displacement Agreement (LDA) with BCHydro where it is a condition of the LDA that electrical production is from a green or biofuel source i.e. RNG. Therefore, UBC has long term interest in the steady supply, availability and pricing for RNG.

For approximately 18 months, UBC understood that pricing for RNG was $11.69 per GJ based on the posted rate. Further, UBC believed this to be an 'all-in' price for RNG. At this price the conversion of the BRDF engine to a dual fuelled machine of either RNG or Syngas was approved.

Since the dual fuel engine conversion, two significant price rises impacted UBC:

1. The 2013 year end BCUC decision which changed cost allocation requiring that additional costs such as admin and advertisement costs be passed to RNG customers only. This decision along with higher than expected supply costs for FortisBC resulted in a change from $11.69/GJ to $14.06/GJ - a $2.37/GJ commodity rate increase.
2. FortisBC had not clearly communicated to UBC that RNG would still be subject to transport costs. This oversight effectively added another $2.34/GJ for transport + taxes to UBC costs.

UBC from a pricing perspective looks at the all in cost and not just commodity price, therefore transport costs are also a crucial price inclusion for consideration.

The impact to UBC from both measures was to increase the cost of RNG to UBC from $11.69/GJ to $16.40/GJ all in cost, a $4.71/GJ price increase. Due to the revised price for RNG, UBC has scaled back its purchase of RNG (originally at 96,000 GJ's per annum) to the minimum amount for FY 15/16 that is mandatory to satisfy and maintain the LDA i.e. 55,000GJ RNG per annum. For FY 14/15, UBC incurred an additional cost for RNG of $222k due to the unanticipated increases in RNG pricing. This price exposure would have been significantly worse if UBC had not scaled back its RNG purchase.

It should be noted that buying NG + Transport+ Carbon Tax + Carbon Offsets is currently 50% the price of RNG per GJ and under this pricing it is difficult the see how any business case would support making the transition to RNG.

Should RNG pricing fall by a significant value, then UBC's may reconsider increasing its purchase of RNG to work back towards the original planned volume of 96,000GJ's per annum.

UBC holds a 15 year LDA agreement with BCHydro, so UBC would have an active interest to look towards a long term fixed price schedule or multiyear contract. However, for this to be possible there would have to be a significant reduction in current pricing. FortisBC and UBC have had some preliminary discussions as to what this may look like ranging from:

a) A levelized or fixed rate for 10 years e.g. $?/GJ 'all in cost', with no price rise annual escalation.
b) A lower start commodity price e.g. $Average NG + $2.75 (Carbon Tax & Offset)/GJ, but with a fixed annual escalator e.g. 1 or 2% over 10 years to recover costs.

UBC is reviewing a potential large scale Cogeneration project (phase 2) to supplement the new UBC Campus Energy Center (CEC) (phase 1), currently under construction at UBC. This Cogeneration project would require up to 1,000,000GJ's RNG annually, if approved. The present day RNG price adversely impacts this project, such that it has not made it beyond the schematic development stage. Were UBC to proceed with a cogeneration facility it would have an active interest in a long term fixed price schedule/ multiyear contract for up to 1,000,000 GJ's of RNG.

UBC has been, and is an active supporter of the RNG program. UBC was instrumental in aiding FortisBC gain acceptance by the BC Ministry of Communities and the BC Climate Action Secretariat (BCCAS) for RNG to be included into the BC Climate Action Toolkit or SMARTTool register. Additionally UBC worked extensively with BCHydro to now accept RNG as a viable biofuel source as part of BCHydro' s Standing Offer Program for clean & renewable electrical production.

Paul Holt

Paul Holt CEng
Director, Generation & Distribution
UBC

CanGAZ Ventures Inc.
5799 Ryder Lake Road
Chilliwack, BC, Canada
V4Z 1E2

March 26, 2015

FortisBC
16705 Fraser Highway
Surrey, BC
V4N 0E8

Attention: Neil Dobson, Energy Solutions Manager

RE: Renewable Natural Gas Pricing Comments

I am writing to present my company's view of affordable renewable natural gas (RNG) pricing for a 15MW power project that was proposed to be built on a site in Surrey, BC. The site and project evaluation were conducted from April to December 2014. In December, BC Hydro's policies shifted under SOP and were clarified such that the project was non-viable as it no longer qualified under SOP.

The project's financial model indicated a viable RNG price range from $8.00 CAN to $12.00 CAN per GJ. The range of pricing was a function of potential ancillary revenue to the project and the required return on investment to the project's funding sources. Ancillary revenues included the projected sale of heat, CO2 and heat related carbon credits. To the extent that those ancillary revenues could be realized the plant would have been able to pay in the range of $12.00 CAN per GJ for BC originated RNG.

The project would have required an estimated 1.1 million GJ per year of RNG. It was projected to become operational in 2017. An imported supply of RNG was considered as locally the existing supply of RNG and the projected local supply of RNG was limited and priced too high for project viability. If BC Hydro's policies had supported a project of this nature a 25 year electricity purchase agreement would have been most suitable.

Additional aspects of viability included an RNG exchange where RNG throughout North America could have been traded. The BC Carbon Tax exemption was a significant factor and CanGAZ would have attempted to negotiate pricing from FortisBC that did not include a cost associated with "residential education" for BC originated RNG.

The multi-project and multi-year mandate that CanGAZ has was to develop at least three RNG power plants but BC RNG pricing and electricity purchase policies, in my view have not yet evolved sufficiently for such projects to be viable at this time. The change in BC Hydro's SOP policies at the last moment assured a no go outcome.

Without suitable electricity purchase agreements and without suitable RNG pricing, the opportunities to develop biogas projects including biogas production will remain stalled in BC. Specifically, if RNG pipeline gas is not accepted in BC when it is accepted throughout North America then projects are limited in location and scale. Those limitations make the associated electricity production and interconnection costs uneconomic. As well the use of blended gas should be considered so that local supply of RNG can be stimulated.

Please contact the writer for any required clarifications of this communication.

Yours,
CanGAZ Ventures Inc.

David R. Irwin, President
Ph: 604-847-9886

Appendix E

FINANCIAL ANALYSIS

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	Total
1	**Biomethane Variance Account**							
2	Opening Balance (after tax)	$ 1,364	$ 1,490	$ 2,821	$ 7,515	$ 15,474	$ 20,903	
3	Additions - Tax Effected							
4	Cost of Biomethane	1,999	3,349	7,122	10,845	12,597	14,402	
5	Operating and Maintenance Expense	618	959	1,644	1,919	1,980	2,043	
6	Property Tax Expense	13	20	20	21	24	28	
7	Earned Return - Debt Component	251	273	301	902	911	919	
8	Subtotal	2,880	4,600	9,087	13,686	15,513	17,392	
9	Tax Offset	(749)	(1,196)	(2,363)	(3,558)	(4,033)	(4,522)	
10	Total Additions - Tax Effected	2,131	3,404	6,725	10,128	11,480	12,870	
11	Additions - Non-Tax Effected							
12	Depreciation	133	361	387	1,161	1,200	1,239	
13	Negative Salvage Provision Expense	-	-	3	4	5	6	
14	Notional Income Tax	(700)	(276)	(24)	(635)	(1,187)	(288)	
15	Earned Return - Equity Component	233	253	279	835	844	851	
16	Subtotal	(334)	338	645	1,365	862	1,808	
17	Total Additions	1,798	3,742	7,370	11,493	12,342	14,679	
18								
19	BERC Recoveries	(2,260)	(1,880)	(2,166)	(2,371)	(2,575)	(2,784)	
20	Tax Offset	588	489	563	617	669	724	
21	Net Recoveries	(1,672)	(1,391)	(1,603)	(1,755)	(1,905)	(2,060)	
22								
23	Aged inventory write-off - non-tax effected	-	-	-	(1,074)	(3,310)	(4,972)	***(9,356)***
24	Tranfer all costs except Supply ending balance	-	(1,019)	(1,074)	(705)	(1,697)	(9,100)	***(13,595)***
25								
26	**BVA Closing Balance (after tax)**	**$ 1,490**	**$ 2,821**	**$ 7,515**	**$ 15,474**	**$ 20,903**	**$ 19,449**	
	(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
1	**BERC Recoveries/Sales**						
2	**Rate 1:** Residential Volume (GJ)	68,058	74,162	86,459	97,966	108,455	120,317
3	BERC Rate $ /GJ	$ 14.414	$ 11.330	$ 11.467	$ 11.600	$ 11.765	$ 11.926
4	Recovery from Residential ($000)	$ 981	$ 840	$ 991	$ 1,136	$ 1,276	$ 1,435
5							
6	**Rate 2:** Small Commercial Volume	5,390	6,173	6,829	7,121	7,358	7,595
7	BERC Rate	$ 14.414	$ 11.330	$ 11.467	$ 11.600	$ 11.765	$ 11.926
8	Recovery from Small Commercial ($000)	78	70	78	83	87	91
9							
10	**Rate 3:** Large Commercial Volume	6,449	6,822	7,330	7,554	7,635	7,703
11	BERC Rate	$ 14.414	$ 11.330	$ 11.467	$ 11.600	$ 11.765	$ 11.926
12	Recovery from Large Commercial ($000)	93	77	84	88	90	92
13							
14	**Other On-System Volume (Gas marketer)**	6,716	7,052	7,404	7,775	8,163	8,572
15	BERC Rate	$ 14.414	$ 11.330	$ 11.467	$ 11.600	$ 11.765	$ 11.926
16	Recovery from Other On-System ($000)	97	80	85	90	96	102
17							
18	**Transportation Sector/CNG**	-	1,172	2,000	3,000	5,000	5,765
19	BERC Rate	$ 14.414	$ 11.330	$ 11.467	$ 11.600	$ 11.765	$ 11.926
20	Recovery from Other Off-System ($000)	-	13	23	35	59	69
21							
22	**Large/Fixed Volume / Cogen**	70,180	77,425	86,388	88,638	89,888	91,138
23	BERC Rate	$ 14.414	$ 10.330	$ 10.467	$ 10.600	$ 10.765	$ 10.926
24	Recovery from Other Off-System ($000)	1,012	800	904	940	968	996
25							
26	Total Sales Volumes (GJ)	156,793	172,806	196,410	212,054	226,499	241,090
27	**Total Recoveries ($000)**	$ 2,260	$ 1,880	$ 2,166	$ 2,371	$ 2,575	$ 2,784

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	$ -	$ -	$ 346,345	$ 1,013,751	$ 1,451,287
4	Forecasted Natural Gas Commodity rate	$ 2.83	$ 2.97	$ 3.10	$ 3.27	$ 3.43
5	Aged inventory transfer - non-tax effected ($000)	-	-	(1,074)	(3,310)	(4,972)
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	(1,019)	(1,074)	(705)	(1,697)	(9,100)
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**	$ (0.0058)	$ (0.0061)	$ (0.0040)	$ (0.0097)	$ (0.0519)
18	IMPACT % of delivery margin	0.14%	0.15%	0.10%	0.24%	1.26%
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 $000	2016 TJ	2017 $000	2017 TJ	2018 $000	2018 TJ	2019 $000	2019 TJ	2020 $000	2020 TJ	Notes
1												
2	**Forecast BVA Balance - Deficit at December 31**											
3	**Cost (BVA ending balance pre tax)**	$ 2,013		$ 3,812		$ 10,155		$ 20,910		$ 28,247		
4	**Quantity unsold end of year**		101.66		246.05		647.76		1,315.16		1,752.70	Unsold Quantity
5												
6	**Forecast Costs Incurred in the 12 month period**											
7	**Cost (Jan 1 to Dec 31 costs incurred)**	$ 4,938		$ 9,733		$ 15,051		$ 16,375		$ 19,201		
8	**Quantity (Jan 1 to Dec 31 purchases)**		317.20		598.12		879.46		1,010.38		1,132.95	Purchase Quantity
9												
10	**Biomethane Available for Sale in the 12-month period**											
11	**Total Cost to be recovered**	**$ 6,951**	**418.85**	**$ 13,545**	**844.17**	**$ 25,206**	**1,527.22**	**$ 37,286**	**2,325.54**	**$ 47,448**	**2,885.65**	
12	**Total Quantity**											
13												
14	**Cost-Based BERC Rate**		**$ 16.60**		**$ 16.05**		**$ 16.50**		**$ 16.03**		**$ 16.44**	
15			2016 rate		2017 rate		2018 rate		2019 rate		2020 rate	

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

Schedule 5

	2016	2017	2018	2019	2020	Total	5 year AVERAGE
1 - STATUS QUO Forecast (Escalating upward) Contract Demand Scenario ($16 to $17 BERC used for sales)							
BVA Closing Balance (after tax)	$ 3,464	$ 9,208	$ 19,088	$ 29,838	$ 42,928		
per GJ					$ 0.2449		
BERC RATE based on cost of service	$ 16.60	$ 16.51	$ 16.98	$ 16.86	$ 16.97		
Customer impact based on 90 GJS					**$ 22.04**		
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)	$ 3,464	$ 9,208	$ 9,988	$ 5,834	$ 4,765		
BERC RATE based on cost of service	$ 16.60	$ 16.51	$ 16.98	$ 11.94	$ 9.12		
Stale dated write-off > 18 months old	-	-	(1,661.45)	(4,201.84)	(5,597.11)	**(11,460)**	
per GJ to MCRA	-	-	(0.0134)	(0.0339)	(0.0451)		(0.0185)
Difference between the average cost of supply and CCRA rate	-	-	(7,438.31)	(11,166.23)	(9,296.76)	**(27,901)**	
per GJ - all delivery	-	-	(0.0424)	(0.0637)	(0.0530)		(0.0318)
Customer impact based on 90 GJs							**$ 4.53**
3 - PROPOSED - Lower Price Contract Demand Scenario (CCRA + $7.50/$8.50 BERC used for sales)							
BVA Closing Balance (after tax)	$ 2,821	$ 7,515	$ 15,474	$ 20,903	$ 19,449		
BERC RATE based on cost of service	$ 16.60	$ 16.05	$ 16.50	$ 16.03	$ 16.44		
BERC RATE CHARGED to Customers	$ 11.33	$ 11.47	$ 11.60	$ 11.77	$ 11.93		
BERC RATE CHARGED to Customers Long Term	$ 10.33	$ 10.47	$ 10.60	$ 10.77	$ 10.93		
Stale dated write-off > 18 months old	$ -	$ -	$ (1,074)	$ (3,310)	$ (4,972)	**(9,356)**	
per GJ to MCRA	-	-	(0.0087)	(0.0267)	(0.0401)		(0.0151)
Tranfer all costs except Supply ending balance	(1,019.0)	(1,074.0)	(705.0)	(1,697.0)	(9,100.0)	**(13,595)**	
per GJ - all delivery	(0.0058)	(0.0061)	(0.0040)	(0.0097)	(0.0519)		(0.0155)
Customer impact based on 90 GJS							**$ 2.75**
4 - Green Portfolio							
BVA Closing Balance (after tax)	$ 4,897	$ 11,926	$ 23,072	$ 35,061	$ 49,378		
Impact to customers	$ 0.0395	$ 0.0567	$ 0.0899	$ 0.0967	$ 0.1154		$ 0.0796
Customer impact based on 90 GJS							**$ 7.17**

Appendix F

DRAFT ORDER

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Energy Inc.
For Approval of Biomethane Energy Recovery Charge Rate Methodology

BEFORE:

(Date)

WHEREAS:

A. On December 11, 2013, the British Columbia Utilities Commission (Commission) approved the continuation of the FortisBC Energy Inc. (FEI) Biomethane Program on a permanent basis.

B. On September 14, 2014, the Commission issued Letter L-51-14, accepting the third quarter 2014 Biomethane Variance Account (BVA) Report and that the Biomethane Energy Recover Charge (BERC rate) remain unchanged, and the Commission acknowledged that work would commence on guidelines and criteria for a mechanism for evaluating when a BERC rate change is warranted;

C. On August 28, 2015, FEI filed the BERC Rate Methodology Application, pursuant to sections 59-61 of the *Utilities Commission Act* (the Act);

D. In the Application, FEI requests the following approvals:

    1. Approval of a Short Term Contract BERC rate at the Commission approved January 1st Commodity Cost Recovery Charge (CCRA rate) per GJ, plus the current Carbon Tax applicable to natural gas customers, plus a premium of $7.00 per GJ; and, applicable to all affected biomethane rate schedules within the Mainland, Vancouver Island and Whistler Service Areas, to be effective the later of the start of the first quarter after the Commission's Decision or January 1, 2016 as discussed in Section 7 of the Application;

2. Approval that the Long Term Contract BERC rate be set at a $1.00 per GJ discount to the Short Term Contract rate;

3. Approval to discontinue the quarterly BERC and BVA report and replace with a single report in conjunction with the Fourth Quarter CCRA & Midstream Commodity Reconciliation Account (MCRA) report;

4. FEI may apply to transfer unsold biomethane supply that is greater than 18 months in age and/or 250,000 GJs in the BVA to the MCRA at the prevailing CCRA rate on January 1 each year; and,

5. Approval to amortize the forecast December 31 balance in the BVA, net of the transfer of unsold inventory and remaining supply costs, through the delivery rates of all non-bypass customers effective January 1 of the subsequent year.

E. The Commission has reviewed the Application determined that approval is warranted.

NOW THEREFORE the Commission orders as follows:

1. The Short Term Contract BERC rate is approved at the Commission approved January 1st CCRA rate per GJ, plus the current Carbon Tax applicable to natural gas customers, plus a premium of $7.00 per GJ; and, applicable to all affected biomethane rate schedules within the Mainland, Vancouver Island and Whistler Service Areas, to be effective the later of the start of the first quarter after the Commission's Decision or January 1, 2016.

2. The Long Term Contract BERC rate is approved at a $1.00 per GJ discount to the Short Term Contract rate.

3. FEI is directed to discontinue the quarterly BERC and BVA reports and replace with a single report in conjunction with the Fourth Quarter CCRA and MCRA report.

4. FEI may apply for approval to transfer unsold biomethane supply that is greater than 18 months in age and/ or 250,000 GJs in the BVA to the MCRA at the prevailing CCRA rate on January 1 each year.

5. FEI is directed to amortize the forecast December 31 balance in the BVA, net of the transfer of unsold inventory and remaining supply costs, through the delivery rates of all non-bypass customers effective January 1 of the subsequent year.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 2015.

BY ORDER