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April 7, 2017

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

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Project No. 3698899

2016 Rate Design Application (the Application) - Errata

On December 19, 2016, FEI filed the Application referenced above. FEI has identified several items in the Application that require a correction. The changes made are to address typographical errors and do not change approvals sought.

Description	Revised Pages
Application, Section 1.6	Pages 1-7 and 1-8
Application, Section 2.2	Page 2-4
Application, Section 3.3	Page 3-8
Application, Section 3.3.7	Page 3-13
Application, Section 7.5.3	Page 7-19
Application, Section 11.3.2	Page 11-28
Appendix 4-4	Pages 1, 4, 5, 6, and 9

For ease of identification of the revisions made, FEI has provided all revised pages from Volume 1 (Application) and Appendix 4-4 blacklined for ease of reference.

If further information is required, please contact Richard Gosselin at (604) 576-7178.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

1.5 *COMMERCIAL RATE DESIGN: ALIGNING INTRA-CLASS RATE ECONOMICS*

FEI reviewed the rate design for its small commercial customers taking service under RS 2, RS 2U, RS 2X and RS 2B[7] (collectively referred to as RS 2), and large commercial customers that take service under RS 3, RS 3U, RS 3X, RS 3B[8] (collectively referred to as RS 3) and RS 23. FEI's review of the rate design considered the potential rate structure options for commercial customers (i.e., flat, declining or inclining block), customer segmentation, fixed and volumetric charges and intra-class rate economics.

Based on the analysis of the existing rate design and rate structure options for commercial customers, FEI is proposing the continuation of a flat rate structure and a 2,000 GJ per year customer segmentation threshold for its commercial customers in RS 2 and RS 3/RS 23. The existing flat rate structure and customer segmentation are consistent with other jurisdictions and in line with customer load characteristics. However, the rates for RS 2 and RS 3/RS 23 need minor adjustments to minimize the rate inequity for customers close to the 2,000 GJ threshold. FEI proposes to increase the Basic Charges for RS 2 and RS 3/RS 23, to reduce the Delivery Charge of RS 2 and increase the Delivery Charge of RS 3 and RS 23 to eliminate the customer bill differential for customers whose annual consumption is close to the 2,000 GJ threshold.

1.6 *INDUSTRIAL RATE DESIGN: UPDATING RATES IN ACCORDANCE WITH COST CAUSATION*

FEI reviewed the rate design for its industrial rate schedules (RS 4, RS 5/RS 25, RS 7/RS 27, and RS 22, and large industrial contract customers). FEI identified rate design issues, considered options to resolve those issues and has made proposals based on the best balance of competing principles in the context of each rate schedule.

Deleted: FEI's review of the rate design considered the potential rate structure options for residential customers (i.e., flat, declining or inclining block) and the possible blends of fixed and volumetric charges.

FEI's General Firm Service (RS 5 and RS 25) is designed to serve process load customers with efficient utilization of the system. For this reason, RS 5 and RS 25 have a Demand Charge designed to provide lower average rates to higher load factor customers. Based on peak daily consumption information that was not available when the RS 5 and RS 25 Demand Charge was

[7] The differences in RS 2, RS 2U, RS 2X and RS 2B pertain to the commodity portion of residential rates. In all cases, the transportation and storage service (midstream service) and the delivery service are provided by FEI. Under RS 2, customers receive conventional natural gas from FEI as their commodity. Under RS 2U, customers receive their commodity from a licensed natural gas marketer. In the event that there is a marketer failure, customers that had been served by a marketer under RS 2U may be served under RS 2X. Under RS 2B, customers receive commodity service from FEI, but have elected to receive a percentage of their natural gas as renewable natural gas (biomethane) with the balance being conventional natural gas.

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[8] The differences in RS 3, RS 3U, RS 3X and RS 3B pertain to the commodity portion of large commercial rates. In all cases the transportation and storage service and the delivery service are provided by FEI. Under RS 3, customers receive conventional natural gas from FEI as their commodity. Under RS 3U, customers receive their commodity from a licensed natural gas marketer. In the event that there is a marketer failure, customers that had been served by a marketer under RS 3U, may be served under RS 3X. Under RS 3B ,customers receive commodity service from FEI, but have elected to receive a percentage of their natural gas as renewable natural gas (biomethane) with the balance being conventional natural gas.

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originally designed, FEI is proposing to update the multiplier in the peak day demand formula from 1.25 to 1.1 (the multiplier estimates the peak day demand from the average peak Monthly demand). As a result of the above change, FEI is also proposing to raise the Demand Charge for RS 5 and RS 25 by $3.00/GJ/Month to continue to provide a price signal for only high load factor customers to take General Firm Service.

RS 7 and RS 27 are for interruptible service. The RS 7 and RS 27 charges are set at a discount from firm service. The existing discount achieves a reasonable balance between maximizing the economic value of interruptible service, which helps to offset utility costs to firm customers, and providing a sufficient incentive for existing customers to stay on interruptible service and to attract new customers. FEI is therefore proposing to retain the current interruptible service rate structure and the method of calculating RS 7 and RS 27 Delivery Charges based on a discount from RS 5 and RS 25. FEI is proposing to update the RS 7 and RS 27 Delivery Charge calculation to reflect the change in the Daily Demand formula, including a 62.5% firm service load factor assumption and a 90.9% load factor discount.

For seasonal customers, FEI is proposing to maintain the existing rate structures and methodology to derive the RS 4 Delivery Charges. Since the RS 4 Delivery Charges are based on RS 5 and RS 7, FEI is proposing to update the RS 4 Delivery Charges to reflect the proposed changes to RS 5 and RS 7.

FEI's large industrial customers take service under RS 22, RS 22A, RS 22B, or individual contracts (the Vancouver Island Gas Joint Venture (VIGJV) and BC Hydro Island Generation (BCH IG)). FEI's existing rates are currently separated by geographical regions and there is no postage stamp, cost-based firm rate. FEI is proposing to continue to grandfather RS 22A and RS 22B as closed service offerings due to their unique characteristics. For all other large industrial customers, FEI is proposing to create a firm rate under RS 22 based on a cost allocation from the COSA model. This firm rate would be available for all large industrial customers, including VIGJV and BCH IG when their contracts expire. Under this option, Tariff Supplement G-21 for Creative Energy would be terminated and the contract for BCH IG would be included as a tariff supplement at their current rates. The RS 22 interruptible Delivery Charge is proposed to be set at the effective average cost per GJ of the firm rate.

1.7 *TRANSPORTATION SERVICE RATE DESIGN: TIGHTENING BALANCING RULES CONSISTENT WITH INDUSTRY PRACTICE*

FEI's transportation service is available to large commercial and industrial customers on FEI's system who source their own gas, either from a shipper agent or on their own, and have the gas delivered directly to FEI's system.

The transportation service model is generally working well. As such, FEI does not believe that significant changes are required. However, given industry improvements in monitoring, communicating, and implementing gas balancing, FEI is proposing changes to require transportation customers to balance their gas supply more tightly. In particular, FEI is proposing

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- For RS 23:
  - Decrease the Administration Charge per Month from $78.00 to $39.00, set out in Appendices 11-3 and 11-4, and to be discussed in the supplemental filing to the Application to be filed February 2, 2017.

4. Approval of proposed housekeeping and other amendments to Rate Schedules 2, 2U, 2X, 2B, 3, 3U, 3X, 3B, and 23, as set out in Appendix 11-3, and to be discussed in the supplemental filing to the Application to be filed February 2, 2017.

Industrial Rate Schedules

5. Approval to revise the multiplier in the Daily Demand formula in RS 5 and RS 25 from 1.25 to 1.10 and to increase the Demand Charge in RS 5 and RS 25 by $3.00/GJ/Month, as discussed in Section 9.5.
6. Approval to decrease the Delivery Charge of RS 7 and RS 27 by $0.012/GJ as shown in Table 9-20 and discussed in Section 9.6.
7. Approval to increase RS 4 rates due to the proposed changes to RS 5 and RS 7 as shown in Table 9-21 and discussed in Section 9.7, by increasing the Off-Peak Delivery Rate by $0.114/GJ and by decreasing the Extension Period by $0.018/GJ.
8. Approval to set the charges for RS 22 on a cost of service basis for all large industrial customers, as discussed in Section 9.8.5, as follows:
   - Firm Demand Charge of $25.000/GJ/Month.
   - Firm MTQ Delivery Charge of $0.15/GJ.
   - Interruptible MTQ Delivery Charge of $0.972/GJ.
9. Approval to terminate Tariff Supplement G-21, FEI's contract with Creative Energy Vancouver Platforms Inc., effective June 1, 2018, as discussed in Section 9.8.5 of the Application.
10. Approval of adjustments to the transportation model as follows:
    - Amendments to Rate Schedules 22, 22A, 22B, 23, 25, 26, and 27 to implement daily balancing for all transportation customers, as discussed in Section 10.6.
    - Amendments to Rate Schedules 22, 22A, 22B, 23, 25, 26, and 27 to reduce the daily balancing tolerance to a 10% threshold and to introduce a balancing charge of $0.25/GJ for transportation customers for gas supply shortfalls within a 10% to 20% tolerance level, as discussed in Section 10.7.
11. Approval of proposed housekeeping and other amendments to Rate Schedules 5, 7, 11B, 14A, 22, 22A, 22B, 25, 26, and 27 as set out in Appendices 11-3 and 11-4, and to be discussed in the supplemental filing to the Application to be filed February 2, 2017, including, but not limited to, the following:

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Table 3-3: FEI Rate Design Approved Methodologies

Application	Key Rate Design Methodologies Approved
1991 Phase A Rate Design	• Gas cost allocation methodology to address the deregulation of the gas supply environment. • Development of regional gas cost rates for sales customers in each of the Lower Mainland, Inland and Columbia service areas.
1992 Revenue Requirement Application and Negotiated Settlement Process	• The creation of a GCRA.
1993 Phase B Rate Design	• Development of postage stamp Basic Charge and delivery rate structures for firm sales and transportation customers (with the exception of RS 22A and the Columbia division) while maintaining regional large industrial rate structures.
1994/95 Revenue Requirement Application	• Revenue decoupling mechanism called the Revenue Stabilization Adjustment Mechanism (RSAM).[23]
1996 Rate Design	• Underlying postage stamp approach maintained. • Rebalancing of residential and large industrial rates as a result of a negotiated settlement process. • Basic charges were raised to more closely align with fixed costs.
1996/97 Revenue Requirement Application	• Modifications to the RSAM.[24]
2000 Southern Crossing Pipeline Cost Allocation	• On an interim basis Commission approved recovery of SCP costs in the Delivery Margin from all non-Bypass customers, but excluding RS 22B and Fort Nelson customers (Order G-74-00). • NSA parties agreed to the principle that customers that benefit from SCP should contribute to the cost recovery • The accounting treatment of SCP and allocation of SCP costs were deferred to the 2001 Rate Design Application.[25]
2001 Rate Design	• Underlying postage stamp approach maintained. • Rebalancing of residential and large industrial rates as a result of a negotiated settlement process. • Residential basic charges were increased to improve alignment with fixed costs. • To achieve an economic break point between RS 2 and RS 3/RS 23 that approaches the 2,000 GJ/year threshold, the commercial customer basic charges were increased. • Increases in basic charges were offset by corresponding decreases in delivery charges to maintain the revenue neutrality.

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[23] Commission Order G-59-94, dated August 4, 1994.
[24] Commission Order G-99-95, dated November 27, 1995.
[25] Commission Order G-75-00, dated July 27, 2000.

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3.3.6 2001 Rate Design Application

In August 2000, the Commission directed[38] BC Gas to file another rate design application, which was filed on February 5, 2001. The focus of the 2001 Rate Design Application was the allocation of costs associated with newly completed capital projects[39] prior to 2001. The 2001 Rate Design Application addressed three main issues:

1. The level of rates between classes, or revenue realignment;
2. The structure of existing rate classes; and
3. Revisions required to the General Terms and Conditions, particularly for transportation customers.

At the request of participants of a workshop and prehearing conference, the Commission retained an independent rate design consultant, EES Consulting, to review the 2001 COSA study. EES Consulting was tasked with validating the COSA model and assessing the extent to which BC Gas' Cost of Service methodology corresponded to generally accepted rate setting practices. This EES Consulting review verified the validity and robustness of the COSA study.

The 2001 Rate Design Application was the subject of an NSP and the resulting settlement document was approved by Commission Order G-116-01. The approved settlement document included minor changes to the rate schedules.

3.3.7 Commodity Unbundling Applications (Customer Choice Program)

Natural gas commodity unbundling (i.e., the Customer Choice Program) was part of the 2002 Provincial Energy Policy which indicated that natural gas marketers would be permitted to sell directly to low-volume customers, and would be licensed in order to provide consumer protection. In response to this policy, the Commission directed BC Gas to update and reassess its unbundling program.[40] In 2003, the Commission subsequently directed that unbundling for small volume customers should be implemented in two phases:[41]

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1. Commercial customers were to have an unbundled option effective November 2004 (Phase 1);
2. Residential customers in the second phase at some point in the future (Phase 2).

As the first step of the unbundling process, the business rules of the Customer Choice Program were defined by the ESM, which was approved by the Commission in 2003.[42] Under the ESM,

[38] Commission Order G-75-00, dated August 4, 2000.

[39] 2001 Rate Design Application filed with the Commission February 5, 2001, p.1: "With regard to the total cost of service, a significant change is the addition of a number of major capital projects to the infrastructure supporting the gas utility. The most notable among these is the Southern Crossing Pipeline (SCP) project; others include the IBIS financial management system, the Mercury billing system, and new buildings and facilities."

[40] Commission Letter L-49-02 dated December 13, 2002.

[41] Commission Letter L-14-03, dated April 16, 2003.

[42] Appendix A to Commission Letter L-25-03, dated June 6, 2003.

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affect customers' behaviour through decreased customer participation in energy saving activities rather than a direct increase in consumption. That is, the customer may lose the incentive to achieve the desired level of energy savings.

In light of government's energy policy considerations, any increase in the Basic Charge should be done in a manner that does not discourage customers' engagement in energy saving initiatives. As such, a complete alignment between fixed costs and fixed charges is not desirable from an energy conservation and efficiency perspective.

7.5.3 Proposed Change in Basic Charge and Volumetric Delivery Charges

The discussion above demonstrates that there are competing factors both for and against increasing the Basic Charge. Factors in favour of increasing the Basic Charge are:

- the fairness argument (Sections 7.3 and 7.5.1); and
- the evidence that other Canadian gas utilities have a higher percentage of cost recovery through a basic charge (Section 7.6).

The factors that mitigate against making significant changes to the Basic Charge are:

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- the government energy efficiency and conservation policies (Section 7.5.2)
- bill impacts and rate stability for residential customers; and
- the feedback received from participants in FEI's Rate Design and Segmentation workshop (where there was no strong support for a change in the Basic Charge and the volumetric Delivery Charge).

In order to achieve a reasonable balance among competing rate design considerations, FEI is proposing a moderate one-time 5% increase in the Basic Charge and a corresponding decrease in the volumetric Delivery Charge.

The bill impact and rate analysis for this proposal that is included in Section 7.8 of this Application demonstrates that a 5% increase leads to only a +/-1% annual bill impact for the majority of customers and a zero bill impact for an average use customer. In addition, a one-time 5% increase in the Basic Charge is not significant enough to discourage customers from engaging in energy savings activities. This is because a significant portion of FEI's costs continue to be recovered through volumetric charges and FEI proposes that future revenue requirement increases will continue to be allocated to the volumetric Delivery Charge.

7.6 *JURISDICTIONAL COMPARISON OF RATES*

FEI retained the services of EES Consulting to review the applicable rate structures for residential customers in other major Canadian provinces. The summary results of this study are

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Table 11-6: Update to OH&M Charge Calculation

	Forecast 2016	Forecast 2017	Total
Staff Resources ($000)	747	769	1,516
Customer Education ($000)	70	60	130
Total Overhead ($000)	817	829	1,646
Projected Volumes (TJ)	1,196	1,702	2,898
Annual Charge ($/GJ)	0.68	0.49	0.57

Using the 2016 and 2017 forecast volumes from the FEI Annual Review for 2017 Rates, Evidentiary Update filed October 5, 2016, the OH&M charge calculation in Table 11-6 results in $0.57/GJ. Given that the OH&M charge is dependent on forecast volumes which will vary from actual volumes, and because the term of the GGRR extends further than 2017 (to 2022), FEI expects this amount will decrease over time. FEI continues to update its forecasts for the remaining term of the GGRR and believes that the current levels of overhead and volumes continue to support the $0.52 OH&M charge.

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11.3.3 Conclusion

Based on FEI's review and the updated calculation, FEI recommends the OH&M charge for CNG and LNG fueling station customers remain unchanged at $0.52/GJ.

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Appendix 4-4

MARGINAL COST STUDY

ERRATA, DATED APRIL 7, 2017

Executive Summary

This report is provided to Fortis Energy, Inc. (FEI) in support of its 2016 Rate Design Application (RDA). EES Consulting has provided assistance to FEI throughout the process by providing a assistance with COSA and rate design analysis. As part of that assistance, EES Consulting looked at the marginal cost of delivering natural gas for FEI.

The marginal cost analysis developed for FEI is based on appropriate methodologies and takes into account standard practice as well as analysis previously approved by the Commission. Two methods were developed to determine the marginal cost of gas for FEI. The first approach relies on the Rate Impact Analysis (RIA) used for FEI's 2015 System Extension Application. The second approach relies on the results of the 2014 LTRP.

The RIA looked at the total cost to the utility divided by the total system use in GJ with and without the inclusion of 7 years' worth of customer additions. The analysis included all of the capital costs associated with connecting new customers to the system, including meters & regulators, services and mains. Based on this capital amount and the growth in customers, annual costs were calculated and included O&M, return, depreciation and taxes. The RIA shows a marginal cost of $3.~~7~~37 per GJ, which is 19% below the average system cost for the 2015 revenue requirement. This estimate is appropriate only in the case where sales are based on the addition of new customers and reflects a medium time frame.

To develop the long-run marginal cost for delivery service for FEI, the costs associated with the facilities identified in the 2014 LRTP were considered along with the projected growth on the system. In this case the only item identified was the Okanagan Reinforcement Project. Planning for the 2017 LTRP is currently underway and based on that planning this project has been deferred to a 2020 time frame and a rough estimate of the cost is $140 million. The levelized cost included the O&M, return, depreciation, property taxes and income taxes associated with the project. The resulting long-run marginal cost is $0.20 for the system overall and is based on a 20-year planning horizon. This amount is appropriate for growth in GJ from existing customers.

For the long-run cost associated with growth from new customers, the total system levelized cost of $0.20 would need to be added to this $3.3~~7~~7 per GJ resulting from the RIA. The result in this case is still below the average embedded cost of delivery service.

In both cases the marginal cost is well below the average embedded cost of gas delivery. This would indicate that costs for all customers will be lower as a result of growth in sales and/or customers on the system. In terms of rate design, there is no cost basis for a change in the current rate structure.

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Rate Impact Analysis

As part of its application for changes to the system extension policies, as filed in the 2015 System Extension Application, FEI included a Rate Impact Analysis (RIA) to assist in determining whether new customers added to the system were paying their fair share of the cost of extending service. The use of the RIA was approved by the Commission in Order G-147-16.

The RIA looked at the total cost to the utility divided by the total system use in GJ with and without the inclusion of 7 years' worth of customer additions. The analysis included all of the capital costs associated with connecting new customers to the system, including meters & regulators, services and mains. Because customers are often required to make a Contribution in Aid of Construction (CIAC), those costs are born by the new customer and are not included in the RIA. Rather than using the full capital cost added to rate base associated with the new connections, the amount that would be included in the revenue requirements was developed. This reflects the costs that are used in developing rates for delivery service. This meant applying the return, depreciation and taxes applicable to the capital additions, forming the starting point for the incremental costs of adding new customers.

In addition, growth in O&M expenses was included to reflect the additional O&M costs related to customer growth. This was set at 50 percent times the growth rate in the number of customers, consistent with the PBR regulations. Finally, incremental costs associated with growth and sustainment were added based on 50 percent times the growth rate in the number of customers. This addition was based on direction from the Commission in Order G-147-16.

The incremental sales associated with 7 years' worth of customer additions was also determined. The added GJ was based on the actual customer additions multiplied by the weighted average use per customer for those added customers.

The results from the RIA are provided in the table below. To determine the incremental or marginal cost of delivery service, the total incremental costs associated with the 7 years of customer additions ($38.6 million) was divided by the total incremental sales (11.45 million GJ) associated with the 7 years of growth. The result is $3.~~7~~37 per GJ, as shown in line r of the table. This is 19% below the total system average delivery cost of $4.16 per GJ.

The RIA was developed to demonstrate that customer additions were not leading to higher rates for existing customers. In fact, the analysis showed that existing customers faced lower rates as a result of customer growth. This finding is consistent with marginal costs that are lower than embedded costs. More detailed discussion of the RIA can be found in the Application and resulting Decision.

It is important to note that the RIA was done for the system as a whole and not for individual customer groups. Looking at separate groups was not possible as mains were built for a mix of customers and could not be separated by customer group. The average system cost of $4.16 per GJ and the marginal cost of $3.3~~7~~7 per GJ are therefore for the system as a whole and may be more or less than the costs by customer group. It is important to point out, however, that while the incremental cost may be more or less than the average, the embedded cost by customer group would also be more or less than the average. We would expect the relative difference between the embedded cost and incremental cost to be similar between various rate groups.

Using the RIA is a good representation of the marginal cost over a medium time frame in the case when growth is a result of customer additions. It is not reflective of the marginal cost per GJ for added sales from existing customers when new meters, services and mains are not required.

Table 1
Rate Impacts Associated with Line & Mains Extension

(grey)	Actual data
(blue)	Formula driven results based on actual data and general assumptions

			2015 With Growth	2015 Without Growth	2008-2014 Growth Amount
This section uses existing actual delivery costs and looks at the impact on revenue requirements without the addition of capital for the new customers added in the past 7 years. (2008 to 2014).	A	2008-14 Meters/Regulators			$16,026,762
	B	2008-14 Services (Company Paid)			$119,082,263
	C	2008-14 Mains (Company Paid)			$58,435,929
	D	2008-2014 SJ and Internal Costs			$7,228,180
		50% Growth Sustainment			$2,775,000
	E	Rate Base	$3,656,399,000	$3,452,850,867	$203,548,133
	F	Return, Depreciation, Taxes	$522,883,000	$494,745,441	$28,137,559
	G	Multiplier for Return, Depreciation, Taxes	13.8%	13.8%	13.8%
	H	O&M Expenses	$238,093,000	$227,622,688	$10,470,312
	I	50% of Customer Growth Rate			4.4%
	J	Other Revenues/Expenses	-$3,942,000	-$3,942,000	$0
	K	Offsetting Bypass Revenues	-$29,802,000	-$29,802,000	$0
	L	Total Revenue Requirement (exc. Cost of Gas)	$757,034,000	$718,426,129	$38,607,871
	M	Net Revenue Requirement (exc. Cost of Gas)	$727,232,000	$688,624,129	$38,607,871
This section determines the usage associated with and without customers added to the system in the past 7 years.	N	Customers	970,399	885,051	85,348
	O	Percent Growth in Customers			8.8%
	p	Average GJ/Cust	180	184	134
	q	Total GJ	174,623,400	163,169,382	11,454,018
This section calculates the rate impact without the new customers added from 2008 to 2014.	r	Cost per GJ (exc. Cost of Gas)	$4.16	$4.22	$3.3~~7~~7

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Summary and Conclusions

The marginal cost of gas is something that can be considered when designing rate structures for FEI. Because the cost of gas supply is differentiated from delivery rates, we have looked at the marginal cost for delivery of gas only for use in examining the delivery rate structure. Two methods were developed to determine the marginal cost of gas for FEI. The first approach relies on the Rate Impact Analysis (RIA) used for FEI's 2015 System Extension Application. The second approach relies on the results of the 2012 LTRP.

The RIA shows a marginal cost of $3.~~7~~37 per GJ, which is 19% below the average system cost for the 2015 revenue requirement. This estimate is appropriate only in the case where sales are based on the addition of new customers and reflects a medium time frame. For the long-run cost associated with growth from new customers, the total system levelized cost of $0.20 would need to be added to this number. The result is still below the average embedded cost of delivery service.

The LTRP shows a long-run marginal cost of $0.20 for the system overall and is based on a 20-year planning horizon. This amount is appropriate for growth in GJ from existing customers.

In both cases the marginal cost is well below the average embedded cost of gas delivery. This would tend to imply that costs for all customers will be lower as a result of growth in sales and/or customers on the system.