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June 9, 2017

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

Project No. 3698899

2016 Rate Design Application (the Application)

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1

On December 19, 2016, FEI filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-30-17 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1. Reference: Exhibit B-1, page 1-3 and Appendix A2 page 6 and 6

- Principle 1: Recovering the Cost of Service; the aggregate of all customer rates and revenues must be sufficient to recover the utility's total cost of service
- Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates)
- Principle 3: Price signals that encourage efficient use and discourage inefficient use
- Principle 4: Customer understanding and acceptance
- Principle 5: Practical and cost-effective to implement (sustainable and meet long-term objectives).
- Principle 6: Rate stability (customer rate impact should be managed)
- Principle 7: Revenue stability
- Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained)

FEI does not apply the eight principles above in any priority or with any particular weighting. Rate design is a complex balancing process as it frequently requires the application of multiple, and sometimes conflicting, principles and the consideration of viewpoints from various stakeholders. In addition, different rate design principles may have varying levels of importance in different contexts. FEI, therefore, applies its experience and judgment to consider and balance the most relevant principles in a given context when identifying rate design issues and proposing rate design solutions. Rate design should strive to strike a balance among competing rate design principles based on specific characteristics of customers in each rate schedule.

Revenue-related Attributes:

1. *Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality or safety.*

2. *Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.*

3. *Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers, and with a sense of historical continuity.*

Cost-related Attributes:

4. *Static efficiency of the rate classes and rate blocks in discouraging wasteful use of the service, while promoting all justified types and amounts of use:*

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. *Reflections of all of the present and future private and social costs and benefits occasioned by the service's provision (i.e., all internalities and externalities).*

6. *Fairness of the specific rates in the apportionment of total cost of service among the different ratepayers, so as to avoid arbitrariness and capriciousness, and to attain equity in three dimensions: (1) horizontal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).*

7. *Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).*

8. *Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.*

Practical-related Attributes

9. *The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.*

1.1 Please confirm that the Principles adopted by FEI are intended to reflect the same principles articulated by Bonbright as laid out in the Elenchus COSA Report.

Response:

Confirmed. Please refer to page 9 (lines 2 and 3) of the Elenchus COSA report that confirms that the eight rate design principles adopted by FEI cover the same areas as the Bonbright Principles listed in Section 3 of Elenchus COSA report.

1.2 Please confirm that Principle 1, Principle 2, Principle 3, Principle 4, Principle 5, Principle 7 and Principle 8 of FEI's Principles would all be supported by a rate design at unity in revenue to cost ratios for each rate class.

Response:

Not confirmed, although Principles 2 and 8 are supported by achieving revenue to cost ratios within the range of reasonableness. Achieving unity implies a level of precision that does not exist with any COSA.

1.2.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC-FEI IR 1.1.2.

1.3 Please provide any thresholds or rates of change that FEI deems critical in managing Principle 6 - Rate Stability.

Response:

FEI does not consider any specific threshold or rate of change as critical in managing Principle 6 – Rate Stability.

FEI endeavors to limit customers' annual bill impact to 10 percent while balancing other rate design principles. At the same time, FEI is cognizant that there may be times when it is necessary to flow through rate changes that exceed 10 percent in order for the utility to recover its cost of gas and/or delivery cost of service.

1.4 Please confirm that FEI's Principle 7, Customer Understanding and Acceptance, relates to Bonbright Principle 9.

Response:

The rate design principle of Customer Understanding and Acceptance is FEI's Principle 4. FEI confirms that this principle relates to Bonbright Principle 9.

2. Reference: Exhibit B-1, page 1-5

Table 1-1: R:C and M:C Results before and after Rate Design Proposals and Rebalancing

Rate Schedule	COSA		Revenue Shifts and Rebalance Amount ($000)	Approximate Annual Bill Change	COSA after all Proposals and Rebalancing	
	R:C	M:C			R:C	M:C
Rate Schedule 1 *Residential Service*	95.6%	93.1%	848.1	0.1%	96.4%	94.4%
Rate Schedule 2 *Small Commercial Service*	101.3%	102.5%	(1,174.1)	-0.5%	102.2%	104.1%
Rate Schedule 3/23 *Large Commercial Sales and Transportation Service*	101.6%	103.3%	1,174.1	0.6%	103.6%	107.6%
Rate Schedule 5/25 *General Firm Sales and Transportation Service*	104.9%	112.2%	45.2	0.0%	106.3%	116.0%
Rate Schedule 6/6P *Natural Gas Vehicle Service*	131.2%	159.1%	(61.7)	-16.5%	110.0%	119.0%
Rate Schedule 22A *Transportation Service (Closed) Inland Service Area*	109.5%	109.8%			113.0%	113.4%
Rate Schedule 22B *Transportation Service (Closed) Columbia Service Area*	99.7%	99.7%			103.1%	103.1%
Rate Schedule 22 *Large Volume Transportation Service*	1425.5%	1864.4%	(754.2)	-3.4%	100.0%	100.0%

Rate Schedule *(rates not set using allocated costs)*	COSA		Revenue Shifts and Rebalance Amount ($000)	Approximate Annual Bill Change	COSA after all Proposals and Rebalancing	
	R:C	M:C			R:C	M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	147.4%	550.9%	13.3	1.9%	150.2%	578.3%
Rate Schedule 7/27 *General Interruptible Sales and Transportation Service*	139.6%	712.3%	(90.7)	-0.3%	139.3%	713.6%

2.1 Please confirm that Revenue/Cost ratio is a key indicator of fair apportionment of costs.

Response:

Not confirmed. As described in Section 6.2.1 of the Application, the first three steps of the cost allocation process lead to the fair apportionment of costs. The final step of the COSA study is to derive Revenue to Cost Ratios, which indicates whether the rates charged for each rate

schedule adequately recover the allocated cost of service (the fair apportionment of costs) based on the results of the COSA model.

2.2 Please confirm that FEI has used good load and costing data in its COSA evaluation.

Response:

FEI has used the most recent available data for its load forecast and approved costs at the time the COSA Study was prepared. FEI utilized 2016 approved load forecast and costs from its Annual Review for 2016 Delivery Rates proceeding for allocation within the COSA model. FEI chose these approved amounts as the base for allocation because they reflect current operating conditions, and they reflect the amalgamation of the gas utilities.

While FEI has used recent data to perform cost allocations, the accuracy of the results is a function of the number of assumptions embedded in the COSA Study. Because of the assumptions, generalizations, and extrapolation performed to produce final COSA results, it is impossible to know for certain the costs that any group of customers cause. A range of reasonableness around the resulting revenue to cost ratios must therefore be considered when contemplating any revenue shift and rate design proposals.

2.3 Please confirm that a Revenue/Cost ratio of 100% or 1 is the fairer apportionment of costs among customers.

Response:

Not confirmed. Please refer to Section 6.5.1 of the Application.

2.4 Please confirm that moving Revenue/Cost ratios towards 100% or 1 is directionally not unfair.

Response:

Revenue to cost ratios that fall within the range of reasonableness indicate that the rates of the customer classes recover the allocated cost of service. If revenue to cost ratios fall within the range of reasonableness, there is no compelling evidence to indicate that movement in any direction is required from the perspective of FEI's rate design Principle 2.

2.5 Please confirm that FEI's proposal results in Rate Schedule 2, Rate Schedule 3, Rate Schedule 5 Rate Schedule 22A, and Rate Schedule 22B and Rate Schedule 4 and Rate Schedule 7 all becoming increasing less fair based on the proposed Rate Design and Rebalancing.

Response:

Not confirmed. Even if there have been small increases in the R:C ratios for these classes, they all remain within the range of reasonableness.

2.5.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC-FEI IR 1.2.5.

3. Reference: BC Utilities Commission Act, Section 58.1

Rate rebalancing

58.1 (1) In this section, **"revenue-cost ratio"** means the amount determined by dividing the authority's revenues from a class of customers during a period of time by the authority's costs to serve that class of customers during the same period of time.

(2) This section applies despite:

(a) any other provision of

(i) this Act, or

(ii) the regulations, except a regulation under section 3, or

(b) any previous decision of the commission.

(3) The following decision and orders of the commission are of no force or effect to the extent that they require the authority to do anything for the purpose of changing revenue-cost ratios:

(a) 2007 RDA Phase 1 Decision, issued October 26, 2007;

(b) order G-111-07, issued September 7, 2007;

(c) order G-130-07, issued October 26, 2007;

(d) order G-10-08, issued January 21, 2008,

and the rates of the authority that applied immediately before this section comes into force continue to apply and are deemed to be just, reasonable and not unduly discriminatory.

(4) [Repealed RS1996-473-58.1 (5).]

(5) Subsection (4) is repealed on March 31, 2010.

(6) Nothing in subsection (3) prevents the commission from setting rates for the authority, but the commission, after March 31, 2010, may not set rates for the authority such that the revenue-cost ratio, expressed as a percentage, for any class of customers increases by more than 2 percentage points per year compared to the revenue-cost ratio for that class immediately before the increase.

3.1 Please confirm that Section 58.1 of the Utilities Commission Act applies expressly to the BC Hydro and Power Authority, and does not apply to FEI.

Response:

Confirmed.

3.2 Are there any legal or other requirements preventing FEI from rebalancing toward achieving unity? Please explain.

Response:

Rebalancing towards achieving unity would require a sufficient evidentiary foundation regarding what unity precisely is for each rate schedule. For the reasons discussed in Section 6.5.1 of the Application, FEI's COSA results are not accurate enough to provide a sufficient evidentiary basis to support Commission approval of rebalancing towards unity. Indeed, achieving unity implies a level of precision that does not exist with any COSA. Further, there are various factors to consider and balance when setting rates and therefore it may not be appropriate in many circumstances to rebalance toward achieving unity even if the results of the COSA were precise.

4. Reference: Exhibit B-1, page 1-6

> FEI is proposing the continuation of the flat rate structure for RS 1. The existing flat rate structure provides the best balance of rate design considerations for residential customers. Flat rates are simple to administer and easy to understand and provide more stable utility revenues and customer rates. The customer research survey results show that the flat rate structure is preferred by a majority of residential customers and the flat rate structure is used by the majority of Canadian natural gas utilities for their residential customers.

4.1 Please explain why a flat rate structure provides more stable utility revenues.

Response:

EES Consulting provides the following response.

With a flat rate structure, revenues will vary proportionately with changes in consumption due to weather, customer behavior or conservation efforts. With a declining or inverted block rate structure, the impact of load variances in one of the blocks is higher than the other. This has the potential to lead to a greater variation in revenue as a result of changes in consumption. With a declining block rate, there would be less variation for customers that have use within the second block, but more variation for customers with use falling within the first block. Conversely, with an inverted block rate there would be more variation for customers that have use within the second block, but less variation for customers with use falling within the first block. In either case, block rates make revenue less predictable and less stable.

4.2 Please confirm that a flat rate schedule does not provide a price signal to discourage wasteful use of energy, particularly under low or declining commodity price conditions.

Response:

EES Consulting provides the following response.

Because the proposed continuation of the flat rate structure for RS 1 is related only to the delivery cost of service, it is not intended to send price signals related to the cost of gas, assuming that is what was meant by the term commodity price. As indicated in Table 7-2 of the Application, compared to other rate structures, a flat rate can be considered a neutral option as it does not discourage or encourage consumption of natural gas in any particular pattern. A flat rate schedule for the delivery rate sends a greater price signal to discourage wasteful use of energy when compared to declining block rates. It sends a lesser price signal when compared to inclining block rates.

Please refer also to CEC-FEI IR 1.4.4.

4.3 Please confirm that customer preference for a rate structure is not a Bonbright Principle, whereas Principle 4 of the Bonbright principles promotes the use of rate blocks in discouraging wasteful use both for total use and relative use to other energy sources.

Response:

Principle 4, as stated on page 1-3 of the Application, is customer understanding and acceptance. While the term customer preference is not listed specifically, it is a component of customer acceptance and therefore a consideration in Principle 4. Discouraging wasteful use is included within Principle 3: Price signals that encourage efficient use and discourage inefficient use.

4.4 Please confirm that a flat rate schedule does not provide a price signal promoting the use of clean alternative energy.

Response:

As indicated in Table 7-2 of the Application, compared to other rate structures, a flat rate can be considered a neutral option as it does not discourage or encourage consumption of natural gas in any particular pattern. FEI's natural gas bills already include a carbon tax which is applied to customers' consumption and provides a clear price signal for the use of non-fossil fuel energy alternatives. The carbon tax is expected to increase in coming years, which would provide increased price signals for energy conservation. It should also be noted that there can be varying levels of price signals within a flat rate structure, depending on the balance of revenue recovery through fixed and volumetric charges.

5. Reference: Exhibit B-1, pages 3-17 to 3-20 and page 6-32 and Exhibit A2-2, page 6

Table 3-4: Past Commission Directives and FEI Commitments

FEI Application/Proceeding	Applicable Directive(s)/Reference & FEI Response

3.5 SUMMARY

In this section, FEI has provided an overview of FEI, its sales and transportation business models, customer rate schedule segmentation and regulatory history. This information has been provided as historical background to provide context regarding FEI's existing rate design and proposed changes in the following sections of the Application.

- In Commission Order G-130-07 in response to BC Hydro's 2007 Rate Design Application, the Commission determined that a "range of reasonableness of 95 per cent to 105 per cent [was] the correct range for the purpose of future rebalancing in the circumstances of BC Hydro."[89] The rationale for the decision was based in part on the "the known system demand and demand metering of large commercial and industrial customers" and "the accuracy of the relatively sophisticated load research analysis."[90] As a result, the Commission panel determined for BC Hydro "that the appropriate target R:C ratio in each class is unity or one and that future rebalancing should only be required when a customer class falls outside of the range of reasonableness."[91]
- Similarly, in Order G-156-10, dated October 19, 2010, the Commission found that "the appropriate range of reasonableness of 95% to 105% is the correct range for the purpose of future rebalancing in the circumstances of FortisBC [electric]."[92] As in the BC Hydro decision, the Commission determined that the appropriate target R:C in each rate

5.1 Please provide any commentary, direction, orders, regulations or other legislative content that FEI is aware of from the Commission that indicates that 100% (or a ratio of 1) is the appropriate target for cost of service ratios.

Response:

FEI is not aware of any commentary, direction, orders, regulations or other legislative content from the Commission that indicates that 100 percent (or a ratio of 1) is the appropriate target for cost of service ratios. However, please refer to the response to CEC-FEI IR 1.5.2 which includes excerpts from the decisions for electric utilities referenced in the preamble in which the Commission found that when rebalancing rates found to be outside the range of reasonableness the appropriate target for revenue-to-cost ratios was unity or one.

The Commission's Decisions with respect to natural gas utilities all indicate that R:C ratios within the range of reasonableness of 90 percent to 110 percent are acceptable. These decisions are reviewed in response to BCUC-FEI IR 1.14.1.

5.2 Please provide any commentary, direction, orders, regulations or other legislative content that FEI is aware of that relates to range of reasonableness for FEI or for BC Hydro.

Response:

As described in pages 6-32 to 6-34 the Application, recent Commission decisions suggest that a range of reasonableness of 95 per cent to 105 per cent is appropriate for electric utilities in British Columbia. Commission decisions for natural gas utilities, which have relatively less certain system demand data, support a wider range of reasonableness and there has been a long standing precedent to use a range of 90 per cent to 110 per cent.

Commission commentary and orders related to the range of reasonableness for electric utilities are provided below. Commentary and orders regarding natural gas utilities are provided in the response to BCUC-FEI IR 1.14.1.

BC Hydro

The range of reasonableness for BC Hydro was addressed in its 2007 Rate Design Application Phase 1, Order G-130-07, dated October 26, 2007, in which the Commission found at page 71 of the decision:

> The Commission Panel notes the wide spread practice of setting the range of reasonableness at 95 percent - 105 percent in other jurisdictions. Furthermore, the Commission Panel is persuaded by the JIESC position that once the key allocation methodologies have been properly established, the variation in cost of service and R/C results would be expected to be less than five percent and notes the evidence that there has been no systematic bias in allocation. The Commission Panel also agrees that in conjunction with the known system demand and demand metering of large commercial and industrial customers, the accuracy of the relatively sophisticated load research analysis should be acceptable within the overall range of reasonableness of 95 percent - 105 percent.
>
> Accordingly, the Commission Panel finds that the range of reasonableness of 95 percent – 105 percent is the correct range for the purpose of future rebalancing in the circumstances of BC Hydro. BC Hydro's proposed range of reasonableness of 90 percent to 110 percent is denied.

> The Commission Panel is further persuaded by the Intervenors' argument that under BC Hydro's approach of not making adjustments within its 90 percent - 110 percent band, those classes that start high will remain high and vice versa. Accordingly, the Commission Panel finds that the appropriate target for R/C ratios in each class is unity or one in this RDA, and that future rebalancing should only be required when a customer class falls outside of the range of reasonableness.
>
> BC Hydro is directed to adjust its rates in equal percentage amounts over the next three years so as to achieve R/C ratios of unity for each class after adjustments to the FACOS as described elsewhere in this Section and to file Rate Schedules for all classes for the first phase of the three year phase-in with rates effective April 1, 2008 with the Commission, together with supporting documentation, within 60 days of the date of Order No. G-111-07.
>
> BC Hydro is directed to undertake FACOS studies on an annual basis within 90 days of its fiscal year end in order to calculate actual R/C ratios and determine the need for future rate rebalancing applications in regard to the 95 percent to 105 percent range of reasonableness and submit the findings to the Commission.

In BC Hydro's 1991 Rate Design Application BC Hydro proposed and the Commission accepted a range of reasonableness of 85 percent to 115 percent. In the decision for Order G-36-92, dated April 24, 1992 in which the Commission found at page 71:

> The Commission accepts that the revenue to cost ratios resulting from the FACOS study do not indicate that a reallocation of class revenues is imperative at this time. In making this determination, the Commission is influenced by the evidence given by Mr. Vander Veen that the data upon which the study relies is of insufficient quality to allow for narrower bounds to surround the revenue cost ratios such as the 10 percent bounds which the Commission has accepted in the past.
>
> The Commission directs the Utility to undertake such measures as are necessary to improve the quality of its data so that a more reliable FACOS study may be prepared. Depending on the results of this study, a new allocation of revenues and costs among customer classes may be warranted. This undertaking may proceed without any special urgency since initial findings do not indicate a pressing problem. However, completion prior to a Revenue Requirement filing for 1993/94 would be most useful.

FortisBC Inc.

A proposed range of reasonableness of 95 per cent to 105 per cent for FortisBC Inc. (Electric) was also approved by the Commission in the 2009 Rate Design and Cost of Service Analysis Decision, Order G-156-10, dated October 19, 2010 at pp. 77-79:

> The Commission Panel notes BCMEU and BCOAPO's comments concerning the relative accuracy of FortisBC's load data as compared to BC Hydro's but also notes that neither party presented empirical evidence justifying their position that the range of reasonableness should be increased to 90 to 110 percent. The Commission Panel accepts FortisBC's assessment that there is no indication of systematic bias in the COSA. The Commission Panel also accepts FortisBC's position that the range of reasonableness is based not only on the accuracy of its data, but also on policy considerations such as the Commission's prior decision regarding the range of reasonableness for BC Hydro.
>
> In addition the Commission Panel considers that the load profiles of FortisBC and BC Hydro's Southern Interior delivery area are sufficiently comparable to give a degree of confidence in FortisBC's use of the latter's load research data.
>
> Accordingly, the Commission Panel finds that the range of reasonableness of 95 percent to 105 percent is the correct range for the purpose of future rebalancing in the circumstances of FortisBC. FortisBC's proposed range of reasonableness of 95 percent to 105 percent is approved.
>
> The Commission Panel recognizes that FortisBC's rate rebalancing approach that limits rate changes due to rebalancing to five percent per year is a compromise intended to accommodate the opposing positions of those customers whose R/C ratios are above the range of reasonableness, and those whose ratios are below it.
>
> The Commission Panel is further persuaded by Big White's argument that targeting unity in the rate rebalancing, rather than the end points of the range of reasonableness, will result in a more equitable distribution of revenue to cost ratios amongst customer classes at the end of five years.
>
> Accordingly, the Commission Panel finds that the appropriate target for revenue-to-cost ratios in each class is unity or one, and that future rebalancing should only be required when a customer class falls outside of the range of reasonableness.
>
> The Commission Panel has considered the requests of Big White for the introduction of a deferral mechanism to manage the rebalancing process, and the reply of FortisBC in this regard. The Commission Panel agrees with FortisBC that

such a mechanism would indeed be problematic and would result in additional cost to all ratepayers which the Commission Panel does not consider warranted.

FortisBC is directed to adjust its rates with the goal of achieving revenue-to-cost ratios of one for each class. Rate increases due to rebalancing alone are capped at five percent annually, with a 10 percent cap on increases resulting from rebalancing and revenue requirement increases combined, exclusive of increases to BC Hydro rates flowed through to FortisBC customers. The 10 percent cap does not apply to increases due solely to revenue requirements. Rebalancing will be determined on the basis of the updated COSA.

6. Reference: Exhibit A2-2, Elenchus Report, page 7 and page 29

> Since the allocation of shared costs amongst various customer classes can't be done in a perfectly accurate way and parameters or allocators are used to split shared costs, in many jurisdictions, a range of revenue to cost ratio is accepted as reflecting the fair allocation of costs to customer classes instead of thriving to achieve a revenue to cost ratio of 1.00 for all customer classes. Elenchus conducted a jurisdictional review and found that many jurisdiction use ranges of 0.95 to 1.05, or 0.90 to 1.10 as acceptable revenue to cost ratios when establishing revenue responsibilities by customer classes. Section 6 below discusses further revenue to cost and margin to cost ratios.

> By reviewing cost of service studies conducted by other major Canadian gas utilities, Elenchus found that R:C ratio is the typical ratio used in the industry although the accepted range of reasonableness is different for each utility. For ATCO, the Alberta Energy and Utilities Board (now AUC) noted that revenue to costs ratios within a target range of 0.95 to 1.05 are generally considered to be appropriate. The Board also noted that rates that vary from the target range after a consideration of other rate design criteria may be approved in order to take into account non-cost issues[46].
>
> Based on Elenchus experience, revenue to cost ratios that are within a range of acceptable values are considered to indicate that the customer class is paying its fair share of costs and that there is no need to realign cost responsibility. The usual revenue to cost range of acceptable ratios that Elenchus has observed is between 0.90 and 1.10 or a narrower range of 0.95 to 1.05. A narrower range of 0.95 to 1.05 is usually used by regulators and utilities in instances when there is good load and costing data available to be used in a COSA study and the utility and regulator have had experience and history in using COSA studies in order to set rates.

6.1 Please provide the full dataset on the range of reasonableness for other gas utilities that FEI has available.

Response:

EES Consulting provides the following response.

The range of reasonableness was not included as part of the jurisdictional review conducted by EES Consulting in Appendix 6-1 of Exhibit B-1 and therefore the information is not available. This information was not collected because the appropriate range of reasonableness has been

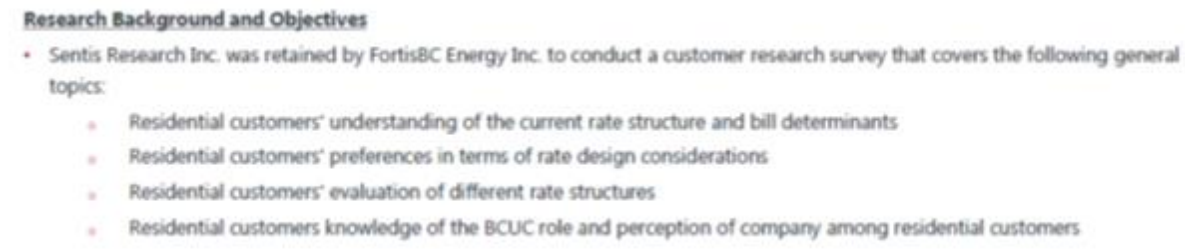
established by the Commission in past proceedings, and because the range of reasonableness generally reflects specific circumstances for the utility and jurisdiction. In EES' experience, the range typically is either 95 percent to 105 percent or 90 percent to 110 percent.

6.2 Please provide any other documentation that FEI has from consultants or other third parties that relate to the range of reasonableness for revenue to cost ratios for FEI or other gas providers.

Response:

Please refer to the response to CEC-FEI IR 1.6.1.

7. Reference: Exhibit B-1, Appendix 4-5, page 4



Research Background and Objectives

- Sentis Research Inc. was retained by FortisBC Energy Inc. to conduct a customer research survey that covers the following general topics:
  - Residential customers' understanding of the current rate structure and bill determinants
  - Residential customers' preferences in terms of rate design considerations
  - Residential customers' evaluation of different rate structures
  - Residential customers knowledge of the BCUC role and perception of company among residential customers

7.1 Please confirm that the Residential Customer Research Final Report is most appropriately applied to Rate Design within the rate class, and should not create any implications for cost of service related issues.

Response:

FEI confirms that the results of the residential customer survey are primarily used to inform FEI's rate design proposals within the residential rate class and not the cost allocation between rate schedules in the COSA model.

7.2 Please confirm that customer 'preference' is not the same as customer 'acceptance'.

Response:

Confirmed. Preference is defined as "a greater liking for one alternative over another or others" while acceptance is defined as "agreement with or belief in an idea, opinion, or explanation". Nevertheless, there is a positive relationship between preference and acceptance, meaning if you prefer one alternative over other existing alternatives, it is more likely that you will accept that alternative. In the residential customer research survey, the respondents were asked to rank various competing rate design considerations and not to accept any specific rate design proposal. The fact that the majority of FEI's residential customers preferred the existing flat structure over alternatives is good evidence that they accept that rate structure.

8. Reference: Exhibit B-1, Appendix 4-5, page 7

- The survey was conducted online using an online consumer panel. For Fort Nelson customers specifically, a telephone recruitment-to-online survey methodology (using a purchased list of Fort Nelson residential phone listings) was employed to obtain an oversample of Fort Nelson customers.
- To qualify for the survey, respondents must be individuals who are natural gas customers of FortisBC and who make payment decisions/review the natural gas bills.
- Sentis programmed and hosted the online survey at www.sentissurvey.com
- The survey was administered from July 25 to August 2, 2016. A total of 65 surveys were completed with Fort Nelson customers, and 753 surveys with customers from the rest of the province.
- The margin of error associated with each sample size is summarized below:

Region	Sample Size	Margins of Error (95% confidence level)
FEI	753	+/- 3.6%
Fort Nelson	65	+/- 12.2%

- Note: Throughout this report, "FEI" is used to refer to FortisBC Energy Inc. customers throughout the province excluding those from Fort Nelson. Fort Nelson customers will be referred to as such.

8.1 Were the participants in the group essentially self-selected or FEI selected, or was it a random sample?

Response:

Please refer to the responses to BCUC-FEI IRs 1.2.2, 1.2.2.1, 1.43.2 and 1.43.2.2.

8.1.1 If the group was self-selected or FEI selected, do the margins of error correct for any bias in the self-selection or FEI selection? Please explain and provide quantification of any bias to the extent it is available.

Response:

Please refer to the response to CEC-FEI IR 1.8.1.

9. Reference: Exhibit B-1, page 6-4 and page 6-18 and Appendix 6-6

- **Minimum System Study:** The MSS approach assumes that a certain level (percent) of distribution plant investment is required to serve the minimum loading requirements of customers throughout the service territory (i.e., those minimum costs are more dependent on the number of customers, rather than being variable based on demand). The closer a plant item is located to a customer, the more that particular item is related to the specific requirements of that customer. As such, costs associated with such plant investment should be regarded as customer related costs. The remaining percentage of costs is then attributed to the demand-related component since any costs associated with a system larger than the minimal plant investment are due to customers using a delivery quantity greater than the minimum unit up to the level of their peak demand. The result of the MSS determines the proportion of distribution mains costs that are customer related versus costs that are demand related.

  The MSS is only applicable to mains, as meters and services are classified as 100% customer-related. Costs associated with meters and services are fully allocated based on customer weighting factors as each customer needs a meter and service regardless of the volume of service taken by the customer.

  While the minimum system, in theory, is designed to meet the minimal loading requirements for all customers, the actual mains are capable of carrying a load beyond the minimal load. The proportion of costs allocated to the customer-related component is therefore overstated and requires an adjustment to account for the PLCC of the minimum system.

- **Peak Load Carrying Capacity Adjustment**: The PLCC adjustment involves determining the theoretical capacity of each of the distribution systems in the utility's total service area. To accomplish this, an average minimum system capacity per customer is calculated, which is then multiplied by the number of customers in each rate class, and the corresponding amount is subtracted from the demand for that rate class. The result accounts for the PLCC of the minimum system and effectively adjusts the proportion of costs allocated to the customer-related component to a more representative level.

6.3.5.4 Distribution

Costs for Distribution Mains have been split between demand and customer related components based on the minimum system approach with a PLCC adjustment. The minimum system approach with PLCC adjustment was used in the 2009 FortisBC Inc. (Electric) Rate Design Application[70] and also in FEI's 2012 Amalgamation Application.[71] It has been used for this rate design analysis on the recommendation of EES Consulting.[72]

Minimum System Study

FEI splits distribution rate base between demand and customer classifiers according to a minimum system approach. This approach considers that the distribution system is in place in part because there are customers connected to the system and in part because those customers have a peak demand on the system. Therefore, it follows that any costs associated with a system larger than this minimum size are due to the customer's demand, and so are treated as demand related. To support this approach, FEI has conducted an MSS.

1.

Appendix 6-6
SIZING OF DISTRIBUTION PIPE STANDARDS

9.1 Please provide all of FEI's standards for distribution lines, mains, pipe in relation to the number of customers that can be served from a given line or pipe size with the given appliance count estimate.

Response:

FEI's standard "Sizing of Distribution Pipe - Mains and Services" (CRL 1345), included in the Application as Appendix 6-6, is the only standard related to pipe sizing.

This standard does not relate a pipe size with a specific number of customers as customer loads can vary widely within rate schedules and more significantly across rate schedules. As well, the capacity of any particular pipe segment to support customer load is dependent on its location within a distribution network, expected minimum pressures at that location, and additional factors such as whether the pipe is supplied from one end or both. To account for these factors, the FEI standard requires that proposed pipe additions be assessed in consideration of the current hydraulic model of the distribution system, future expected growth and identified improvement plans and subsequently sized using a design formula.

9.2 Please confirm that the COSA utilizes actual costs and revenues.

Response:

Not confirmed. The COSA uses forecast costs and revenues from FEI's 2016 Annual Review plus adjustments for known and measurable changes as described in Section 6 of the Application.

9.3 In that FEI is currently operating under PBR, in which capital spending is exceeding the formula, please comment on whether or not there is any impact on the results of the COSA analysis.

Response:

In relation to the formulaic capital amount embedded in the test year which is used for the COSA model, there are no amounts included in rate base that exceed the formulaic capital amount, so there is no impact on the results of the COSA model.

10. Reference: Exhibit B-1, page 6-7 and Appendix 6-3 page

> ***6.3.1.2 Operating and Maintenance (O&M) Expenses***
>
> The COSA model requires an activity view of O&M expenses to assist with the cost allocation. In 2016, FEI is under performance based ratemaking (PBR) whereby total gross O&M is escalated using a formula.[61] The formulaic O&M in the approved revenue requirement is calculated based on total O&M and not at an activity level. To derive the necessary activity level of detail, FEI allocated the total approved O&M to each activity using the same percentages that existed in 2015 actual results. The ratio of each activity from 2015 to the total was applied to the 2016 approved formulaic O&M total so that the gross amount could be split into activities for allocation purposes within the COSA model. Appendix 6-3 shows the allocation percentages that were applied to FEI's 2016 formulaic O&M to derive an activity view for allocation in the COSA model.

FORTISBC ENERGY INC. Appendix 6-3

2016 Revenue Requirement O&M Split

		2016	Percentage
1	**Operating & Maintenance Expense**		
2	Distribution Supervision	$ 14,376.2	5.29%
3	Operation Centre - Distribution	11,848.4	4.36%
4	Preventative Maintenance - Distribution	2,664.7	0.98%
6	Operations - Distribution	7,104.0	2.62%
8	Emergency Management - Distribution	6,383.3	2.35%
10	Field Training - Distribution	2,825.5	1.04%
12	Meter Exchange - Distribution	3,032.3	1.12%
14	Corrective - Distribution	5,915.3	2.18%
16	Account Services - Distribution	1,432.1	0.53%
18	Bad Debt Management - Distribution	788.6	0.29%
20	**Distribution Total**	$ 56,370.5	
22			
24	Transmission Supervision	1,221.1	0.45%
26	Pipeline / Right of Way Operations	10,896.8	4.01%
28	Compression Operations	3,941.1	1.45%
30	Measurement Control Operations	861.8	0.32%
32	Pipeline / Right of Way - Maintenance	3,390.6	1.25%
34	Compression - Maintenance	2,719.0	1.00%
36	Measurement Control Operations	459.6	0.17%
38	Company Use Gas (Compression & Line Heating)	857.6	0.32%
40	**Transmission Total**	$ 24,347.5	

10.1 Please comment on why formulaic O&M is being used instead of Actuals.

Response:

FEI's historical practice has been to use a forecast test year when developing the COSA models supporting rate design. Consistent with past practice, FEI used formulaic O&M (which is the approved O&M) based on the forecast test year instead of actuals for the COSA Study in this Application.

10.2 When will 2016 Actuals be available?

Response:

2016 Actuals are currently available.

10.3 Please confirm that there are no significant variances that are likely to occur from year to year.

Response:

Confirmed that the percentages of the total O&M allocated to each function are expected to be relatively stable for the foreseeable future. As shown in the response to CEC-FEI IR 1.10.4, on a historical basis the insourcing of the customer service function in 2012 has continued to result in reduced costs, but is now expected to be stable, and there was an accounting change in 2014 that reduced the "Administration and General" costs. Other than these two items, there have not been any major fluctuations in other activity categories in the past five years.

10.3.1 If not confirmed, please provide an estimate of the range of variance that could occur in the allocation of O&M.

Response:

Please refer to the response to CEC-FEI IR 1.10.3.

10.4 Please provide 'Actuals' with percentages for the last 5 years including 2016.

Response:

The following table provides the requested information.

FORTISBC ENERGY INC
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
($000)

Line No.	Particulars	2016 Actual	Percentage	2015 Actual	Percentage	2014 Actual	Percentage	2013 Actual	Percentage	2012 Actual	Percentage
	(1)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Distribution Supervision	$ 14,098	5.4%	$ 13,764	5.3%	$ 13,517	5.2%	$ 11,898	4.5%	$ 11,716	4.6%
2	Support - Distribution	9,654	3.7%	11,343	4.4%	11,030	4.3%	10,145	3.8%	9,908	3.9%
3	Preventative Maintenance - Distribution	3,061	1.2%	2,551	1.0%	2,915	1.1%	2,593	1.0%	2,812	1.1%
4	Operations - Distribution	7,411	2.9%	6,801	2.6%	7,318	2.8%	7,613	2.9%	6,601	2.6%
5	Emergency Management - Distribution	5,902	2.3%	6,111	2.4%	6,490	2.5%	6,595	2.5%	6,554	2.6%
6	Field Training - Distribution	3,600	1.4%	2,705	1.0%	3,427	1.3%	3,546	1.3%	1,976	0.8%
7	Meter Exchange - Distribution	3,317	1.3%	2,903	1.1%	2,780	1.1%	2,708	1.0%	2,397	0.9%
8	Corrective - Distribution	5,401	2.1%	5,663	2.2%	5,536	2.1%	6,842	2.6%	6,223	2.4%
9	Account Services - Distribution	1,559	0.6%	1,371	0.5%	1,693	0.7%	1,292	0.5%	1,273	0.5%
10	Bad Debt Management - Distribution	899	0.3%	755	0.3%	1,090	0.4%	778	0.3%	698	0.3%
11	**Distribution Total**	**54,903**	**21.2%**	**53,964**	**20.8%**	**55,797**	**21.6%**	**54,010**	**20.4%**	**50,158**	**19.7%**
12											
13	Transmission Supervision	1,147	0.4%	1,169	0.4%	1,060	0.4%	934	0.4%	1,091	0.4%
14	Pipeline / Right of Way Operations	13,890	5.4%	12,403	4.8%	11,865	4.6%	10,486	4.0%	10,108	4.0%
15	Compression Operations	5,357	2.1%	5,009	1.9%	3,442	1.3%	2,975	1.1%	2,575	1.0%
16	Measurement Control Operations	1,187	0.5%	1,117	0.4%	325	0.1%	656	0.2%	580	0.2%
17	Pipeline / Right of Way - Maintenance	230	0.1%	1,275	0.5%	460	0.2%	837	0.3%	285	0.1%
18	Compression - Maintenance	1,043	0.4%	1,360	0.5%	717	0.3%	563	0.2%	440	0.2%
19	Measurement Control Maintenance	192	0.1%	148	0.1%	356	0.1%	280	0.1%	246	0.1%
20	Company Use Gas (Compression & Line	714	0.3%	827	0.3%	821	0.3%	798	0.3%	741	0.3%
21	**Transmission Total**	**23,760**	**9.2%**	**23,308**	**9.0%**	**19,046**	**7.4%**	**17,530**	**6.6%**	**16,066**	**6.3%**
22											
23	LNG Plant Operations	6,110	2.4%	4,967	1.9%	4,698	1.8%	4,331	1.6%	4,200	1.7%
24	LNG Plant Maintenance	910	0.4%	1,223	0.5%	683	0.3%	297	0.1%	175	0.1%
25	**LNG Plant Total**	**7,019**	**2.7%**	**6,190**	**2.4%**	**5,380**	**2.1%**	**4,629**	**1.7%**	**4,375**	**1.7%**
26											
27	Meter Reading	11,631	4.5%	11,274	4.3%	11,383	4.4%	12,453	4.7%	14,040	5.5%
28	**Meter Reading Total**	**11,631**	**4.5%**	**11,274**	**4.3%**	**11,383**	**4.4%**	**12,453**	**4.7%**	**14,040**	**5.5%**
29											
30	Energy Supply & Resource Development	2,355	0.9%	2,400	0.9%	2,511	1.0%	2,469	0.9%	1,982	0.8%
31	Gas Control	2,235	0.9%	2,113	0.8%	1,686	0.7%	1,562	0.6%	1,551	0.6%
32	**Energy Supply & Resource Development Total**	**4,590**	**1.8%**	**4,513**	**1.7%**	**4,196**	**1.6%**	**4,031**	**1.5%**	**3,533**	**1.4%**
33											
34	Facilities Management	9,836	3.8%	9,537	3.7%	9,719	3.8%	9,739	3.7%	11,006	4.3%
35	Supply Chain	4,470	1.7%	4,493	1.7%	4,822	1.9%	4,424	1.7%	4,420	1.7%
36	Measurement	7,028	2.7%	7,589	2.9%	7,012	2.7%	6,129	2.3%	5,764	2.3%
37	Property Services	1,699	0.7%	1,364	0.5%	1,625	0.6%	1,364	0.5%	1,216	0.5%
38	System Planning	7,035	2.7%	7,086	2.7%	6,837	2.7%	7,607	2.9%	5,760	2.3%
39	Engineering	8,733	3.4%	8,443	3.2%	7,613	3.0%	7,193	2.7%	7,023	2.8%
40	Project Management	614	0.2%	850	0.3%	933	0.4%	1,014	0.4%	1,125	0.4%
41	**General Operations Total**	**39,415**	**15.2%**	**39,363**	**15.1%**	**38,561**	**15.0%**	**37,469**	**14.1%**	**36,313**	**14.3%**
42											
43	Energy Solutions & External Relations Supervision	762	0.3%	971	0.4%	973	0.4%	1,014	0.4%	614	0.2%
44	Energy Solutions	8,204	3.2%	7,695	3.0%	6,480	2.5%	6,443	2.4%	6,272	2.5%
45	Energy Efficiency	1,479	0.6%	1,399	0.5%	889	0.3%	816	0.3%	659	0.3%
46	Corporate Communications & External Relations	8,155	3.1%	8,852	3.4%	7,411	2.9%	7,146	2.7%	7,475	2.9%
47	Resource Plan, Market & Business Development	6,589	2.5%	6,056	2.3%	6,181	2.4%	5,957	2.2%	4,998	2.0%
48	**Energy Solutions & External Relations Total**	**25,190**	**9.7%**	**24,974**	**9.6%**	**21,935**	**8.5%**	**21,376**	**8.1%**	**20,018**	**7.9%**
49											
50	Customer Service Supervision	291	0.1%	287	0.1%	814	0.3%	491	0.2%	482	0.2%
51	Customer Assistance	10,159	3.9%	10,493	4.0%	12,302	4.8%	12,089	4.6%	12,792	5.0%
52	Customer Billing	11,267	4.3%	11,668	4.5%	12,755	4.9%	25,267	9.5%	20,185	7.9%
53	Credit & Collections	1,815	0.7%	2,452	0.9%	4,997	1.9%	3,004	1.1%	3,567	1.4%
54	Customer Operations	3,319	1.3%	3,947	1.5%	3,242	1.3%	2,135	0.8%	2,543	1.0%
55	**Customer Service Total**	**26,850**	**10.3%**	**28,847**	**11.1%**	**34,110**	**13.2%**	**42,987**	**16.2%**	**39,569**	**15.6%**
56											
57	Information Systems Supervision	4,198	1.6%	4,830	1.9%	4,362	1.7%	4,185	1.6%	4,172	1.6%
58	Application Management	15,590	6.0%	14,594	5.6%	13,850	5.4%	13,728	5.2%	12,341	4.9%
59	Infrastructure Management	6,741	2.6%	8,805	3.4%	8,083	3.1%	7,418	2.8%	8,018	3.2%
60	**Information Systems Total**	**26,529**	**10.2%**	**28,229**	**10.9%**	**26,296**	**10.2%**	**25,331**	**9.6%**	**24,532**	**9.6%**
61											
62	Administration & General	(548)	-0.2%	(180)	-0.1%	187	0.1%	481	0.2%	189	0.1%
63	Shared Services Agreement	5,159	2.0%	4,481	1.7%	5,164	2.0%	4,525	1.7%	4,456	1.8%
64	Retiree Benefits	-	0.0%	(0)	0.0%	0	0.0%	6,709	2.5%	8,748	3.4%
65	Legal	2,056	0.8%	1,814	0.7%	2,174	0.8%	2,299	0.9%	2,044	0.8%
66	Internal Audit	799	0.3%	790	0.3%	792	0.3%	755	0.3%	695	0.3%
67	Risk Management/Insurance	5,888	2.3%	6,599	2.5%	6,491	2.5%	5,990	2.3%	5,795	2.3%
68	Environment Health & Safety	3,669	1.4%	3,159	1.2%	2,910	1.1%	2,680	1.0%	2,481	1.0%
69	Financial & Regulatory Services	13,534	5.2%	13,599	5.2%	14,080	5.5%	13,363	5.0%	12,609	5.0%
70	Human Resources	9,015	3.5%	9,109	3.5%	9,285	3.6%	8,305	3.1%	8,610	3.4%
71	**Administration & General Total**	**39,571**	**15.3%**	**39,372**	**15.1%**	**41,083**	**15.9%**	**45,107**	**17.0%**	**45,627**	**17.9%**
72											
73	**Total Gross O&M Expenses**	**259,459**	100.0%	**260,034**	100.0%	**257,788**	100.0%	**264,923**	100.0%	**254,232**	100.0%
74											
75	O&M Transferred to the BVA	(1,096)		(1,010)		(404)		-		-	
76	Capitalized Overhead	(32,594)		(32,457)		(32,605)		(38,233)		(36,958)	
77											
78	**Net Operating & Maintenance Expenses**	**$ 225,769**		**$ 226,568**		**$ 224,778**		**$ 226,690**		**$ 217,274**	

1

11. Reference: Exhibit B-1, page 6-10,

Table 6-5: Expected Project In-Service Dates and COSA Costs

Project	Expected In-Service Date	Mid-Year Rate Base included in COSA ($millions)	Cost of Service included in COSA ($millions)
Lower Mainland Intermediate Pressure System Upgrade Projects	October 2018	258	25
Coastal Transmission System Upgrade	November 2017	167	14
Tilbury Expansion Project	Mid 2017	399	7[68]

6.3.2.1 Lower Mainland Intermediate Pressure System Upgrade Project

The Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) CPCN application was filed with the Commission in December 2014 and approved through Order C-11-15. The LMIPSU includes the Coquitlam Gate IP Project which will address an increasing number of gas leaks on the Coquitlam Gate IP line. Operational flexibility and resiliency will be restored to the Metro Vancouver IP system and the Fraser Gate IP Project will provide required seismic upgrades to the Fraser Gate IP line. The Fraser Gate IP and the Coquitlam Gate IP Projects are expected to be in-service by October 2018. The estimated capital cost for the LMIPSU Projects, including AFUDC and abandonment/demolition costs, is approximately $256 million, with an initial annual cost of service of approximately $25 million. The LMIPSU Project's rate base and cost of service are included in the COSA model for allocation.

11.1 Please explain why the Mid Year Rate Base figures are slightly different than the figures cited in the write ups. For example, the LMIPSU Midyear Rate base is $258 million and the included cost is $256 million for the LMIPSU project description.

Response:

FEI incorrectly added (rather than subtracted) accumulated depreciation in the COSA model. The $256 million included in the write-up, which is referencing the LMIPSU capital cost, is correct. The corrected mid-year rate base is $253 million. Correcting the COSA model results in very minor cost allocation changes but does not result in any changes to FEI's rate proposals.

12. Reference: Exhibit B-1, page 6-14 and page 6-17

> The customer classes that are allocated costs of the Tilbury LNG Storage facility are Residential, Small and Large Commercial (both Sales and Transport), NGV (RS 6) and General Firm Service (Sales and Transport). Large Commercial and General Firm customers are included in the allocation because on peak days the Tilbury plant supports the supply and delivery to these sales and transport customers. General Interruptible (RS 7 and RS 27) and Large Industrial (RS 22) customers are not allocated Tilbury costs because on the days of extreme cold weather their service would be curtailed to preserve the capacity of the system to serve the firm load.
>
> ***6.3.5.2 LNG Storage***
>
> As discussed in Section 6.3.4.3, the existing Tilbury plant is a needle peaking facility designed predominantly to be used on extreme cold days. The Tilbury LNG Storage facility was included as a function in FEI's 1993, 1996 and 2001 Rate Design applications. The Tilbury function was

12.1 Does the Tilbury LNG storage never serve RS 7 or RS 27 or RS 22?

Response:

The primary purpose for Tilbury LNG is to serve as a needle peaking gas supply resource for firm core service customers. Beyond that, it is important to differentiate Tilbury LNG as a gas supply resource and Tilbury LNG as a system capacity resource, as send out from Tilbury can be called for either gas supply or operational capacity reasons.

As a gas supply resource the Tilbury LNG facility use is for the firm core market customers, i.e., Rate Schedules 1 to 6. The cost of the gas from the LNG facility is allocated only to these firm sales customers as part of the midstream resources.

From a gas supply resource and cost allocation perspective, Tilbury LNG storage does not serve General Interruptible (RS 7 and RS 27) or Large Industrial (RS 22) customers and is not sent out for these customers. However, it is possible to contend that RS 7, 27 and 22 implicitly receive an allocation of the Tilbury LNG cost of service because the rates for these rate schedules are set as a discount from firm service rate schedules that are explicitly allocated Tilbury costs.

From an operational capacity perspective, Tilbury LNG may be sent out for a variety of operational reasons, such as supporting transmission and distribution pipeline work, and as emergency backup supply to operational shortfalls. Many of these occurrences take place outside of the temperature curtailment threshold for these customers, and as such they may not be curtailed for capacity reasons at times when Tilbury LNG is sending out.

12.1.1 If the Tilbury LNG storage ever serves any of these Rate Schedules, please explain when and quantify the proportion of volume that is attributable to these rate schedules.

Response:

It is impossible to accurately quantify the LNG volumes that may incidentally be used in serving RS 7, RS 27 and RS 22 customers because there are many different variables involved and LNG makes up only a small amount of the overall gas supply portfolio on a given day. For example, on a given day the Shipper Agents that represent transportation customers could have brought on enough gas supply to cover their firm and interruptible customers' requirements; however, some sendout from Tilbury may have been needed to meet core gas supply requirements (that may have resulted from a sudden change in the weather).

Please refer to the response to CEC-FEI IR 1.12.1.

12.1.2 Please provide a record of Tilbury plant send out volumes by day, and a match of RS 7 or RS 27 or RS 22 consumption on those days, if there have been instances of Tilbury send out while RS 7, RS 27 or RS 22 customer have continued consumption.

Response:

No correlation or inferences can be drawn from the details of the table below as this is only a small snapshot of what happened on these days. The consumption volumes for RS 7, 27 and 22 customers are based upon consumption of the Lower Mainland customers in those rate classes only. As noted in the response to CEC-FEI IR 1.12.1, there are various reasons why interruptible volumes may be delivered on the same days that Tilbury send-out is occurring.

Tilbury LNG send out sample record for the past two years:

Date	Tilbury Sendout volume (mmscfd)	RS 7/27 Day consumption (mmscfd)	RS 22 Day consumption (mmscfd)	Comments
Nov 30, 2014	23.6	14.2	33.6	Cold weather sendout
Feb 24, 2015	6.9	14.5	33.4	Cold weather sendout

Date	Tilbury Sendout volume (mmscfd)	RS 7/27 Day consumption (mmscfd)	RS 22 Day consumption (mmscfd)	Comments
Feb 25, 2015	3.4	14.0	32.5	Cold weather sendout
Mar 25, 2015	4.9	12.8	41.1	Tilbury Vaporizer Test
Apr 05, 2016	3.9	22.7	38.8	Tilbury Send out Test
Apr 13, 2016	10.4	19.2	37.0	Tilbury Send out Test
Oct 20, 2016	4.9	13.9	30.4	Tilbury Send out Test
Oct 21, 2016	3.6	13.9	29.8	Tilbury Send out Test

1
2

13. Reference: Exhibit B-1, page 6-14

> As discussed in Section 6.3.2.3 of the Application, the Tilbury Expansion project is included in the LNG Storage function. However, the allocation approach for Tilbury Expansion does not follow that of the existing storage plant. The Tilbury Expansion costs are directly allocated to RS 46 and offset with RS 46 revenues (within the function) and the net difference is allocated to all non-bypass customers.

13.1 Why is the net difference allocated to all non-bypass customers?

Response:

As the LNG market grows and RS 46 revenues become greater than Tilbury Expansion costs, all non-bypass customers will benefit from the revenue greater than costs, so it is fair to allocate these same customers the net difference in the revenues and costs within the COSA model. Allocation to all non-bypass customers is also the treatment prescribed by Direction No. 5 for both RS 46 revenues and Tilbury Expansion costs.

13.2 On what basis is the net difference allocated to the different rate classes of non-bypass customers?

Response:

The net difference is allocated to other rate schedules using peak day demand which is the same allocator used for all other Tilbury functionalized costs.

14. Reference: Exhibit B-1, page 6-22

> 1. Calculate the **Peak Day Demand** for each region and rate schedule as follows:
>
> a. Develop a regression model for each region and rate schedule using 10 months[76] of actual demand data (converted to Daily Demand, based on the number of days in the month) against average monthly temperatures to establish the model parameters to a linear equation.
>
> b. Enter the regional design day temperature[77] into the above estimated linear models to establish the peak day demand for each region and rate schedule.
>
> 2. Calculate the **Average Daily Consumption** for each region and rate schedule:
>
> c. RS 1/RS 2/RS 3/RS 23:
>
> [76] July and August are excluded.
> [77] Design day temperature is derived through an Extreme Value Analysis, which estimates the coldest temperature expected to occur with a return period of one in twenty years.

14.1 Why are July and August excluded from the Peak Day Demand calculations?

Response:

Temperature sensitive load is assumed to be minimal or none in the summer months (July and August) when demand is the lowest. By excluding these warmer months from the regression analysis, FEI is able to develop a more reasonable forecast for the winter peak.

14.2 Please provide the Extreme Value Analysis used to estimate coldest temperatures.

Response:

The reference to the Extreme Value Analysis method in footnote 77 is incorrect. Consistent with past practice, the design day temperature used for this Application (as shown page 2 of Appendix 6-7 of the Application) is the same that has been used for FEI's previous rate design applications, and is also used for midstream cost allocations in FEI's fourth quarter gas cost filings.

15. Reference: Exhibit B-1, page 6-24

> ***6.3.6.1 Customer Costs***
>
> Customer-related costs are allocated across rate schedules on the basis of both average customers, and average customers with a weighting factor applied. Approximately 40% of FEI's customer-related costs are allocated using average customers with a weighting factor applied, 5% are allocated using only average customers and 55% are allocated based on the results of the two previous allocations. Customer-related costs that are allocated using average customers include land, structures, mains, measuring and regulating equipment. Customer-related costs that are allocated using average weighted customers include service lines and meters, customer billing and customer contact services including supporting infrastructure and energy solutions. Weighting average customers, and not simply using average customers, recognizes that not all customers cost the same to connect to FEI's system or cost the same to

15.1 Please provide the rationale for using 'average customers' for allocating land, structures, mains, measuring and regulating equipment costs.

Response:

The use of average customers as an allocator reflects both past and standard practice for the identified categories of costs. Average customers accommodates the varying customer growth rates in the rate schedules and the migration of customers between rate schedules. To the extent these costs have a customer-related component, it is due to the fact that a customer exists on the system and therefore average customers is used as an allocator of the customer-related components of these costs. Any issues related to the size or specific costs related to customers would be captured in the demand-related portion of the classification.

15.2 Please provide the rationale for using' average weighted customers' for allocating service lines, meters, customer billing and customer contact services including supporting infrastructure and energy solution costs.

Response:

The use of average weighted customers reflects both past and standard practice for these costs. Each of the listed cost areas pertain to facilities or activities closely and directly linked to serving the customer. While each customer typically has one meter, the cost of that meter differs by the type of customer. For example, the cost of a meter for a large commercial customer differs from that of a residential customer due to the fact that the large commercial meter must measure demand as well as energy readings. Customer billing and contact services also differ by customer type based on the level of effort required to serve that

customer. Not all customer types require the same amount of time or effort. The weighted customer factor accounts for those differences.

15.3 Please define 'energy solutions".

Response:

Energy Solutions includes residential and commercial sales, commercial account management, industrial account management, customer connection and retention-related marketing, as well as DSM-related customer contact and program support.

15.5 Please explain how the remaining 55% of costs are 'allocated based on the results of the previous 2 allocations'.

Response:

While some items are classified and allocated directly using only one allocator, such as average customers or average weighted customers as discussed in Section 6.3.6.1, many other accounts are classified and allocated to follow the classification and allocation of a specific rate base account, the sum of various rate base accounts, or the sum of other revenue requirement expense accounts. This is typically done because the expenses are more general in nature and cannot be directly classified and allocated by any one factor.

Of the remaining 55 percent customer-related costs discussed in the question, 32 percent are allocated using total distribution rate base classified as customer. A specific example of an item that is in the 55 percent category is distribution earned return. A portion of FEI's earned return is functionalized as distribution and this amount is allocated across FEI's rate schedules using the total distribution rate base that has been classified as customer and allocated to those same rate schedules.

15.6 What are the remaining 55% of costs that are allocated based on both the previous allocations?

Response:

The remaining 55 percent of costs includes general items such as Distribution Supervision, Distribution Operations, Human Resource Services as well as the Rate Base Return, Depreciation and Taxes associated with General Plant.

15.7 Please provide the rationale for why the remaining costs are not able to be allocated based either on average customers, or average weighted customers.

Response:

Please refer to the response to CEC-FEI IR 1.15.5.

15.8 Please confirm that FEI uses the best possible information it has available to determine the weightings.

Response:

Confirmed.

16. Reference: Exhibit B-1, page 6-15

Table 6-15: Customer Weighting Factor Study and Customer Administration Factor Results

Rate Schedule	Customer Weighting Factor	Customer Admin & Billing Factor
1	1.0	1.0
2	1.7	1.0
3	7.0	1.2
4	13.6	0.9
5	11.1	43.0
6	13.3	43.0
7	132.5	43.0
22	49.9	75.0
22A	399.2	75.0
22B	562.6	75.0
23	10.3	75.0
25	17.6	75.0
27	46.2	75.0

Based on information from FEI's marketing, customer service and billing departments, weighting factors for each rate class were developed which take into consideration:

- the frequency of meter reading;
- the use of remote meter reading via cellular or other communications infrastructure and the method of collecting and retaining load data;
- the amount of time spent by customer service responding to inquiries;
- marketing programs and costs for different customer groups;
- the existence of dedicated account managers for commercial and industrial customers; and
- the number of resources dedicated to each customer class for customer billing, measurement and marketing.

The customer numbers in each rate schedule that are weighted for customer administration and billing are then used to allocate costs associated with customer administration to each rate schedule.

16.1 Did FEI rely on empirical evidence to support its weightings, or are the weightings more judgement based? Please explain.

Response:

FEI relied on discussions with internal staff about the approximate level of effort required to service different types of customers for the Customer Administration and Billing Factors, taking into consideration the factors listed on page 6-15 of the Application as quoted in the preamble. While this approximate level of effort was not based on the actual tracking of hours by customer class, it was based on internal knowledge from staff responsible for customer administration and billing.

16.1.1 If FEI has empirical evidence, please provide the empirical evidence behind these weighting factors.

Response:

Please refer to the response to CEC-FEI 1.16.1.

16.1.2 If FEI does not have empirical evidence to support all of its weightings, please identify in what instances FEI has relied on judgement to assign weights.

Response:

Please refer to the response to CEC-FEI IR 1.16.1.

16.2 Please provide FEI's historical weightings from previous cost of service studies.

Response:

The following table shows the FEI weightings used for the 2012 COSA provided in the Common Rates, Amalgamation and Rate Design Application. Prior to amalgamation the weightings would have been related to specific service areas, with different customer classes in some cases, and are not comparable to the FEI factors included in this Application. In addition to the

2012 Customer Weighting Factor also below are the weighting factors from the 2001 Rate Design, 1996 Rate Design and the 1993 Phase B Rate Design Application.

Table 1: Common Rates, Amalgamation and Rate Design Customer Weighting Factors (2012)

Rate Schedule	Customer Weighting Factor	Customer Admin & Billing Factor
1	1.0	1.0
2	1.7	1.0
3	6.8	1.2
4	13.2	0.8
5	11.8	43.0
6	14.2	43.0
7	37.2	43.0
22	38.6	75.0
23	10.0	75.0
25	16.5	75.0
27	31.7	75.0

Table 2: 2001 Rate Design Customer Weighting Factors

Rate Schedule	Customer Weighting Factor
1	1.00
2	1.18
3	2.80
4	10.31
5	6.91
6	7.13
7	21.57
22	32.26
22A & 22B	208.57
23	5.39
25	11.30
27	18.69

Table 3: 1996 Rate Design Customer Weighting Factors

Rate Schedule	Lower Mainland	Inland	Columbia
1	1.00	1.00	1.00
2	1.23	1.25	1.30
3	3.40	5.23	4.65

Rate Schedule	Lower Mainland	Inland	Columbia
4	6.22	25.08	N / A
5	6.99	14.76	11.38
6	4.98	7.69	3.43
7	23.35	67.36	N / A
22	37.58	N / A	N / A
22A / 22B	N / A	241.73	247.35
25	14.98	28.56	26.02
27	19.75	27.84	N / A

Table 4: 1993 Phase B Rate Design Customer Weighting Factors

Lower Mainland		Inland		Columbia	
Rate Schedule	Weighting	Rate Schedule	Weighting	Rate Schedule	Weighting
Residential	1.00	Residential	1.00	Residential	1.0
General Service	1.52	Commercial	1.62	General Service	1.6
Medium Industrial Sales & T-Service	5.84	Small Industrial Sales & T-Service	26.88	Small Industrial Sales & T-Service	28.8
NGV / VRA	2.39	NGV / VRA	2.74	NGV / VRA	2.9
Seasonal	6.07	Seasonal	39.75	Seasonal	28.8
Interruptible Large T-Service	37.21				
Large Industrial T-Service		Large Industrial Sales & T-Service	316.65	Firm Large Industrial T-Service	319.6

16.2.1 Please confirm that FEI uses the best possible information it has to determine these weightings.

Response:

Confirmed.

17. Reference: Exhibit B-1, page 6-26

> 6.3.6.1.2 WEIGHTING FACTOR FOR METERS AND SERVICES
>
> The facility costs for the distribution system, such as meters, service lines and regulators, are not equal among all customers. Therefore, for these costs, FEI applies a weighting factor to the number of customers in each rate schedule so that the costs allocated to each rate schedule are proportionate to the costs to serve them.
>
> The weighting factors are estimated values indicating the total relative value of meter and service assets associated with a specific rate schedule as compared to Rate Schedule 1.[83] Once the weighting factors have been calculated and assigned to each rate schedule, costs can be allocated appropriately across all rate schedules. This weighting factor helps ensure each rate schedule is assigned the appropriate proportion of customer-related costs based on cost causation.

17.1 Did FEI rely on judgement in providing weights or does it have empirical evidence to support its weightings?

Response:

FEI used empirical evidence to develop weighting factors for meters and services. The factors were developed using the costs of meters and services for each specific type of customer.

17.1.1 If FEI has empirical evidence, please provide the empirical evidence behind these weighting factors.

Response:

Please refer to the response to BCOAPO-FEI IR 1.6.6a.

17.1.2 If FEI does not have empirical evidence to support its weightings, please identify in what instances FEI has relied on judgement to assign weights.

Response:

Please refer to the response to CEC-FEI IR 1.17.1.

17.2 Please provide FEI's historical weightings from previous cost of service studies.

Response:

Please refer to the response to CEC-FEI IR 1.16.2.

18. Reference: Exhibit B-1, page 6-30

> ***6.4.2.1 Load Factor Adjustment to RS 5 Customers***
>
> As noted above, FEI currently allocates midstream costs to RS 5 using a deemed 50% load factor. This value was established as part of the 1996 Rate Design Application Negotiated Settlement Agreement. FEI contracts for its midstream resources based on a peak day demand that is derived using a calculated load factor for RS 5, not a deemed load factor. This discrepancy means that the cost of the resources being contracted for is not being allocated to RS 5 in the same way in which they were caused.
>
> Based upon the rate design principles to fairly apportion costs among customers and set price signals that encourage efficient use, FEI is proposing to utilize the same approach for allocating midstream costs to RS 5 as it does for RS 1, RS 2, and RS 3 by using a three-year rolling average load factor as discussed in Section 6.4.2. Under the new approach the load factor used to allocate midstream costs to RS 5 would be approximately 45%[86]. For clarity, 45% is the indicative load factor; however, the load factor that will be used to allocate midstream costs to RS 5 will be recalculated annually along with the load factors used to allocate midstream costs to RS 1, RS 2, and RS 3.
>
> Table 6-17 below shows that changing the deemed RS 5 load factor from 50% to 45% changes the allocation of midstream costs and midstream charges for sales customers. The table is based on the data used to set January 1, 2016 midstream rates.[87]

18.1 What was the previous rationale for using a deemed load factor of 50% instead of the rolling average approach FEI is now proposing?

Response:

The deemed 50 percent load factor for RS 5 was the result of a negotiated settlement process pertaining to FEI's (then BC Gas's) 1996 Rate Design Application. The 50 percent deemed load factor for gas cost allocations was one of a series of items approved for RS 5/25 by Order G-98-96. Since the 50 percent deemed load factor result was established by way of a negotiated settlement the rationale for adopting it is not a matter of public record.

18.2 Please provide the 3 year rolling average load factor for all rate classes for the last 10 years.

Response:

The requested information is provided in the table below.

	2005-2007	2006-2008	2007-2009	2008-2010	2009-2011	2010-2012	2011-2013	2012-2014	2013-2015
Rate 1	0.298	0.296	0.294	0.298	0.296	0.301	0.298	0.305	0.312
Rate 2	0.295	0.297	0.297	0.301	0.298	0.300	0.299	0.301	0.311
Rate 3	0.357	0.375	0.382	0.382	0.380	0.355	0.358	0.362	0.371
Rate 5	0.482	0.483	0.488	0.481	0.484	0.483	0.479	0.458	0.451
Rate 23	0.350	0.321	0.320	0.313	0.340	0.353	0.367	0.362	0.369
Rate 25	0.529	0.528	0.531	0.526	0.528	0.543	0.559	0.561	0.555

18.3 Please confirm that FEI is using the best information it has available to determine load factors for allocation of midstream costs.

Response:

Confirmed. This confirmation is subject to the recognition that FEI currently uses a deemed 50 percent load factor for allocation of midstream costs for RS 5. In the Application, FEI is proposing to utilize a three-year rolling average load factor for allocating midstream costs to RS 5 as is done for Rate Schedules 1, 2, and 3.

FEI uses the latest available three-year historical data in determination of the rolling average load factors. For example, the FEI 2016 Fourth Quarter Gas Cost Report, which provided the calculations for setting the midstream rates (Storage and Transport Charges, and the MCRA Rate Rider 6 amounts) effective January 1, 2017, used the rolling average load factors for Rate Schedules 1, 2, and 3 based on the historical 2013, 2014, and 2015 load factor data.

19. Reference: Exhibit B-1, page 6-32

> **6.5.1 R:C Ratios – The Range of Reasonableness**
>
> R:C ratios are assessed based on whether or not they fall within an established "range of reasonableness". FEI believes that the appropriate range of reasonableness for evaluating its R:C ratios is 90 per cent to 110 per cent. In theory, the R:C ratio should equal 100% for each rate schedule, indicating that the revenues recovered from each rate schedule would equal the indicated cost to serve them. However, achieving unity implies a level of precision that does not exist with any COSA. As a COSA study necessarily involves assumptions, estimates, simplifications, judgments and generalizations, a range of reasonableness is warranted and accepted when evaluating the appropriateness of the R:C ratios.

19.1 Please provide FEI's basis for the assumption that 10% is the appropriate range of reasonableness, as opposed to, for example, 5% or 7%.

Response:

Please refer to the response to BCUC-FEI IR 1.14.1.

19.2 Has FEI always relied on 10% as the appropriate range of reasonableness?

Response:

The range of reasonableness of 90 percent to 110 percent has been used consistently in past rate design proceedings such as the 1993 Phase B Rate Design, the 1996 Rate Design, the 2001 Rate Design, and the 2012 Common Rates, Amalgamation and Rate Design.

19.2.1 If not, what other figures has FEI relied on?

Response:

Please refer to the response to CEC-FEI IR 1.19.2.

19.3 Please discuss the historical stability of FEI's revenue to cost ratios for each rate class over the last 20 years, and provide quantification of FEI's revenue to cost ratios over this period.

Response:

The following table shows the revenue to cost ratios as well as the margin to cost ratios for the rate designs undertaken since 1993. The results of each study will be different in part based on the treatment of revenues and as new infrastructure costs are incurred. In the 2012 COSA study, the revenues of Bypass, RS 22A, RS 22B and the two Contract customers (BC Hydro IG and VIGJV) were treated as credits to all other rate schedules.

Particulars	Residential	Small Commercial	Large Commercial	Seasonal	General Firm	NGV / VRA	Interruptible Small Industrial	Large Industrial T-Service RS 22	Large Industrial T-Service RS 22A	Large Industrial T-Service RS 22B
1993 Post Phase B Decision M:C										
Coincident Peak	90%	95%	100%	127%	117%	82%	780%	754%	123%	90%
Non-Coincident Peak	96%	104%	113%	87%	124%	83%	140%	80%	85%	84%
Average & Excess	97%	107%	112%	79%	114%	79%	126%	76%	82%	81%
1996 Rate Design Application M:C										
Coincident Peak	87.1%	95.0%	117.0%	181.1%	186.1%	67.8%	875.4%	1827.8%	111.2%	115.5%
Non-Coincident Peak	90.8%	101.0%	127.6%	158.2%	203.7%	68.4%	171.4%	164.9%	89.4%	126.4%
Average & Excess	91.6%	103.1%	128.3%	137.5%	184.0%	66.9%	155.8%	144.9%	83.7%	121.7%
1996 Rate Design Settlement M:C										
Coincident Peak	91.4%	96.1%	103.9%		137.5%	67.3%			108.8%	111.3%
1996 Rate Design Settlement R:C										
Coincident Peak	95.3%	98.2%	101.6%			74.3%				
2001 Rate Design Application M:C										
Coincident Peak	92.0%	104.2%	118.2%	288.1%	123.3%	102.1%			93.4%	110.0%
2001 Rate Design Application R:C										
Coincident Peak	96.5%	101.5%	105.1%	119.8%	102.1%	101.0%				
2012 Common Rates, Amalgamation & Rate Design R:C [1)]										
Coincident Peak	93.4%	104.6%	107.9%		110.4%	112.7%				
2016 Rate Design Application M:C Initial COSA										
Coincident Peak	93.1%	102.5%	103.3%	550.9%	112.2%	159.1%	712.3%	1864.4%	109.8%	99.7%
2016 Rate Design Application R:C										
Coincident Peak	95.6%	101.3%	101.6%	147.4%	104.9%	131.2%	139.6%	1425.5%	109.5%	99.7%
2016 Rate Design Application M:C COSA after Rate Design Proposals										
Coincident Peak	94.4%	104.1%	107.6%	578.3%	116.0%	160.4%	713.6%	100.0%	113.4%	103.1%
2016 Rate Design Application R:C										
Coincident Peak	96.4%	102.2%	103.6%	150.2%	106.3%	131.7%	139.3%	100.0%	113.0%	103.1%

[1] 2012 Common Rates, Amalgamation and Rate Design Application, Page 220, Table 9-10.

As can be seen from the table, the residential margin to cost ratios from the 1993 and 1996 Rate Design applications were in the high 80s to low 90s percentage range (coincident peak method), and are now in the mid-90s percentage range. Small Commercial and Large Commercial M:C and R:C ratios are generally in the 96 percent to 107 percent range.

Caution needs to be exercised when trying to compare the results from one COSA study to another done at a different time. The COSA methodologies employed have been substantially the same, but the corporate configuration has changed, with only the two most recent COSAs (2012 and 2016) covering the current amalgamated utility.

19.4 Please confirm that despite the existence of a 'range of reasonableness' and the use of assumptions it remains appropriate for the utility to achieve unity in its cost of service ratios based on the data available.

Response:

Not confirmed. It is not appropriate for the utility to achieve unity in its cost of service ratios for each rate schedule based on the data available. Please refer to Section 6.5.1 of the Application and the response to BCUC-FEI IR 1.14.1.

19.4.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC-FEI IR 1.19.4.

19.5 Please confirm that where the data is not illustrative of unity in cost of service, it remains appropriate for the utility to achieve unity.

Response:

Not confirmed. Please refer to Section 6.5.1 of the Application and the response to BCUC-FEI IR 1.14.1.

19.6 Please confirm that the key issue with respect to rebalancing the revenue to cost ratios is the potential for rate impacts on customer classes with ratios below 1.

Response:

Not confirmed. The potential for rate impacts on customer classes with ratios below 1 is not the key issue with respect to rebalancing the revenue to cost ratios; rather, it is one rate design consideration among other considerations affecting rebalancing.

Rebalancing by shifting revenues between different rate schedules, and the resultant changes to the revenue to cost ratios, is one aspect of rebalancing. The reasons for rebalancing of this type, such as for RS 6, is to bring the revenues collected into closer alignment with the allocated cost to serve that rate schedule.

Meeting other rate design objectives for General Firm Service has resulted in rebalancing. Also, the rebalancing for the Commercial rate schedules was the result of achieving rate design objectives not related to revenue to cost ratios.

19.6.1 If not confirmed, please explain why not and outline the issues that would arise in rate rebalancing.

Response:

Please refer to the response to CEC-FEI IR 1.19.6.

19.7 What 'range of reasonableness' has FEI applied to rate impacts, if any?

Response:

FEI has not set a range of reasonableness with regard to rate impacts, but considers the potential for rate shock in any of its recommendations.

19.8 If revenue to cost ratios were rebalanced toward 1 or unity periodically, say very five or ten years, would FEI find such a Commission decision to be unfair, particularly if changes to rates were made within a range of reasonableness for rebalancing rate changes? Please explain why or why not.

Response:

Achieving unity implies a level of precision that does not exist with any COSA. Consistent with past determinations of the Commission, a revenue to cost ratio within the range of reasonableness indicates that a rate schedule is recovering its fair cost, and is not compelling evidence of a need to rebalance rates. Therefore, as long as the revenue to cost ratios remain within the range of reasonableness, there would be no need to rebalance rates periodically (to unity or otherwise).

FEI also notes that setting the rates for seasonal and interruptible customers served under Rate Schedules 4, 7, and 27 to achieve unity would be unfair to customers in other rate schedules in that it would allow these customers to be 'free riders' on FEI's transmission and distribution systems. Continuing to price these rate schedules on a value-of-service basis is another reason that other rate schedules do not have to have rates that result in unity.

20. Reference: Exhibit B-1, page 7-1

> FEI is also proposing a 5% increase in the Basic Charge and a corresponding decrease in the volumetric Delivery Charge, such that the change is revenue neutral within RS 1. This proposal achieves a reasonable balance among competing rate design considerations. A one-time 5% increase in the Basic Charge and a corresponding decrease in the volumetric Delivery Charge will improve the cost recovery from low-consumption customers. The change will result in only a small annual bill impact for the majority of customers (less than 1%), and zero bill impact for an average use customer.

20.1 Please describe the competing objectives in this rebalancing and what makes a one time 5% change the appropriate end-point.

Response:

FEI's reasoning for the proposed 5 percent revenue-neutral increase to Basic Charge and the review of corresponding rate design considerations for this proposal are described in detail in Sections 7.5, 7.6 and 7.8 of the Application. FEI provides the following summary discussion.

The main objective of FEI's proposal is to improve the balance among competing rate design considerations. On one hand, an increase in the share of fixed charges in the recovery of fixed costs will improve the intra-rate schedule fairness and will ameliorate possible imbalances in interests among residential customers, particularly between the low use and medium / high use groups. The proposal will also slightly improve revenue and rate stability, and is consistent with practices in other Canadian natural gas distribution utilities, as well as Commission's past decisions. On the other hand, government energy policies and bill impact analysis limit the desirability of making larger increases to the Basic Charge. The proposed 5 percent revenue-neutral increase does not lead to any significant bill impact for any individual residential customer and does not discourage customers' involvement in demand-side management programs since a significant portion of customers' monthly bills continues to be recovered through volumetric charges. As such FEI believes that 5 percent increase is reasonable and should be approved as proposed.

21. Reference: Exhibit B-1, page 7-7

> To date, the decrease in demand due to declining residential use per customer has been nearly offset by the increase in demand from the newly attached residential customers. Nevertheless, the future rate levels and rate structure should consider options than can fairly mitigate the potential for a decrease in overall residential demand due to declining residential UPC.

21.1 What options does FEI suggest should be considered to counter or fairly mitigate the prospect of overall reduction in customer demand based on declining use per customer.

Response:

As suggested in the preamble to this question, the impact of declining use per customer on total throughput and customer rates can be mitigated by actions and initiatives that support the attachment of new customers and encourage the existing customers to remain as natural gas customers. For instance, FEI's recent system extension application and decision (Order G-147-16, dated September 16, 2016) introduced new customer connection policies that will help potential customers to attach to FEI's system. Continuing the pursuit of growth opportunities in other sectors, such as natural gas for transportation in trucking, marine and mining, or remote power generation also presents possibilities for partial mitigation of lost revenues from declining residential use while serving other government policy objectives such as GHG emission reductions.

21.2 What are the beneficial consequences of declining use per customer what are the negative consequences? Please elaborate with quantification where possible.

Response:

The declining use per customer has no positive impact on FEI's rate design or rates. The declining use per customer, if not offset by the use from new customer additions, can lead to higher rates for all customers. As residential UPC declines, the reduction in revenue manifests as a revenue deficiency in FEI's revenue requirements. The deficiency is typically spread across all non-bypass rate schedules based on their existing margin as an increase in delivery rates. A one GJ decline in residential use per customer, assuming all other things held constant, is approximately a 0.7 percent delivery rate increase for all non-bypass customers.

On the positive side, declining use per customer is indicative of positive benefits from a societal perspective, such as improving energy efficiency amongst natural gas consumers and lower

1 greenhouse gas emissions. Declining use per customer may also reduce customers' total bills
2 for natural gas. As discussed above, the declining use rate will cause delivery rates to increase
3 but customers will pay less for the commodity portion of their bills.

4

22. Reference: Exhibit B-1, page 7-13

Table 7-2: Evaluation of Rate Structure Options Based on Major Rate Design Considerations

	Flat Rate	Declining Block Rate	Seasonal Rate	Inverted Block Rate
Ease of Understanding and Administration	It is easy to understand. The ease of understanding for the general public will lead to relatively higher customer satisfaction, less cost pressures and easier administration of the residential rate schedule.	The logic behind a declining block rate structure is not easily understandable to the general public and some may misinterpret it as a form of subsidization to high use customers or contrary to energy conservation and environmental objectives.	The concepts of peak demand and related costs attributed to seasonal rates may not be easily understandable to some customers. There is no simple methodology to come up with the ratio of winter to summer rates. This makes the administration of this rate more difficult. Administration related to customer bill inquiries will also be greater relative to simpler rate structures	Similar to declining rates, the inverted rates may not be easy to understand for some customers. Customers may not know at what level of consumption and at what time of a month their consumption goes over the first block, leading to higher customer dissatisfaction.
Economic Efficiency and Fairness	Compared to other rate structures, flat rate can be considered a neutral option for economic efficiency and fairness as it does not discourage or encourage consumption of natural gas in any particular pattern.	This rate structure could be efficient for those situations where higher load factor customers are also higher volume customers. From a cost perspective, declining rates can be justified when the long-run incremental cost of service is below the average cost, which is the case for FEI.	A seasonal rate is used as a proxy for a demand charge to ensure that the costs of serving peak winter demands are allocated to those most responsible for causing them. Seasonal rates will reduce the price competitiveness of natural gas during the winter when natural gas is most valued by customers. Seasonal rates can be said to introduce a form of regional price differential since the customers in colder environments might be impacted more than others.	Natural gas distribution is widely considered to have economies of scale, meaning that as the size of the utility increases (i.e., increased consumption), the total average cost of the utility decreases. Therefore, there is no cost basis to justify inverted block rates for natural gas utilities. Inverted rates may send inefficient price signals because low volume customers could be subsidized.
Customer bill impact	Flat rates help with customer bill impact since there will be no change in the volumetric rate based on consumption level.	Depending on the portion of costs recovered in the first block, the customer bill impact for low use customers can be significant.	The bill impact for those customers with natural gas space heating and for those in colder climates can be significant.	Depending on the portion of costs recovered in the first block, the customer bill impact for high volume customers can be significant.
Rate and/or revenue stability	Annual forecasting for flat rates is more accurate than other rate options. Forecast accuracy results in improved rate and revenue stability.	Compared to a flat rate, declining rate provides less utility revenue stability due to higher difficulty of forecasting the load in each block.	This rate structure provides less utility revenue stability and customer rate stability as the price differential between winter and summer months can be significant.	Compared to a flat rate, this rate structure provides less utility revenue stability due to higher difficulty of forecasting the load in each block.

22.1 Please confirm that most residential customers are likely to be familiar with inclining block rates from BC Hydro.

Response:

FEI believes that some residential customers are sufficiently familiar with inclining block rates due to their experience with BC Hydro (or FortisBC electric) rates. However, a review of BC Hydro's residential inclining block evaluation report indicates that close to 50 percent of residential customers were unaware of their rate structure,[1] meaning they did not know that an inclining rate structure is applied to their bills. A total of 31 percent of BC Hydro's customers believed they were charged under a flat rate and 17 percent did not know. This can be compared with results of the Sentis residential survey which states that 84 percent of respondents have a very clear or somewhat clear understanding of how their bill is calculated. Furthermore, in BC Hydro's survey, those who know that they are charged under inclining block rates, may not know at what level of consumption and at what time of a month their consumption may go over the first block, leading to higher customer dissatisfaction. Furthermore, the result of FEI's residential customer survey indicates that compared to block

[1] BC Hydro; Power smart Evaluation: "Evaluation of the Residential Inclining Block Rate F2009-F2012", p. vii.

rate structures, flat rates are easier to understand. The issue highlighted in the table above is that, compared to a flat rate, an inclining block rate is more complex and harder to understand and manage. These observations are supported by the evidence.

22.2 Please provide an estimate of the 'cost pressures' that would occur as a result of a change from the flat rate.

Response:

A transition from FEI's current flat rate to either a declining or inclining block rate would require material configuration changes in the Customer Information System. The efforts to configure and test the new rate structure would take approximately six months with an estimated implementation cost of $250 thousand to $350 thousand. Customer communication and education related to the change, including additional support in the call centres to address customer inquiries, would also be required. The estimated cost of business preparedness for documentation and training is $150 thousand. Customer education costs are estimated to be between $300 thousand and $500 thousand to explain the impact and rationale for the change.

22.3 Please confirm that those cost pressures would be proportional to the slope of the incline variance from flat.

Response:

FEI assumes the question refers to the bill impact of cost pressures caused by the transition from flat rates to a block rate structure. The bill impact caused by a transition from a flat rate structure to a block rate structure will depend on the monthly consumption of each customer, the consumption threshold for each block, the price difference in each block and the fixed charge amount.

22.4 Please provide FEI's 'long run incremental cost of service'.

Response:

FEI has not developed a "long run incremental cost of service" as it is not necessary for FEI's rate design. For purposes of the Application, EES Consulting provided a Review of Marginal Cost for Delivery of Natural Gas, which can be found in Appendix 4-4 of Exhibit B-1.

22.5 Please provide FEI's incremental cost of service for each of the elements in its supply stack used to meet winter peak use.

Response:

The table below shows the forecast costs for the various components of the gas supply resource stack required to meet winter peak demand, and approved via the Annual Contracting Plan. The costs are based on the forecast gross costs of the resources for 2017 as filed in the FEI 2016 Fourth Quarter Gas Cost Report, excluding any forecast mitigation that would be included when setting recovery rates, as rates are based on the normalized forecast demand and costs.

Forecast Costs of FEI's Gas Supply Resources Before Mitigation to Normalized Demand [(1)]
For The Period January to December 2017
(Amounts Shown in $000s)

	Winter Period	Summer Period	Annual
	Jan-Mar / Nov-Dec	Apr - Oct	Total 2017
Commodity	$ 218,691	$ 100,130	$ 318,821
Third Party Storage	12,701	23,840	36,541
Transportation	50,157	64,398	114,555
On-System Storage (LNG)	7,622	11,200	18,821
Totals	**$ 289,171**	**$ 199,567**	**$ 488,738**

Notes: (1) Forecast based on FEI 2016 Fourth Quarter Gas Cost Report filed on November 23, 2016.

The table shows the costs for the winter months (comprising January to March and November to December), the summer months (April to October), and the total 2017 calendar year. The commodity costs are significantly higher in the winter compared to the summer because of the additional seasonal and spot purchases that FEI transacts for to meet the winter load requirements.

22.6 Please provide FEI's average cost of service.

Response:

FEI's average cost of service can be found in the Application. Please refer to Exhibit B-1, Appendix 6-4, Schedule 7, lines 31 and 34.

22.7 Did FEI consider the use of a 'demand charge' instead of a 'seasonal rate' for Residential customers?

Response:

FEI has previously considered the possibility of introducing a demand charge for residential customers. A demand charge for residential customers will require a demand meter (i.e., a meter that can provide daily measurement). FEI's residential customers do not have demand meters. Introducing any demand charge to residential customers' bills will significantly increase the complexity of their bills. Introducing this complexity would be counter to the results of the residential customer research survey, which indicates that ease of understanding and administration is the most important rate design principle from residential customers' perspective. Additionally, the results of the jurisdictional review study show that no Canadian natural gas utility applies a demand charge to their residential customers.

22.7.1 If no, please explain why not.

Response:

Please refer to the response to CEC-FEI IR 1.22.7.

22.7.2 Could FEI implement optional Smart Meters and optional, alternative rate structures? Please explain and identify any options that FEI has considered.

Response:

Implementing optional advanced (or smart) meters may be technically possible; however, FEI anticipates the costs of such an initiative would be significant. Implementation of optional advanced (or smart) meters would require investment beyond the cost of a meter, and many of the costs for an optional implementation could be as high as for an implementation for all customer premises. Costs would include, but not be limited to:

- the meters;
- software and system development for initial implementation of the meters and ongoing meter reading;
- infrastructure to support the optional meters;
- separate bill design and production to support the optional meters and possible alternative rates; and
- ongoing administrative costs to manage the optional meters, possible alternative rates and ongoing billing.

To be cost effective, advanced meters may need to be installed on all premises, thereby reducing meter reading costs. Advanced meters could allow a rate structure with a demand charge, which has the potential to reduce energy bills for customers with better than average load factors.

22.7.2.1 If yes, please confirm that such optional rate structures would be consistent with the Clean Energy Act, Section 17, under which the Commission must consider the 'government's goal of having smart meters, other advanced meters and a smart grid…'

Response:

FEI understands the question to be referring to section 17(6) of the *Clean Energy Act*, which states:

> (6) If a public utility, other than the authority, makes an application under the Utilities Commission Act in relation to smart meters, other advanced meters or a smart grid, the commission, in considering the application, must consider the government's goal of having smart meters, other advanced meters and a smart grid in use with respect to customers other than those of the authority.

Whether an application for "optional rate structures" was an application "in relation to smart meters, other advanced meters or a smart grid" as contemplated in section 17(6) of the *Clean Energy Act* would have to be assessed based on the nature of the application at the time.

22.8 Please confirm that the Inverted Block Rate Structure would be consistent with conservation and efficiency principles.

Response:

An inverted block rate structure would be consistent with energy efficiency and conservation considerations reflected in government policies, but for natural gas distribution it would not be consistent with the economic efficiency principle. Please refer to the response to BCSEA-FEI IR 1.2.3 for more information regarding the compatibility of inverted rates with the economic efficiency principle for a natural gas distributor and reasons why FEI did not pursue an inclining block rate structure.

22.9 Please provide FEI's views as to what constitutes a 'significant' rate impact.

Response:

FEI does not refer to "significant" rate impacts in Table 7-2 of the Application. In the row titled "Customer bill impact", FEI indicates that the bill impact of declining block, seasonal and inverted block rates can be significant. Depending on the portion of costs recovered from the first block, the bill impact for low use customers in the declining block and for high volume customers in the inverted block could be more than 10 percent. Similarly, rates set for a seasonal rate structure could lead to bill impacts of upwards of 10 percent for customers living in colder climates and those with natural gas space heating loads.

22.10 Could seasonal rates more accurately reflect the cost of serving customers? Please explain why or why not.

Response:

Yes. FEI is a winter peaking utility. As stated in Table 7-2 as shown in the preamble to the IR, a seasonal rate can be used as a proxy for a demand charge to ensure that the costs of serving peak winter demands are allocated to those most responsible for causing them. In practice, the calculation of price differential between winter and summer months can impact the effectiveness of seasonal rates in providing the right price signals. Seasonal rates are also more complex than flat rates and do not fare as well as flat rates on customer understanding and acceptance.

22.11 Please confirm that there is no explicit regional 'price' differential using seasonal rates. Rather, there is likely to be a consumption differential which is controlled by the customers.

Response:

FEI confirms that under a seasonal rate option, there will be no "explicit" regional price differential. However, in practice, customers in northern regions of FEI's service territory with longer and colder winters may pay a higher average rate (due to higher use during winter months) than customers in other regions, thus creating an "implicit" regional rate differential. As explained on page 7-11 of the Application, a seasonal rate differential was applied to BC Gas' rates from 1994 to 1998. Despite the theoretical appeal, the seasonal rates did not perform well in respect to the rate design principle of customer understanding and acceptance. Some customer groups objected to this rate structure and claimed that seasonal rates unfairly impact the customers who are located in colder regions of the province. Following these complaints and a review process, the Commission decided to terminate the seasonal differential. This experience indicates that even though there was no "explicit" regional price differential, the customers' perception of such a regional differential was sufficient to lead to the ultimate termination of seasonal rates after only 4 years.

FEI does not entirely agree with the second statement in the question which expresses that the consumption differential is controlled by the customers. Customers living in northern regions of FEI's territory for example have no control over the longer and colder winters and, despite their best efforts, may not be able to consume at the same level as customers in warmer regions of

FEI's service area. Therefore, while customers have some control over their consumption, they do not have absolute control.

22.12 Please explain why annual forecasting for a flat rate is more accurate than other rate options. Please provide FEI's evidence for this statement.

Response:

Please note that the accuracy of annual forecasting refers to revenue forecasting in general which is affected by the dynamics between load forecasting and the applied rate structure and not just the accuracy of annual load forecasting.

Setting the rates under a flat rate structure requires customers' annual consumption forecasts. From a rate making perspective, it is the accuracy of the annual load forecast and not the accuracy of forecast in individual months that is important (since load forecasts are prepared using normalized weather). Under a block rate structure, however, customers' consumption would need to be forecast for each month (because the rate is specific to the block in each month) and the accuracy of monthly load forecasts has a greater impact on the accuracy of annual revenue forecasts. This adds another layer of complexity to annual forecasting.

As explained in response to CEC-FEI IR 1.4.1, with flat rates, revenue will vary proportionally with changes in consumption – each gigajoule will be billed at the same rate for a specific rate class. With a block rate structure, the impact of a load variance in one block is higher than in the other. This has the potential to lead to a greater variation in revenue (and in rates) as a result of changes in consumption. For instance, under an inclining block rate structure, if the actual throughput in the second block is 1 GJ more than the forecast volume, the impact of this 1 GJ variance on revenue surplus is more significant than a similar 1 GJ variance under flat rates because the rate in the second block is higher. Therefore, a block rate structure could increase revenue and rate instability.

22.13 Please elaborate on how forecast accuracy results in improved rate and revenue stability, and consider FEI's current status as operating under PBR.

Response:

Please refer to the responses to CEC-FEI IRs 1.22.12 and 1.4.1. Revenue forecasting is the same whether FEI is operating under Cost of Service or under its current PBR.

22.13.1 Could such instability be addressed with deferral account? Please explain why or why not.

Response:

Deferral accounts do not eliminate the variances; therefore, it is preferable to adopt options that reduce the variance in the first place. However, it is true that deferral accounts can mitigate the immediate impact of variances and smooth out their impacts on rates.

23. Reference: Exhibit B-1, page 7-16

> **7.4.5 Proposed Rate Structure Option**
>
> Based on the discussion above, FEI believes that its existing flat rate structure provides the best balance of rate design considerations for residential customers and that there is no basis to segment this rate schedule further as there is little statistical evidence to indicate that consumption data is sufficient to distinguish between low and high efficiency customers. FEI's residential customers are already familiar with this rate structure, flat rates are simple to administer and easy to understand and provide more stability in terms of both utility revenues and customers' rates. The customer research survey results also show that the flat rate structure is preferred by the majority of residential customers (Section 7.4.4). Furthermore, as indicated in Section 7.6, the flat rate structure has been adopted by the majority of Canadian natural gas utilities for their residential customers.

23.1 Please discuss whether or not FEI considers customer preference in other rate classes, and if so, how that is and has been factored in both now and in the past.

Response:

Yes. Similar to the residential rate class, FEI did consider customer preferences in other rate classes as an input to its rate design proposals. The workshops held prior to the filing of the Application as a part of FEI's robust stakeholder engagement process provided a context in which stakeholders representing industrial and commercial customers were able to express their preferences and feedback regarding the rate design issues discussed in the workshops. FEI considered the stakeholder feedback when determining the rate design proposals in the Application.

23.2 Does FEI have commercial customer survey results?

Response:

No. There are almost 900,000 residential customer accounts and FEI's goal with the customer survey was to gain some insight into this large group of customers. Therefore, FEI considered it was reasonable to conduct a province-wide survey to have a broad representation of residential customers' preferences, and to inform FEI's proposals for the residential rate class.

23.2.1 If not, please explain why not.

Response:

Please refer to the response to CEC-FEI IR 1.23.2.

23.2.2 If yes, please provide these results.

Response:

Please refer to the response to CEC-FEI IR 1.23.2.

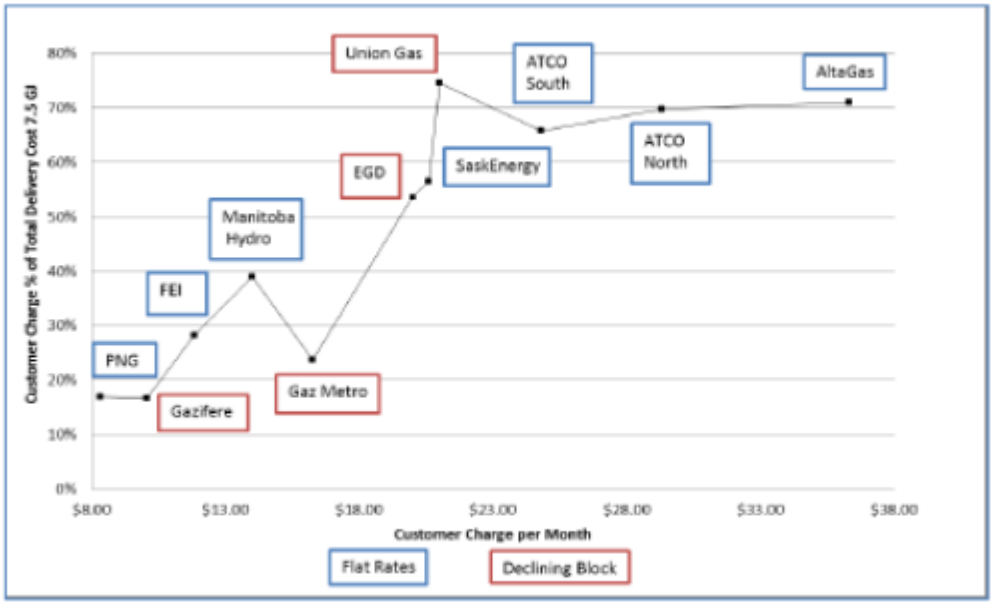
23.3 What options does FEI have for distinguishing between high and low efficiency residential customers? Please explain.

Response:

FEI's residential customers do not have demand meters and therefore FEI cannot calculate individual customer's load factors reliably. Without demand meters, FEI's best option to distinguish between high and low efficiency residential customers would be to apply a seasonal price differential to its rates. Please also refer to the response to CEC-FEI IR 1.22.10.

24. Reference: Exhibit B-1, page Exhibit B-1, page 7-20

Figure 7-10: Residential Rate Structures for Various Canadian Natural Gas Distributors[113]



24.1 FEI's residential rates are some of the lowest in the country for flat rates. Please explain what circumstances create this situation.

Response:

Figure 7-10 in the preamble to the IR shows that FEI's Basic Charge (referred to as customer charge), as well as the ratio of FEI's customer charge to total delivery charge for a residential customer with an average monthly use of 7.5 GJ[2], are among the lowest in the country. Figure 7-10 does not show that total delivery charges are among the lowest in the country.

The location of utilities on the Y-axis of Figure 7-10 can change somewhat based on the actual average monthly consumption of their residential customers. For instance, if the average monthly use per customer is higher than 7.5 GJ (this is the case for utilities such as Union Gas), the ratio of monthly customer charge to total delivery charge will decrease.

Figure 7-10 indicates that FEI's Basic Charge is lower than the majority of Canadian natural gas utilities. The low customer (Basic) charge is not a function of lower customer-related costs facing FEI compared to other utilities, but rather the result of previously approved rate designs and the gap between fixed and volumetric cost recovery. This has resulted in the customer charge collecting only 44 percent of customer-related costs.

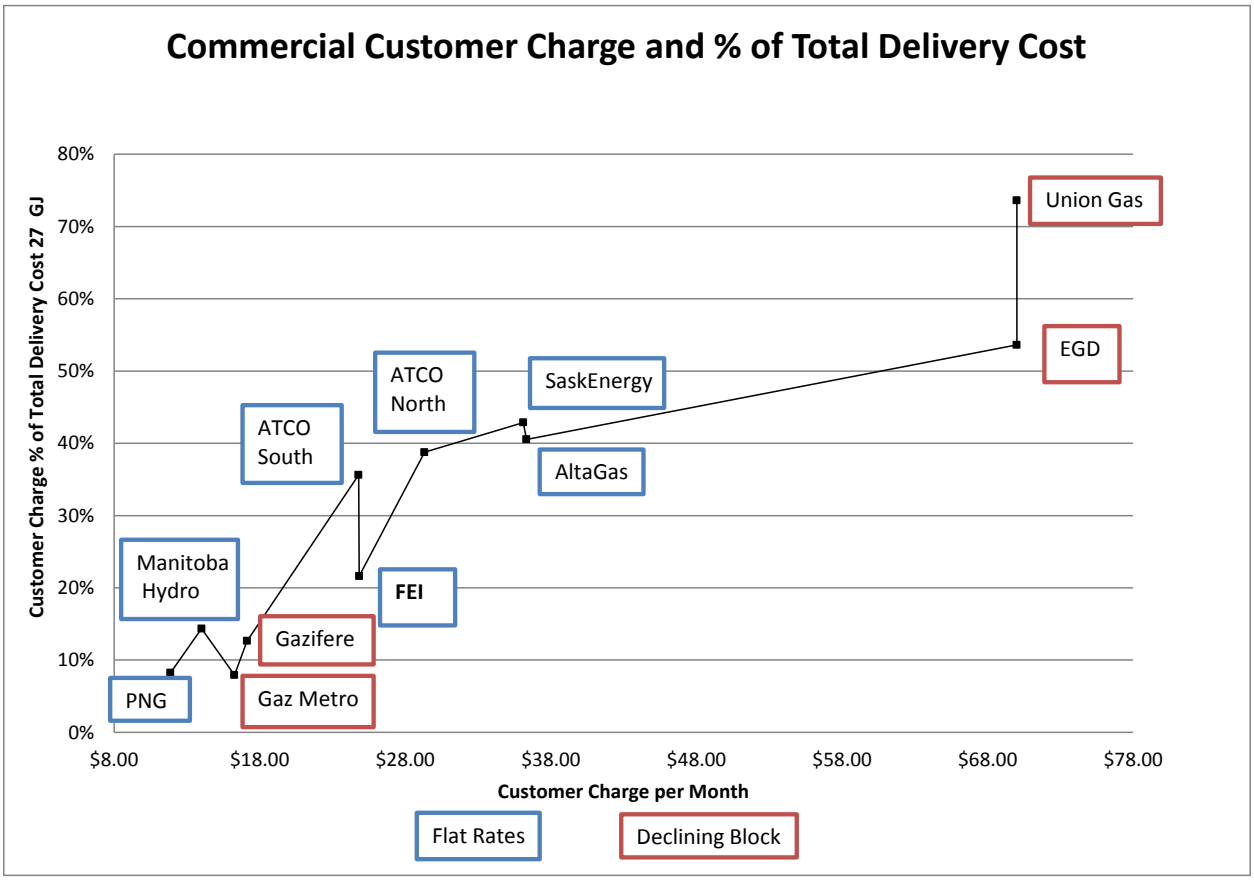
[2] The presentation of data with a specific monthly consumption amount makes the comparison of the basic charges amongst the utilities more meaningful.

24.1.1 Please provide a similar graphic for commercial rates.

Response:

EES provides the following response.

The following chart provides the information requested for an average commercial customer.



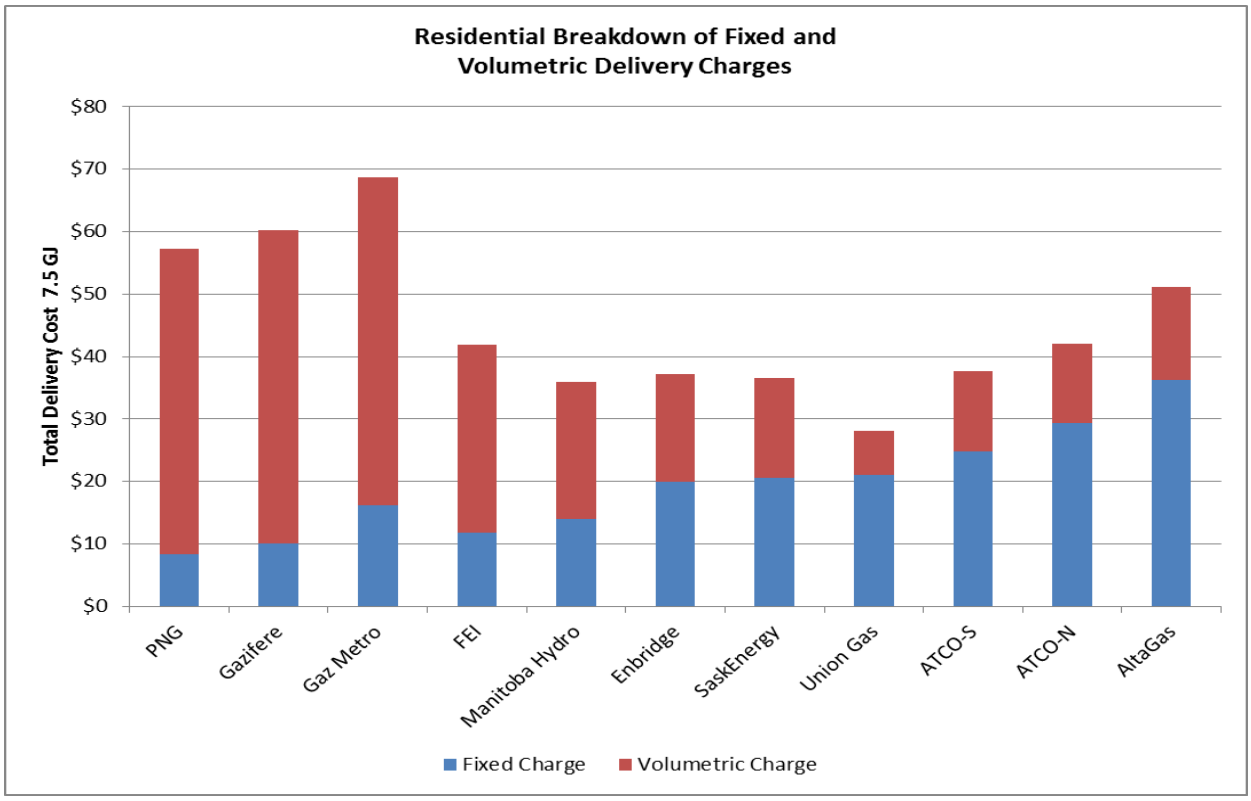
24.2 Please break down this graphic by fixed charges and commodity rates to the extent the information is available.

Response:

FEI assumes that the question refers to volumetric delivery rates and not the commodity rates. The fixed customer charges are already provided in the chart along the x-axis.

EES provides the following response.

The following bar chart provides a break-down of fixed customer charge and volumetric delivery charge for a residential customer with an average monthly consumption of 7.5 GJ. For a more detailed break-down of fixed and volumetric charges, please refer to Appendix 7-2.



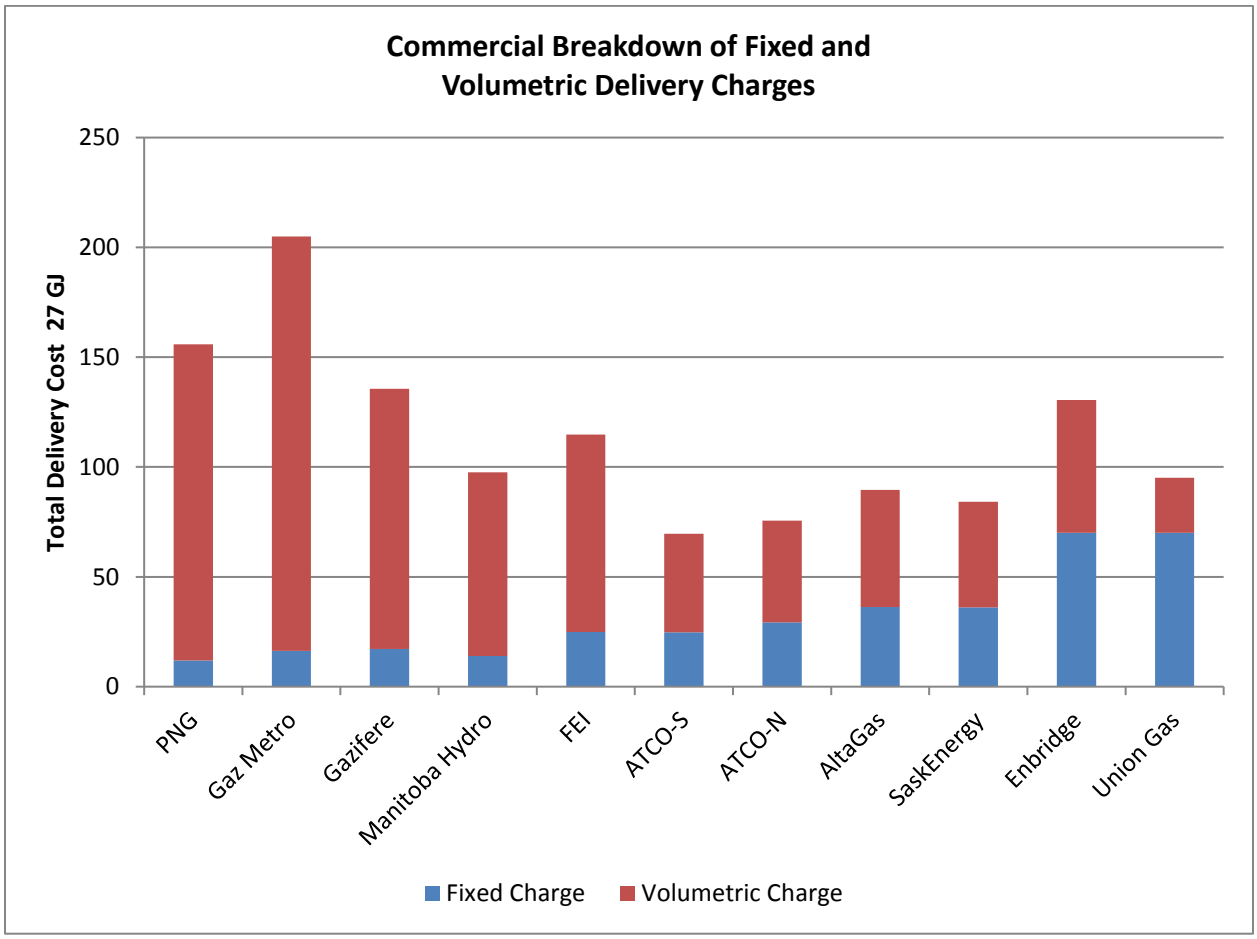
24.2.1 Please provide similar graphics for commercial rates.

Response:

EES Consulting provides the following response.

The following bar chart provides a break-down of fixed customer charge and volumetric delivery charge for a commercial customer with an average monthly consumption of 27 GJ.

1


Commercial Breakdown of Fixed and Volumetric Delivery Charges
Total Delivery Cost 27 GJ
250
200
150
100
50
0
PNG
Gaz Metro
Gazifere
Manitoba Hydro
FEI
ATCO-S
ATCO-N
AltaGas
SaskEnergy
Enbridge
Union Gas
Fixed Charge
Volumetric Charge

2
3
4
5

25. Reference: Exhibit B-1, page 7-19

> 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 militate against making significant changes to the Basic Charge are:
>
> - 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.

25.1 Would an increase in the basic charge, combined with an inclining block rate structure for the volumetric delivery rate charge provide both a fairer cost recovery and support for energy efficiency and conservation principles?

Response:

The response to this question would depend on the design of the inverted rate structure and the magnitude of the increase in the Basic Charge. In principle, for a fairer cost recovery under an inclining block rate scenario, the Basic Charge should increase more than FEI's proposed 5 percent revenue-neutral increase, which would be counter to the energy efficiency and conservation principles. Please also refer to the response to BCSEA-FEI IR 1.2.3 for a discussion of FEI's rationale for not pursuing an inclining-block rate.

FEI notes that, in its recent Decision on BC Hydro's rate design (Order G-5-17), the Commission decided to maintain BC Hydro's existing flat rate structure for Small General Service (SGS) rate schedule, while increasing the SGS basic charge recovery of customer-related costs (from 33 percent to 45 percent). The Commission also decided to replace the existing inclining block rates of Medium General Service and Large General Service rate schedules with flat rate structure. This is consistent with FEI's continued use of flat rates and proposal to increase the recovery of fixed costs with fixed charges.

25.1.1 If not, please explain why not.

Response:

Please refer to the response to CEC-FEI IR 1.25.1

26. Reference: Exhibit B-1, page 7-20

> Four of the utilities presented in the above figure, ATCO Gas, Alta Gas, Union Gas and Gaz Metro, do not have a separate rate schedule for residential customers. Instead, their residential customers are part of a more heterogeneous group segmented based on consumption as low use[114]. This distinction offers a partial explanation for the significantly higher basic charges for these utilities, as commercial customers traditionally have higher basic charges than separately administered residential rate schedules. Similarly, it is important to note that residential natural gas customers in Quebec and Ontario have a declining block rate structure. A declining block rate structure is more favorable to customers with higher monthly consumption levels since the unit cost ($/GJ of consumption) will decline after a certain monthly consumption threshold is surpassed.
>
> [113] PNG, Union Gas and ATCO gas have regional rates. For PNG, the average of all rates is used for presentation purposes. For Union Gas only M1 rate schedule (South Ontario region) is presented.
> [114] Less than 1200, 419, 1912 and 5238 GJ/year for ATCO Gas, Gaz Metro, Union Gas and Alta Gas respectively.

26.1 Please provide a qualitative and quantitative comparison of residential and commercial customers identifying the characteristics that suggest the appropriateness of having separate rate schedules.

Response:

EES Consulting provides the following response.

The cost of serving residential and commercial customers differs as a result of differences in use per customer, load factor and the facilities that must be installed for different types of customers.

Customer-related costs differ between residential and commercial customers because of the difference in the type and cost of meters installed, as well as the complexity of meter reading and billing. Customer-related costs differ by class, with a cost of $0.947 per customer/day for RS 1, $1.329 per customer/day for RS 2 and $3.111 per customer/day for RS 3/23.

Demand-related costs also differ due to the load factors associated with each class. Demand-related costs are $2.719 per GJ for RS 1, $3.080 per GJ for RS 2 and $2.664 per GJ for RS 3/23.

Because of these cost differences, there is a justification for maintaining separate classes with the cost of service study and separate rate schedules.

26.2 Please discuss whether it would or would not be feasible for FEI to eliminate the Residential rate schedule and utilize a rate structure based on consumption, as is done by ATCO gas, Alta Gas, Union Gas and Gaz Metro.

Response:

EES Consulting provides the following response.

It would be feasible to have one rate schedule pertaining to residential and commercial use provided that the rate structure would be a declining block structure to capture the differences in costs that result from differences in use per customer and load factor. It would be difficult to adequately capture the customer-related costs in the customer charge for a combined residential/commercial customer class due to the cost differences between the classes.

The distinguishing customer and cost characteristics of residential and commercial customers justify the current customer segmentation. In general, segmenting customers into more homogenous groups improves the cost causation among various customers and is supported by rate design principles. However, this should be balanced by the need for simplicity, as well as costs associated with creating new rate classes. FEI's residential and commercial customers are already segmented into more homogenous groups. For the above-mentioned utilities that have had consumption-based rates classes, the creation of a new residential customer class would result in significant administrative and cost challenges which prevent them from pursuing such an initiative.

FEI adds the following to the response:

There are other practical reasons for keeping residential and commercial customers separate, since there is different treatment for taxes and levies in some cases for residential and commercial accounts. For example, residential accounts are exempt from provincial sales tax, while commercial accounts are not.

26.3 Please provide a list of the advantages and disadvantages of a rate structure that distinguishes customers based on volume rather than customer type.

Response:

A rate structure that distinguishes customers based on volume rather than customer type would have the following advantages and disadvantages:

Advantages

- Simplifies the number of rates offered
- Treats all customers the same given a specific GJ usage level

Disadvantages

- Some tax measures differentiate between utility customers based on customer type (such as the sales tax exemption for residential customers). Adopting a volume-based customer segmentation approach therefore may hinder the implementation of these measures.
- On some occasions in the past, rate riders have targeted specific customer classes. The ability to do this in the future would also be hindered by a combined rate class with a volume-only differentiation.
- Does not capture the differences in customer-related costs between the classes.
- If a flat rate structure is adopted, it is difficult to capture differences in the demand-related cost associated with different load factors to serve large customers of the same usage level.
- If a declining block structure is adopted to account for differences in load factor and in the demand-related cost to serve, this would provide a price signal encouraging higher consumption for all customers, which could be viewed as inconsistent with government policy to encourage conservation. Please refer to Table 7-2 of the Application for other disadvantages of a declining block rate related to ease of understanding and administration, customer bill impact and rate and/or revenue stability.

26.4 Please provide an overview with FEI's best estimates as to how residential and commercial customer rates would be impacted by such a change.

Response:

A combined customer class including residential and commercial customers would not be appropriate based on the different characteristics of these groups as described in Sections 7 and 8 of the Application. However, FEI will endeavor to answer, at a high level, how FEI's residential and commercial customers would be impacted under such a proposal. Assuming that the combined group's allocated costs equals the sum of the residential and commercial customer's allocated costs in the COSA and a flat rate structure is adopted, residential customers would see a higher basic charge because the commercial customers' higher customer costs would pull up the average. The volumetric charge could possibly be higher for the commercial customers because the residential customers' lower load factors attract more

1 demand costs than the commercial customers would on their own. Please also refer to the
2 response to CEC-FEI IR 1.26.3.

3

27. Reference: Exhibit B-1, page 7-22

> Any rate design proposal should consider the bill impact to customers and should be implemented in a way that avoids rate shock to customers.
>
> The table below provides the Basic Charge and the volumetric Delivery Charge before rebalancing[115], after rebalancing (including changes caused by rate design proposals in other rate schedules)[116], and with rebalancing and also a 5% increase in the daily Basic Charge.

Table 7-7: Different Rate Scenarios for Residential Rate Schedule

Title	COSA before Rebalancing	COSA after Rebalancing	5% Increase in Basic Charge and offsetting Decrease in Delivery Charge
Daily Basic Charge ($/day)	0.3890	0.3890	0.4085
Delivery Charge ($/GJ)	4.821	4.832	4.746

27.1 Please provide FEI's definition of 'rate shock'.

Response:

Please refer to the response to BCUC-FEI IR 1.3.1.

27.1.1 Please provide evidentiary support for this definition if available.

Response:

Please refer to the response to CEC-FEI IR 1.27.1.

27.2 What are the kinds of costs that should be considered as fixed customer charges versus variable delivery charges.

Response:

From a cost causation perspective, customer-related costs should be collected with a fixed customer charge, demand-related costs should be collected through a demand charge and energy-related costs should be collected through a volumetric charge. However, cost causation is just one of the rate design considerations and, as discussed in Section 5 of the Application,

rate design should strive to strike a balance among various competing rate design considerations. In the COSA there are both costs that are directly related to serving customers and general costs that are allocated across the various functions. Some of the customer-related costs in the COSA include:

- Customer contact, billing and administration costs;
- Energy Solutions and External Relations costs;
- Information Systems costs;
- An allocation of General Plant and Admin costs; and
- The customer component of the distribution system costs (minimum system).

27.2.1 Please provide a calculation of a basic charge using the full amount of the fixed customer costs to establish the basic charge.

Response:

A fixed daily basic charge of $0.8905 per day ($27.10 per month)[3] for RS 1 would collect the customer-related costs for which RS 1 customers are allocated in the COSA. To establish the rate, FEI multiplied the COSA customer-related costs by the M:C ratio; this is necessary as the delivery margin for RS 1 is 94.4 percent of the allocated costs as is shown in the COSA on schedule 1.

Line	Rate Schedule 1	Amount	Reference
1	COSA Customer Related Costs	$ 305,517,603	Appendix 12. Schedule 4, Line 39, Rate 1 x 1000
2	M:C ratio	94.4%	Appendix 12, Schedule 1, Rate 1, Line 32
3	Customer Related Costs for recovery	$ 288,375,971	Line 1 x Line 2
4	Customers	886,652	Appendix 12, Schedule 7, Rate 1, Line 6
5	Days/Year	365.25	
6	Daily Basic Charge $/Day	0.8905	Line 3 / Line 4 / Line 5

[3] Table 7-5.

27.2.2 Please provide the percentage of total fixed costs relevant for basic charges that the existing and proposed basic charge would collect.

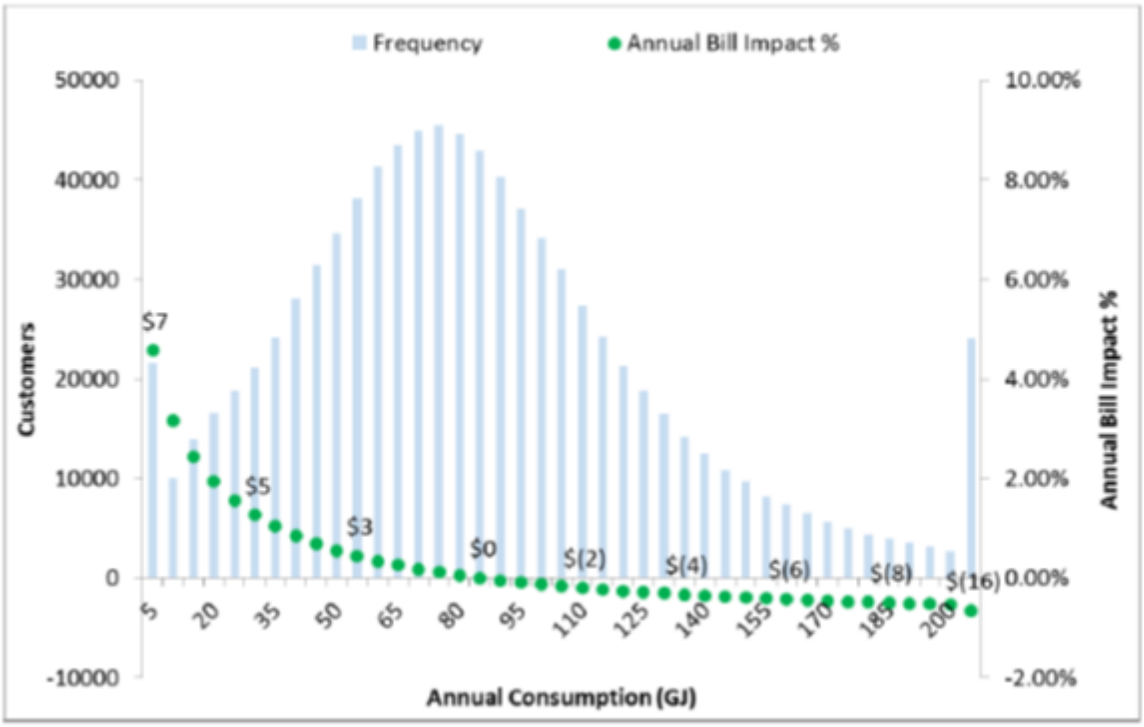
Response:

Assuming that the relevant fixed charges to be recovered through the basic charge equal the customer related cost from the COSA, the existing RS 1 basic charge of $0.3890 per day ($11.84 per month) recovers approximately 44 percent of these costs and FEI's proposed basic charge of $0.4195[4] per day ($12.77 per month) recovers approximately 47 percent of these costs.

[4] Approvals Sought Section 2.2, 2, Residential Rate Schedules $0.4085 + $0.011.

28. Reference: Exhibit B-1, page 7-22

Figure 7-11: Customer Bill Impact[118]



28.1 How many customers will receive bill increases?

Response:

Based on the consumption and customers included in Figure 7-11, approximately 517 thousand customers would see bill increases and approximately 370 thousand customers would see bill decreases.

28.2 How many customers will receive bill decreases?

Response:

Please refer to the response to CEC-FEI IR 1.28.1.

28.3 How many customers will receive fairer bills based on Bonbright fair cost allocation principles? Please provide an explanation.

Response:

The proposed 5 percent revenue neutral increase to Basic Charge will improve the intra-rate schedule fairness among all RS 1 customers.

29. Reference: Exhibit B-1, page 8-7

Table 8-2: Multi Jurisdiction Review of Commercial Rate Schedules

Company	Description	Eligibility	Type
Small Commercial			
FEI	Small Commercial	<2,000 GJ	Flat Rate
PNG	Small Commercial	<5,500 GJ	Flat Rate
AltaGas	Small General	<5,326 GJ	Flat Rate
Sask Energy[130]	Small Commercial	<3,825 GJ	Flat Rate
Manitoba Hydro	Small General	<535 GJ	Flat Rate
Gaz Metro	Distribution	<419 GJ	Declining
Large Commercial			
FEI	Large Commercial	>2,000 GJ	Flat Rate
PNG	Large Commercial	>5,500 GJ	Flat Rate
ATCO	Mid Use	1,200 – 8,000 GJ	Flat Rate
AltaGas	Large General	>5,326 GJ	Flat Rate
Sask Energy	Large Commercial	3,825 – 25,245 GJ	Flat Rate
Manitoba Hydro	Large General	536 – 26,010 GJ	Flat Rate
Union Gas	Large General	>1,712 GJ	Declining
Enbridge	General	No limit	Declining

29.1 Under what tariff does ATCO gas serve customers under 1200 GJ?

Response:

EES Consulting provides the following response.

Customer with consumption below 1200 GJ per year would be served under the Low Use Delivery Service Rates.

29.1.1 Please provide the rate structure for these customers.

Response:

EES Consulting provides the following response.

The following is the current ATCO rate structure for customers under 1200 GJ per year.

ATCO Gas North

Fixed Delivery Charge (FDC): $0.973/day

Variable Delivery Charge (VDC):	$0.905/GJ
Transmission Service Charge (TSC):	$0.925/GJ*
Total Variable Delivery Charge:	$1.830/GJ

ATCO Gas South

Fixed Delivery Charge (FDC):	$0.823/day
Variable Delivery Charge (VDC):	$0.806/GJ
Transmission Service Charge (TSC):	$0.925/GJ*
Total Variable Delivery Charge:	$1.731/GJ

29.2 Under what tariff does Union Gas serve customers under 1,712 GJ?

Response:

EES Consulting provides the following response.

Customers with usage under 50,000 m3/year are served under Rate M1 in the Southern region.

29.2.1 Please provide the rate structure for these customers.

Response:

EES Consulting provides the following response.

The following shows the current delivery rate for Union Gas' M1- South rate.

First 100 m3	8.0501 ¢/m³
Next 150 m3	7.8090 ¢/m³
All Over 250 m3	7.1860 ¢/m³
Delivery Price Adjustment	0.0000 ¢/m³
Monthly Charge	$21.00

30. Reference: Exhibit B-1, page 8-7

> Table 8-2 shows that the threshold between small and large commercial customers ranges from 419 GJ/year for Gaz Metro to 5,500 GJ for Pacific Northern Gas (PNG). The 2,000 GJ threshold between RS 2 and RS 3/RS 23 used by FEI is roughly in the middle of this range. Consistent with FEI, most of these utilities use a flat rate structure for commercial customers.
>
> The multi-jurisdiction review of the commercial customer rates shows that FEI's use of a flat rate structure is consistent with the commercial rate structure of most other utilities and also shows that FEI's current 2,000/year threshold is within the range of thresholds used by other utilities.

30.1 Has FEI conducted any commercial customer surveys to determine the preferred threshold?

Response:

FEI has not seen a need to conduct a survey with commercial customers to determine if they have a preferred threshold to distinguish between Small Commercial and Large Commercial. Explaining the concept of a threshold and the implications of changing the threshold to customers through a survey would be quite complex. FEI discussed the threshold and took feedback on the options to change the threshold between small and large commercial customers during the stakeholder workshops conducted in 2016 prior to filing the Application. The CEC actively participated in the workshops, where the concept of the threshold and options were discussed in detail. The idea of conducting a survey on this topic was not raised in the workshops.

30.1.1 If not, why not.

Response:

Please refer to the response to CEC-FEI IR 1.30.1.

30.1.2 If so, please provide.

Response:

Please refer to the response to CEC-FEI IR 1.30.1.

31. Reference: Exhibit B-1, page 8-8

8.3.2.1 Customer Bill Frequency

FEI has conducted a bill frequency analysis for RS 2 and RS 3/RS 23, which considers the annual consumption of the customers in each rate schedule. Figures 8-6 and 8-7 below show the 2015 annual consumption for RS 2 and RS 3/RS 23 customers, respectively.

Figure 8-6: Small Commercial Customer Bill Frequency

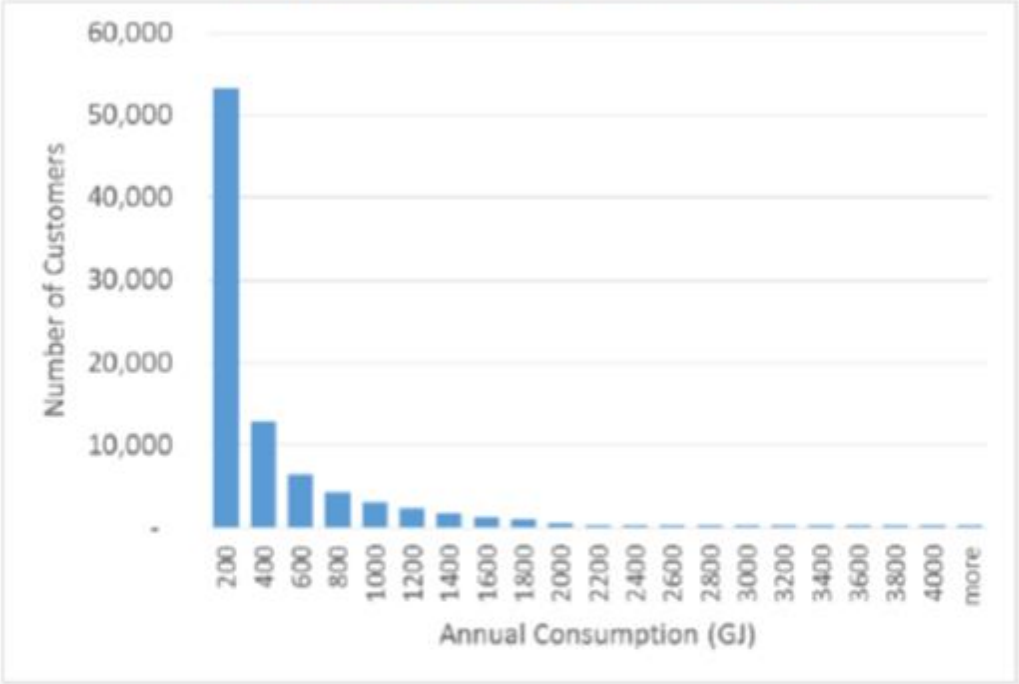


Figure 8-6 shows that approximately 72,000 (or approximately 85%) of the 85,000 small commercial customers use less than 600 GJ/year and approximately 84,000 (or 99%) customers use less than 2,000 GJ/year. There are approximately 600 customers whose annual consumption is greater than, the 2,000 GJ threshold. Many of the RS 2 customers consuming more than the 2,000 GJ threshold are either new customers whose annual consumption estimates were too low, or they are customers who have had a material change to their operations during the year. FEI reviews the customer consumption history annually to ensure that customer consumption meets the tariff requirements and will transfer customers to the appropriate rate schedule as necessary.

31.1 Please provide the above in tabular form, and break down those commercial customers consuming under 600 GJ into 50 GJ increments.

Response:

The following table presents the number of Small Commercial (RS 2) customers in increments of 50 GJ from 0 GJ to 600 GJ and then in 200 GJ increments from 600 GJ to 4,000 GJ and finally the number of customers that consumed more than 4,000 GJ.

Volumetric Blocks	**0 - 50 GJ**	**50 - 100 GJ**	**100 - 150 GJ**	**150 - 200 GJ**	**200 - 250 GJ**	**250 - 300 GJ**
# of Customers	27,554	13,752	8,423	5,616	4,034	3,287
Volumetric Blocks	**300 - 350 GJ**	**350 - 400 GJ**	**400 - 450 GJ**	**450 - 500 GJ**	**500 - 550 GJ**	**550 - 600 GJ**
# of Customers	2,639	2,215	1,846	1,662	1,430	1,266
Volumetric Blocks	**600 - 800 GJ**	**800 - 1000 GJ**	**1000 - 1200 GJ**	**1200 - 1400 GJ**	**1400 - 1600 GJ**	**1600 - 1800 GJ**
# of Customers	4,028	3,041	2,148	1,622	1,061	677
Volumetric Blocks	**1800 - 2000 GJ**	**2000 - 2200 GJ**	**2200 - 2400 GJ**	**2400 - 2600 GJ**	**2600 - 2800 GJ**	**2800 - 3000 GJ**
# of Customers	318	137	58	37	22	15
Volumetric Blocks	**3000 - 3200 GJ**	**3200 - 3400 GJ**	**3400 - 3600 GJ**	**3600 - 3800 GJ**	**3800 - 4000 GJ**	**> 4000 GJ**
# of Customers	9	8	4	8	1	32

31.2 Please provide a comparison of a bill for customers consuming 100 GJ under both residential and small commercial tariffs.

Response:

At 100 GJ, using the proposed Basic Charge and Delivery charge and the current effective rate for Storage and Transport, and Commodity, the annual bill for a Residential customer is $929.70 and for a Small Commercial customer is $1,019.84. Please see the table below for the calculation of the annual bill.

Particulars	Residential	Small Commercial
Proposed Basic Charge $ / Day	$0.4085	$0.9485
X Number of Days	365.25	365.25
Basic Charges	$149.20	$346.44
Annual Volume (GJ)	100	100
Proposed Delivery Charge $ / GJ	$4.746	$3.664
Current Gas Costs Effective April 1, 2017		
Storage & Transport $ / GJ	$1.009	$1.020
Commodity $ / GJ	$2.050	$2.050
Total Volumetric Charges $ / GJ	$7.805	$6.734
Volumetric Charges	$780.50	$673.40
Total Annual Bill	$929.70	$1,019.84

31.3 Please provide a comparison of a bill for customers consuming 200 GJ under both residential and commercial tariffs.

Response:

At 200 GJ, using the proposed Basic Charge and Delivery charge and the current effective rate for Storage and Transport, and Commodity, the annual bill for a Residential customer is $1,710.20 and for a Small Commercial is $1,693.24. Please refer to the following table for the calculation of the annual bill.

Particulars	Residential	Small Commercial
Proposed Basic Charge $ / Day	$0.4085	$0.9485
X Number of Days	365.25	365.25
Basic Charges	$149.20	$346.44
Annual Volume (GJ)	200	200
Proposed Delivery Charge $ / GJ	$4.746	$3.664
Current Gas Costs Effective April 1, 2017		
Storage & Transport $ / GJ	$1.009	$1.020
Commodity $ / GJ	$2.050	$2.050
Total Volumetric Charges $ / GJ	$7.805	$6.734
Volumetric Charges	$1,561.00	$1,346.80
Total Annual Bill	$1,710.20	$1,693.24

32. Reference: Exhibit B-1, page 8-14

Table 8-4: Comparison of Fixed Costs and Fixed Charge Recoveries

Rate Schedule	Current Monthly Basic Charge[102]	Allocated Customer Cost from COSA ($/Month)	Basic Charge Percent of Customer Related Costs
RS 2 – Small Commercial	$24.84	$40.26	62%
RS 3/23 – Large Commercial	$132.52	$258.41	51%

As shown in the table above, the Basic Charge for both RS 2 and RS 3/RS 23 is at least half of FEI's customer allocated costs. The rate design principle to fairly apportion costs would suggest that FEI move the Basic Charge upwards to be in closer alignment with FEI's customer costs.

However, factors that militate against making significant changes to the Basic Charge are:

- At a level of 62% and 51% for RS 2 and RS 3/RS 23 respectively, FEI's commercial customer related costs are reasonably well recovered by the Basic Charge;
- Government energy efficiency and conservation policies discourages higher fixed charges;
- Increasing the Basic Charge would result in bill impacts and rate instability for commercial customers.

Based on these competing principles and considerations, FEI believes that the basic charges provide a reasonable recovery of FEI's commercial customer allocated fixed costs.

32.1 Does FEI consider 'at least half of FEI's allocated costs' to be a threshold of reasonableness? Please explain why or why not.

Response:

FEI considers the percentage of Basic Charge revenue compared to allocated customer cost as appropriate for RS 2 and RS 3/23. These percentages are higher than the corresponding percentage for residential customers. Recovering the balance of allocated customer costs through the volumetric charge leaves room for the commercial rate structures to have price signals that accommodate policy objectives such as energy conservation and efficiency. FEI did not intend "at least half" to be a threshold of reasonableness, but made the statement to confirm that commercial basic charges are recovering a significant portion of the allocated customer costs.

Please refer to the response to BCUC-FEI IR 1.23.3 for a discussion on the factors FEI used to derive rates for RS 2 and RS 3/23.

32.2 Please confirm that increasing the basic charge and lowering the delivery charge could be managed to reduce customer impacts and rate instability for customers.

Response:

Not confirmed. Increasing the Basic Charge by a large amount and lowering the Delivery Charge will cause rate instability for customers as compared to their existing rates. Also, lowering the Delivery Charge while increasing the Basic Charge for the purpose of managing customer impacts is counter to government policy objectives, such as energy conservation and efficiency.

32.2.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC-FEI IR 1.32.2.

33. Reference: Exhibit B-1, page 8-15

> **8.5 *PRINCIPLE BASED REVIEW OF RATE DESIGN***
>
> The principles adopted by FEI for its rate design are presented in Section 5 of the Application. As explained in that section, different rate design principles may have varying levels of importance for different rate schedules. Rate design should strive to strike a balance among competing rate design principles based on the specific characteristics of customers in each rate schedule.
>
> Based on FEI's examination of each element of the commercial rate design as discussed above, the commercial rate structure works well in many respects. In particular, the customer segmentation and flat rate structure with a basic and delivery charge remains appropriate.

33.1 Please elaborate on how the importance of rate design principles differ between residential and commercial and provide specifics as to which rate design principle(s) are more and those which are less important for each rate class.

Response:

The rate design principles all apply to both the residential and commercial classes. The balancing of those principles may differ between rate classes based on the cost components developed in the COSA model and other distinguishing characteristics of each customer group.

Avoidance of undue discrimination would be a more important factor for commercial customers because there is more than one commercial rate schedule, and specifically with respect to the threshold and cross-over points between RS 2 and RS 3. The intersection between RS 3/23 and RS 5/25 is another point where this principle would apply.

34. Reference: Exhibit B-1, page 8-18

> As shown above, moving the segmentation threshold down to the 1,000 GJ/year level would result in considerable changes to the annual energy, average customer use and customer load factor of the commercial rate schedules. The annual energy would reduce by 33% for RS 2 and increase by 34% for RS 3/RS 23. The load factor for RS 2 would drop from 30.7% to 29.1%, similarly affecting FEI's cost allocation among all customer rate schedules. Lastly, the movement of RS 2 customers to RS 3 would cause approximately $2.3 million more revenue to be received under RS 3 than lost from RS 2, which would need to be considered in the overall revenue rebalancing analysis.
>
> The significant customer disruption caused by moving customers representing approximately 1/3 of the entire demand within the rate schedule is not supported by the rate design principles of rate and revenue stability and is sufficient to exclude this option from further consideration.

34.1 Please provide the expected impacts for the COSA revenue to cost ratios for Rate Schedule 2 and 3 if the segmentation threshold were moved to the 1,000 GJ/year level.

Response:

If the segmentation threshold were moved to 1,000 GJ per year, the RS 2 R:C ratio would decrease by 5.1 percent to 97.1 percent and the RS 3/23 R:C ratio would increase by 1.7 percent to 105.3 percent.

34.2 Please provide the expected impacts for the COSA revenue to cost ratios for Rate Schedule 2 and 3 if the segmentation threshold were moved to the 1,400 GJ/year level.

Response:

If the segmentation threshold were moved to 1,400 GJ per year, the RS 2 R:C ratio would decrease by 2.0 percent to 96.6 percent and the RS 3/23 R:C ratio would increase by 0.9 percent to 104.5 percent.

35. Reference: Exhibit B-1, page 8-20 and page 8-11

The economic cross over point can be aligned with the 2,000 GJ threshold by simultaneously raising the Basic Charge for both RS 2 and RS 3/RS 23 and lowering the Delivery Charge for RS 2 and raising the Delivery Charge for RS 3/RS 23. These rate adjustments can be calculated to achieve revenue neutrality for the combined RS 2, RS 3 and RS 23 revenues.

The effects of these changes on RS 2 and RS 3 rates are represented by the dashed lines in Figure 8-12 below. The net effect of these adjustments is for the dashed lines to now cross at the 2,000 GJ threshold.

Figure 8-12: RS 2 and RS 3 Redesign at 2,000 GJ

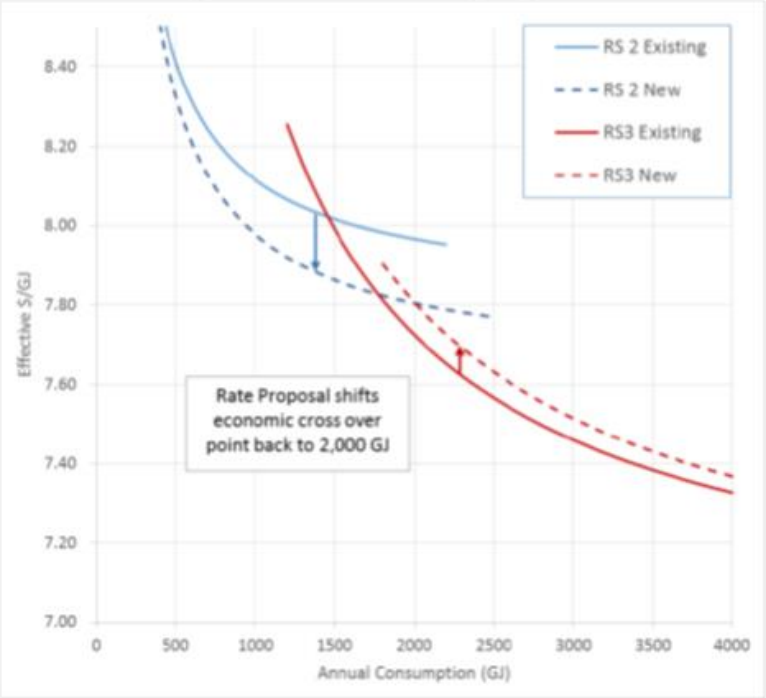
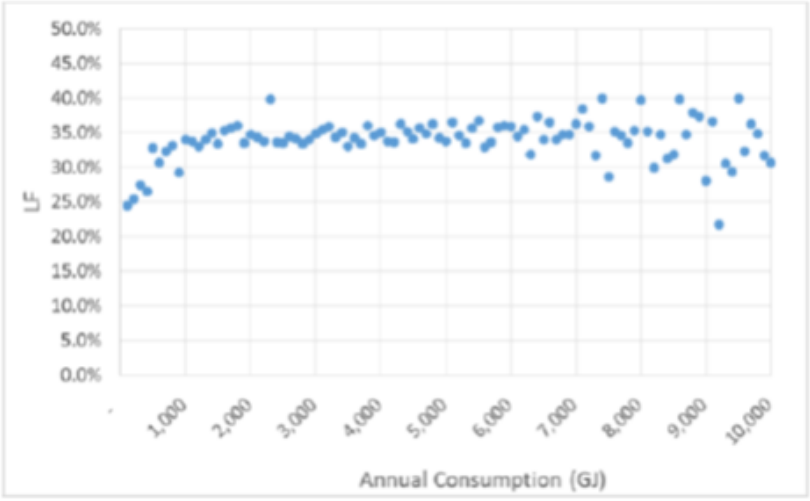


Figure 8-10: Average Commercial Customer Load Factor versus Annual Consumption Levels



35.1 FEI's three options include realigning the segmentation threshold to either 1,000 GJ, or 1,400 GJ, or to adjust the basic charge and delivery charge to support the existing crossover at 2,000 GJ, while achieving economic neutrality. Would it be possible to adjust the basic charge and the delivery charge to align with an economic crossover at about 1,000 GJ and still achieve economic neutrality? Please explain why or why not.

Response:

It would be possible to adjust the basic and volumetric charges to result in an economic crossover at an annual consumption of 1,000 GJ. The steps required to do this would include a review of the approximately 87,000 customers to determine which particular customers would move to RS 3 (those consuming > 1,000 GJ), migration of those customers volumes and load factors to RS 3, recalculation of the load factors for both RS 2 and RS 3, recalculating the customer weighting factors for service lines and meters for RS 2 and RS 3, reallocating costs in the COSA based on the customer migration results, re-running rate optimization to ensure bill impacts are reasonable and do not cause rate shock, resetting the revenues in the COSA based on the newly developed rates and, finally, testing R:C ratios for reasonableness. If R:C ratios fall outside the range of reasonableness, rebalancing and rate optimization would need to be run again.

Apart from the analysis and redesign required from a rate design perspective, at or near the 2,000 GJ per year consumption level there are currently about 350 customers. Because these customers are near the small (RS 2) and large (RS 3) commercial customer threshold, their consumption is reviewed annually to determine if they should be switched from RS 2 to RS 3 or vice versa. There are about 1,600 customers at or near 1,000 GJ per year consumption level so the annual customer review effort would quadruple and more customers may experience rate instability if they had to be moved from RS 2 to RS 3 or vice versa.

35.1.1 If yes, please provide details of the changes that would be required in order to do, and the impacts that might be expected from such changes.

Response:

Please refer to the response to CEC-FEI IR 1.35.1.

35.1.2 If no, please explain briefly why not.

Response:

Please refer to the response to CEC-FEI IR 1.35.1.

35.2 Has FEI considered the extent of the dispersion of load factors above 7000 GJ/year consumption, and would it make rate design sense to treat the customers in this group differently based on load factor? Please explain.

Response:

FEI has considered the extent of dispersion of load factors above 7,000 GJ/year consumption and concluded that there is no reason from a rate design perspective to consider a threshold level of 7,000 GJ/year as a basis for a consumption threshold within the commercial customer segment. While Figure 8-10 shows a greater dispersion of load factors above 7,000 GJ annual consumption, there is not a discernible trend that load factors are either higher or lower than for consumption levels below 7,000 GJ per year. As mentioned in Section 8.3.2.2 of the Application, while differences can be found at other threshold levels as well as 2,000 GJ, the results would need to be significantly different to provide a compelling argument to move away from the existing threshold of 2,000 GJ or to establish another consumption threshold for higher volume commercial customers. Larger volume commercial customers have RS 5 and RS 25 as alternative rate schedules to take service under.

36. Reference: Exhibit B-1, page 9-9

> The change in method to calculate the Daily Demand requires the Demand Charge to be reset to continue to send the appropriate price signals so that only customers with greater than 40% load factor have an incentive to take service under RS 5/RS 25. Customers with a load factor less than 40% should be taking service under FEI's Large Commercial rate schedules. FEI's proposed solution is to increase the Demand Charge by $3.00 which will send the appropriate price signals to customers.

36.1 On what basis has FEI established a 40% load factor as the appropriate threshold for customers to take service under RS 5/RS 25? Please provide the rationale and the evidence to support it.

Response:

FEI has not established a threshold for customers to take service under RS 5/25. However, as described in Section 9.5.2 of the Application, General Firm Service is intended for customers that generally use natural gas in a process – a load that is relatively non-temperature sensitive with an average load factor of 40 percent or more.

In 2001, the load factor for Large Commercial Service customers was 33 percent and for General Firm Sales Service (RS 5) was 45 percent; in 2016, the respective load factors were 37 percent and 45 percent. The midpoint between these average load factors is approximately 40 percent for both 2001 and 2016.

37. Reference: Exhibit B-1, page 9-20

Table 9-4: 2016 COSA Rates for RS 5 and RS 25

	RS 5	RS 25
Basic Charge $ / Month	$587.00	$587.00
Demand Charge $ / Month / GJ of Daily Demand	$21.596	$21.596
Delivery Charge $ / GJ	$0.887	$0.887
Administrative Charge $ / Month	N / A	$78.00

37.1 What costs are recovered in the Administrative charge for RS 25?

Response:

Prior to this Application, the last time the Administration Charge per month was reviewed was in 2003 as part of the 2003 Revenue Requirements Application (2003 RRA). FEI proposed a reduction in the Administration Charge per month for Rate Schedules 22, 22A, 22B, 23, 25 and 27 from $87 to $70. Please refer to Attachment 37.1 which outlines the response to the 2003 RRA BCUC IR 2.19.3, and the total annual transportation services administration costs recovered through the Administration Charge per month at that time.

Attachment 37.1 contains page 47 of the Commission Order and Decision G-7-03 from the 2003 Revenue Requirements Application, Section 7.5.2, which approved the current cost recovery methodology and an Administration Charge per month of $70 effective March 1, 2003, for FEI Rate Schedules 22, 22A, 22B, 23, 25 and 27.

Finally, please refer to Appendix 11-4 of the Application Supplemental Filing (Ex. B-1-1) which outlines the basis for the calculation for the proposed Administration Charge per Month of $39.

38. Reference: Exhibit B-1, page 9-12

Table 9-5: Example of Demand Charge Calculation[147]

Line		Customer A	Customer B
1	Annual Consumption GJ	50,000	50,000
2	Load Factor	45%	55%
3	Peak Day Demand GJ = (Line 1 / 365) / Line 2	304	249
4	Demand Charge $ / GJ / Month	$21.596	$21.596
5	Annual Demand Charge = Line 3 x Line 4 x 12	$78,782	$64,529
6	Average Demand Charge Cost per GJ Delivered (Line 5 / Line 1)	$1.576	$1.291

As can be seen in the example above, the higher load factor customer will have a lower average cost because the Demand Charge is applied to a lower peak day demand (i.e., the Daily Demand as defined in the rate schedules). Using a Demand Charge is therefore a method of charging a lower average cost to efficient users of FEI's system with high load factors. This cannot be achieved by using a volumetric charge alone.

Since the utility's delivery costs are almost fully fixed, using a fixed Demand Charge and a fixed Basic Charge is more efficient for cost recovery of the allocated costs to serve industrial loads. FEI concludes that the existing rate structure for RS 5 and 25 is working well as intended. However, to use a demand charge it is necessary to have a means to determine what the peak day demand value is, which is discussed in Section 9.5.3.4.

38.1 Please confirm that the higher load factor customer contributes a smaller amount to peak demand, and therefore places lower costs on the system overall relative to consumption level.

Response:

Confirmed in respect of demand-related costs. The higher load factor customer in the example in Table 9-5 of the Application contributes a smaller amount to peak demand, and therefore places lower demand-related costs on the system overall at a given annual consumption level; this is not true of the other cost classifications, i.e., customer-related or energy-related costs

39. Reference: Exhibit B-1, page 9-12

> ***9.5.3.3 Multi-Jurisdiction Review of Rates***
>
> As discussed above in Section 9.4, FEI reviewed firm industrial rates offered by natural gas utilities in other jurisdictions. Based on this review, a demand charge with a volumetric delivery charge rate design is used by 6 out of 10 Canadian utilities as shown in Table 9-3. That is, six of the ten utilities surveyed used some form of demand charge. Also, three utilities required a minimum load factor to qualify for the rate.
>
> The survey shows that FEI's rate structure for RS 5 and RS 25 is not unique in having a demand charge and a volumetric delivery charge to recover the costs to serve General Firm Service customers. This review supports FEI's continued use of a demand / volumetric delivery rate design for the firm general service rate schedule.

39.1 Did FEI consider a minimum load factor to qualify for this rate?

Response:

FEI did not consider a minimum load factor to be necessary. The rates for RS 5 and RS 25 as proposed send the proper price signals for this service so that a minimum load factor is not needed. Customers can assess based on their expected total demand and load profile whether it makes economic sense to receive service under RS 5/25 or under some other rate schedule. Please also refer to the responses to BCUC-FEI IRs 1.30.2, 1.30.3 and 1.30.4.

39.1.1 If not, please explain why not.

Response:

Please refer to the response to CEC-FEI IR 1.39.1.

39.1.2 If yes, what options did FEI consider with regard to this possibility, and what were the outcomes? Please explain.

Response:

Please refer to the response to CEC-FEI IR 1.39.1.

40. Reference: Exhibit B-1, page 9-13 and 9-14 and page 9-15

> In short, a customer's peak day demand is derived based upon grossing up the customer's highest daily average usage from monthly billing data by a factor of 1.25 to estimate their peak day consumption within their peak month usage[148].

Today, all RS 5/RS 25 customers have metering in place that can provide daily consumption figures. With daily measurement information available for all RS 5/RS 25 customers, FEI reviewed the current demand formula multiplier of 1.25 to determine whether or not it is reflective of this customer group's peak day consumption and, if not, whether the multiplier should be adjusted or alternatively whether a new method should be developed and implemented.

The current method of determining the Daily Demand overestimates the peak day demand for the majority of RS 5/RS 25 customers. This can be seen by comparing the average Daily Demand using the current method to the results for the average consumption on the 3 or 5 coldest days. As shown in the table below, for approximately 450 of the 774 customers (those with a load factor >50%), the current method using a 1.25 multiplier yields an average Daily Demand that is 46% higher than the actual average consumption on the five coldest days (105 GJ / 72 GJ – 1). When considering all customers, the average Daily Demand is 30% higher than the average demand per day derived from actual consumption on the three or five coldest days (100 GJ / 77 GJ – 1).

Table 9-6: Average Daily Demand (GJ) per Customer by Load Factor Segment (Combined Totals for RS 5 and RS 25 Customers)

		Current Formula for Daily Demand		Average Consumption on Coldest			
				3 Days		*5 Days*	
		Average Daily Demand	# of Customers	Average Daily Demand	# of Customers	Average Daily Demand	# of Customers
2	<40% Load Factor	174	55	150	44	159	33
3	40% to <45% Load Factor	93	75	97	54	109	43
4	45% to <50% Load Factor	73	196	77	93	72	87
5	>50% Load Factor	105	447	71	576	72	607
6	All Customers	100	774	77	774	77	774

FEI considered the following options for estimating peak day demand:

1. Status Quo/Current Formula – Continue to use the current Daily Demand formula with the 1.25 multiplier.
2. Current Formula with Updated Multiplier – Use the Current Formula method described above, but update the current 1.25 multiplier to align with the customer groups' coincident daily usage under peak weather conditions (5 coldest days for their region) for each customer.149
3. FEI System Maximum Day Send Out – Use the customer's actual consumption that occurred on the same day as FEI's maximum daily send out (i.e., during 2015 the maximum daily send out occurred on December 31, 2015).
4. Average Consumption on 3 or 5 Coldest Days in Region – Use the customer's actual average daily consumption over the 5 coldest days for their region.
5. Modified Formula – Use the greater of the customer's average consumption on the five coldest days for their region or one half of the average summer maximum day (as in the current formula method).

40.1 Would FEI agree that using customers' actual data represents a more accurate method of calculating load factor than grossing up highest daily averages? Please explain.

Response:

Each of the Methods 2 through 5 use customers' actual data. For purposes of calculating load factor, FEI would generally agree that it is better to use customers' actual load data.

Load factor is a derived value of average day use divided by a value for the peak. For RS 5/25 customers, it is not the load factor that is important. Rather, it is the derivation of Daily Demand to be multiplied by the Demand Charge that is important for deriving the revenues from General Firm Service customers to cover the costs to serve those customers. On that basis, when looking at the results on Tables 9-9 and 9-8, the two methods that result in the least number of customers with a zero Daily Demand are Method 2 - Current Formula with Updated Multiplier or Method 5 - Modified Formula.

40.2 Please provide the anticipated outcomes for customers under each of the alternatives, including anticipated bill changes, and % bill changes and the number of customers affected in each of the load factor categories.

Response:

In the tables below, the bill impact is the change in the annual bill compared to what the bill would be using the current 1.25 multiplier applied to the COSA Demand Charge of $21.596 / month / GJ of Daily Demand. For each of the methods shown below, the bill impacts include the reduction in the monthly Administration charge applicable to RS 25 customers. The cost of gas has not been included in the annual bill, so the percentage bill impact change is related to the proposed increase in the Demand Charge and the reduced Administration fee. For each of the methods, the annual bill impact also includes the change in the determination of the Daily Demand. As can be seen from the tables below, FEI's proposed alternative has the least annual bill impact.

Change to Updated Multiplier of 1.10

Updated Multiplier	# of Customers	Current Method @ COSA Rates Annual Bill	Updated Multiplier @ Proposed Rate Annual Bill	Change in Bill	Percentage Change
Customers with Zero Demand	1	$ 7,980	$ 7,512	$ (468)	-5.9%
< 40% Load Factor	26	$ 1,655,598	$ 1,650,664	$ (4,934)	-0.3%
40% - 45% Load Factor	22	$ 1,779,201	$ 1,773,697	$ (5,504)	-0.3%
45% - 50% Load Factor	65	$ 3,049,262	$ 3,031,960	$ (17,302)	-0.6%
> 50% Load Factor	660	$ 32,950,454	$ 32,773,534	$ (176,920)	-0.5%
Total	**774**	**$ 39,442,496**	**$ 39,237,367**	**$ (205,129)**	**-0.5%**

Change to Demand on FEI Maximum Day Send Out

FEI Maximum Day Send Out	# of Customers	Current Method @ COSA Rates Annual Bill	FEI Max Day Send Out @ Proposed Rate Annual Bill	Change in Bill	Percentage Change
Customers with Zero Demand	13	$ 474,161	$ 252,851	$ (221,310)	-46.7%
< 40% Load Factor	55	$ 3,421,947	$ 3,885,078	$ 463,131	13.5%
40% - 45% Load Factor	64	$ 2,733,100	$ 2,937,141	$ 204,041	7.5%
45% - 50% Load Factor	104	$ 4,409,868	$ 4,585,542	$ 175,674	4.0%
> 50% Load Factor	538	$ 28,403,420	$ 26,148,193	$ (2,255,227)	-7.9%
Total	**774**	**$ 39,442,496**	**$ 37,808,805**	**$ (1,633,691)**	**-4.1%**

Change to Average Consumption on Coldest 3 Days

Average Consumption on Coldest 3 Days	# of Customers	Current Method @ COSA Rates Annual Bill	Ave Consumption on Coldest 3 Days @ Proposed Rate Annual Bill	Change in Bill	Percentage Change
Customers with Zero Demand	7	$ 182,052	$ 106,621	$ (75,430)	-41.4%
< 40% Load Factor	44	$ 2,838,477	$ 2,949,613	$ 111,136	3.9%
40% - 45% Load Factor	54	$ 2,504,826	$ 2,657,705	$ 152,879	6.1%
45% - 50% Load Factor	93	$ 3,761,270	$ 3,880,329	$ 119,059	3.2%
> 50% Load Factor	576	$ 30,155,871	$ 27,118,475	$ (3,037,396)	-10.1%
Total	**774**	**$ 39,442,496**	**$ 36,712,743**	**$ (2,729,753)**	**-6.9%**

Change to Average Consumption on Coldest 5 Days

Average Consumption on Coldest 5 Days	# of Customers	Current Method @ COSA Rates Annual Bill	Ave Consumption on Coldest 5 Days @ Proposed Rate Annual Bill	Change in Bill	Percentage Change
Customers with Zero Demand	4	$ 81,120	$ 50,862	$ (30,258)	-37.3%
< 40% Load Factor	33	$ 2,303,742	$ 2,344,943	$ 41,201	1.8%
40% - 45% Load Factor	43	$ 2,344,713	$ 2,361,057	$ 16,344	0.7%
45% - 50% Load Factor	87	$ 3,371,433	$ 3,476,441	$ 105,009	3.1%
> 50% Load Factor	607	$ 31,341,487	$ 28,496,380	$ (2,845,108)	-9.1%
Total	**774**	**$ 39,442,496**	**$ 36,729,683**	**$ (2,712,812)**	**-6.9%**

Change to Modified Formula

Modified Formula	# of Customers	Current Method @ COSA Rates Annual Bill	Modified Formula @ Proposed Rate Annual Bill	Change in Bill	Percentage Change
Customers with Zero Demand	1	$ 7,980	$ 7,512	$ (468)	-5.9%
< 40% Load Factor	35	$ 2,338,749	$ 2,381,575	$ 42,826	1.8%
40% - 45% Load Factor	43	$ 2,344,713	$ 2,361,057	$ 16,344	0.7%
45% - 50% Load Factor	87	$ 3,371,433	$ 3,476,441	$ 105,009	3.1%
> 50% Load Factor	608	$ 31,379,621	$ 28,998,679	$ (2,380,942)	-7.6%
Total	**774**	**$ 39,442,496**	**$ 37,225,265**	**$ (2,217,231)**	**-5.6%**

41. Reference: Exhibit B-1, page 9-18 and 9-19

Table 9-10: Summary of Methods to Determine Daily Demand

Methods	Pros	Cons
Status Quo / Current Formula • 1.25 x times the greater of highest monthly average day use from November 1 to March 31 or ½ of highest monthly average day use from April 1 to October 31	• Formula has been in use for many years and is well understood by customers • Rate calculation is understood and the information is readily available to customers	• 1.25 multiplier is not aligned with coincident peak usage • Multiplier is derived from the whole of all customers & may not reasonably calculate an individual customer's peak day
FEI System Maximum Day Send Out • Customers' consumption on FEI's maximum day send out	• Measures a customer's demand during FEI system max day	• Customer's Daily Demand on single day maximum send out is variable potentially producing erratic results from year to year • Unstable revenues from unstable Daily Demand • A formula will still be required for new customers for which there was no consumption record on system maximum day
Average Consumption on 5 Coldest Days in Region	• Average of multiple days reduces the impact of an anomalous day of low consumption which would not be representative of demand during regular business operations during cold weather days	• Requires additional detail related to weather station daily temperatures by region where customers are located • Anomalous result could still occur for customers who may have had consecutive days of reduced demand due to plant outages or reduced demand for holiday season • A formula will still be required for new customers where there is no consumption record during the 5 coldest days
Modified Formula • The greater of the average consumption on the 5 coldest days or ½ of highest monthly average day use from April 1 to October 31	• Removes factoring in of anomalous days of zero or very low demand in the winter period due to holiday season business operations • Provides Daily Demand measurement for customers whose peak occurs in the summer period (56 customers in 2015)	• Requires additional detailed information by weather station in regions where customers are located • Details might not be readily available to customers • Will need formula for new customers where there is no consumption record during the 5 coldest days
Current Formula with Adjusted Multiplier • (same as current method) except use lower multiplier that more closely aligns with peak demand as measured by average consumption on 5 coldest days)	• Formula has been in use for many years and is well understood by customers • Rate calculation is understood and information is readily available to customers • Updated multiplier aligns the Daily Demand to the peak demand of all General Firm customers during the 5 coldest days, i.e., the sum of all customers demand in their region	• Multiplier is based on all General Firm customers demand & not based on individual customer's peak consumption

41.1 Please confirm that using actual customer data, the load factor could be adjusted annually.

Response:

Confirmed.

42. Reference: Exhibit B-1, page 9-17 and page 9-20

Table 9-8: Number of Customers by Load Factor Segment (Combined Totals for RS 5 and RS 25 Customers)

		Method 1	Method 2	Method 3	Method 4		Method 5
1		Current Formula for Daily Demand	Current Formula Updated Multiplier	FEI System Maximum Day Send Out	Average Consumption on Coldest 3 Days	Average Consumption on Coldest 5 Days	Modified Formula with 5 Day Average
2	Customers with Zero Demand	1	1	13	7	4	1
3	<40% Load Factor	55	26	55	44	33	35
4	40% to <45% Load Factor	75	22	64	54	43	43
5	45% to <50% Load Factor	196	65	104	93	87	87
6	>50% Load Factor	447	660	538	576	607	608
7	**Total**	**774**	**774**	**774**	**774**	**774**	**774**

This option strikes a balance between better alignment of an estimated coincident peak demand and a high level of customer understanding of how the rates would be applied. This option will also provide for more rate and revenue stability producing fewer anomalous results.

Other than the adjustment to the multiplier, this method uses the current formula, which has been used for many years and is understood by customers. The rate calculation is understandable and it is easy to implement. This method also reduces potential anomalous results that could understate or not be representative of a customer's peak demand. Anomalous results could be substantive from reduced demand on Sundays, statutory holidays or short term seasonal holidays, such as the Christmas / New Year period when some customers would have reduced operations. By maintaining the formula and not requiring daily consumption figures for every customer, new customers to this rate class that do not yet have daily metering can still determine if there is a benefit of moving into the rate class.

For all of these reasons, FEI proposes to update the multiplier in the Daily Demand formula to 1.10 as discussed above.

42.1 Please elaborate on the issue of potential anomalous results and how they might impact (a) the customer, (b) other customers within the rate class, and (c) customers in other rate classes.

Response:

Anomalous results are discussed below in the context of the method to determine Daily Demand.

Anomalous results are those cases where a method for determining Daily Demand derives a very low non-representative value that does not match the customer's general demand on cold weather days.

An anomalous outcome could result in a customer not having to pay a fair and reasonable demand charge in the subsequent year, which allows the customer to receive firm service at a significantly reduced cost. This would mean the cost of providing the capacity and firm service to this customer would not be properly recovered through the demand charge. It would also mean that the rates would be higher for all other non-bypass customers so that the total revenues would equal the total cost of service on a forecast basis.

FEI considers this to be an issue of fairness. The method to determine Daily Demand should minimize such anomalous results so that all customers are contributing appropriately to the recovery of costs to provide capacity for firm service.

42.2 Does FEI consider its industrial customers to be sophisticated consumers of energy? Please explain why or why not.

Response:

Based upon the preamble FEI assumes that by industrial customers the question is referring to customers within RS 5 and RS 25. FEI's customers within these rate classes cover a broad range of sectors and end-uses, from multifamily/commercial office space to small industrial manufacturing type facilities. Given the diversity, there will be varying degrees of energy awareness and sophistication among these customers.

43. Reference: Exhibit B-1, page 9-21

> FEI considered the following options to ensure there is an appropriate economic incentive for lower load factor customers to continue to take service under RS 3/RS 23 rather than RS 5/RS 25.
>
> 1. Change the Basic Charge – raising the Basic Charge will mostly incent low volume customers to take service under Large Commercial RS 3/RS 23, but would not target customers with a low load factor. This is because the Basic Charge is a fixed monthly charge independent of the monthly or annual demand or the load factor of the customer.
> 2. Change the Delivery Charge – raising the Delivery Charge will affect all customers based on their total demand without regard to the customer's load factor. This will encourage more customers with a high load factor to migrate to Large Commercial which is not the intent of the change that is required.
> 3. Remove the Demand Charge - removing the demand charge from RS 5/RS 25 (as suggested by a stakeholder during the stakeholder engagement workshop) would remove the mechanism that rewards more efficient system utilization by higher load factor customers. RS 5 and RS 25 were designed to serve high load factor customers.
> 4. Change the Demand Charge – raising the Demand Charge will more directly incent low load factor customers to take service under Large Commercial RS 3/RS 23.
>
> Of the options listed above, the best mechanism to provide an incentive for customers whose load factor is less than 40% to take service under RS 3/RS 23, rather than RS 5/RS 25, is to increase the Demand Charge.
>
> Specifically, FEI proposes to raise the Demand Charge by $3.00 per month per GJ of Daily Demand to increase the economic crossover point between RS 3/RS 23 and 5/25.

43.1 Could FEI simply introduce a restriction for a minimum load factor going forward and grandfather existing customers? Please explain why or why not.

Response:

Please refer to the responses to BCUC-FEI IRs 1.30.2 to 1.30.4. If a minimum load factor was to be introduced, FEI would not seek to grandfather existing customers as the minimum load factor should apply to all customers taking service under RS 5/25.

43.1.1 If yes, would a 40% load factor be the appropriate cut-off? Please explain why or why not and provide FEI's view of the appropriate cut-off.

Response:

Please refer to the responses to BCUC-FEI IRs 1.30.2 to 1.30.4.

44. Reference: Exhibit B-1, page 9-22 and 9-23 and page 9-24

Specifically, FEI proposes to raise the Demand Charge by $3.00 per month per GJ of Daily Demand to increase the economic crossover point between RS 3/RS 23 and 5/25.

The economic cross over point after increasing the Demand charge by $3.00 is shown in Table 9-13 below. As shown in the table, the proposed increase to the Demand charge increases the economic cross over point such that there would be relatively few customers that would have sufficient annual volumes to make taking service under RS 5/RS 25 economic at a load factor less than 40%. Table 9-14 below shows the economic crossover from Table 9-13 and Table 9-7, with the proposed rates for RS 3/RS 23 and RS 5/RS 25 which shows the increased annual volume required for a commercial customer to be incented to take service under RS 5/RS 25.

Table 9-13: Large Commercial / General Firm Economic Crossover at Varying Load Factors at Proposed Rates

		RS 23		RS 25		
Monthly Charges (Basic + Admin. Fee) $/Month		$223.78		$665.00	From Table 9-7 at 2016 COSA RATES	
Demand Charge $/GJ/Month		N / A		$24.596		
Delivery Charge $/GJ		$3.175		$0.887		
		Economic Cross-over (GJ/Year)	**Daily Demand**	**Peak Winter Month With 1.1 multiplier**	**Daily Demand**	**Peak Winter Month With 1.25 multiplier**
	50%	7,894 GJ	43 GJ	1,180 GJ	35 GJ	840 GJ
	45%	10,783 GJ	66 GJ	1,790 GJ	48 GJ	1,145 GJ
Load Factor	40%	19,874 GJ	136 GJ	3,712 GJ	75 GJ	1,797 GJ
	39%	24,675 GJ	173 GJ	4,727 GJ	84 GJ	2,028 GJ
	38%	33,089 GJ	239 GJ	6,506 GJ	97 GJ	2,327 GJ
	37%	51,656 GJ	382 GJ	10,432 GJ	114 GJ	2,730 GJ
	36%	126,696 GJ	964 GJ	26,296 GJ	138 GJ	3,301 GJ

Table 9-14: Economic Crossover Volume at Proposed Rates (Table 9-13) Compared to at 2016 COSA Rates (Table 9-7)

Load Factor	Economic Crossover at Proposed Rates	Economic Crossover at 2016 COSA Rates
50%	7,894 GJ	6,386 GJ
45%	10,783 GJ	7,834 GJ
40%	19,874 GJ	10,930 GJ
39%	24,675 GJ	12,027 GJ
38%	33,089 GJ	13,447 GJ
37%	51,656 GJ	15,360 GJ
36%	126,696 GJ	18,073 GJ

The tables above demonstrate that the proposed rate changes improve the incentive for customers who are less than 40% load factor to appropriately take service under RS 3/RS 23 because of the increased volume it takes to reach the point of indifference when the annual bill would be the same under large commercial service or general firm service.

9.5.9 Bill Impact Analysis

The bill impact from the reduction in the multiplier in the Daily Demand formula is offset by the $3 increase in the Demand Charge. The net impact on RS 5/RS 25 revenues is an incremental $45 thousand of revenue, which is approximately a $0.003 per GJ increase or $5 per customer per month.

44.1 The economic crossover is increased for all load factor and remains almost double for customers with load factors of 40%. Please comment on FEI's expectation of the impact of the higher crossover for customers with load factors of 40%, 45% and 50%.

Response:

Considering the combined effect of lowering the Daily Demand and increasing the Demand Charge by $3/Month/GJ of Daily Demand, FEI does not anticipate any additional migration of customers either into RS 5/25 or out of RS 5/25 than would already be incented to move either way based on the current multiplier of 1.25 and 2016 COSA Rates - Demand Charge. Overall, the net bill impact of these changes as shown in Exhibit B-1, Table 12-2, Page 12-5, is an additional $45.2 thousand which is offset by revenue shifts to RS 1.

With regard to customers who are in the 40 percent to 50 percent load factor range and whose annual volume is less than 8,000 GJ per year, these customers should consider switching to Large Commercial Service, which is the case even at the 2016 COSA Rates. FEI does periodic reviews and, as warranted, will advise customers of their options and that they may want to consider switching to other rates that may result in lower annual bills.

44.2 Please provide Tables 9-13 and 9-14 demonstrating the economic crossovers of increasing the demand charge by $2 instead of $3.

Response:

Please refer to the response to BCUC-FEI IR 1.31.2 regarding corrected versions of Tables 9-13 and 9-14. The tables provided below are based on the corrected tables provided in response to BCUC-FEI IR 1.31.2, but with a Demand Charge increase of only $2 per month per GJ of Daily Demand. At a Load Factor of 30 percent, there is no crossover as the mathematical result is a negative volume.

Corrected Table 9-13: Large Commercial / General Firm Economic Crossover at Varying Load Factors with $2 Demand Charge Increase

		RS 23		RS 25		
Monthly Charges (Basic + Admin. Fee) $/Month		$184.78		$626.00	From Table 9-7 at 2016 COSA RATES	
Demand Charge $/GJ/Month		N / A		$23.596		
Delivery Charge $/GJ		$3.190		$0.887		
		Economic Cross-over (GJ/Year)	**Daily Demand**	**Peak Winter Month With 1.1 multiplier**	**Daily Demand**	**Peak Winter Month With 1.25 multiplier**
	50%	7,046 GJ	39 GJ	1,053 GJ	34 GJ	814 GJ
	45%	9,143 GJ	56 GJ	1,518 GJ	46 GJ	1,102 GJ
Load Factor	40%	14,562 GJ	100 GJ	2,720 GJ	71 GJ	1,704 GJ
	39%	16,869 GJ	119 GJ	3,232 GJ	80 GJ	1,914 GJ
	38%	20,245 GJ	146 GJ	3,981 GJ	91 GJ	2,182 GJ
	37%	25,658 GJ	190 GJ	5,182 GJ	106 GJ	2,537 GJ
	36%	35,747 GJ	272 GJ	7,419 GJ	126 GJ	3,030 GJ
	35%	61,177 GJ	479 GJ	13,060 GJ	157 GJ	3,761 GJ
	30%	(18,718) GJ	(171) GJ	(4,662) GJ	(758) GJ	(18,198) GJ

Corrected Table 9-14: Economic Crossover Volume with $2 Demand Charge Increase (Table Above) Compared to at 2016 COSA Rates (Corrected Table 9-7)

Load Factor	Economic Crossover at $2 Demand Charge Increase	Economic Crossover at 2016 COSA Rates
50%	7,046 GJ	6,191 GJ
45%	9,143 GJ	7,541 GJ
40%	14,562 GJ	10,369 GJ
39%	16,869 GJ	11,351 GJ
38%	20,245 GJ	12,608 GJ
37%	25,658 GJ	14,274 GJ
36%	35,747 GJ	16,589 GJ
35%	61,177 GJ	20,020 GJ
30%	(18,718) GJ	(83,029) GJ

44.2.1 Please provide a discussion of the bill impact of such a change.

Response:

Changing the Demand Charge increase to $2 would erode the stability of the overall Rate Design and adversely impact residential customers.

Reducing the increase to the Demand Charge from $3 per month per GJ of Daily Demand to $2 would result in a shift from a surplus of $45.2 thousand to a deficit of $776.1 thousand that must be made up by residential customers. Reducing the increase to the Demand Charge also lowers the load factor that would economically enable customers to move from Large Commercial service to General Firm Service. With FEI's proposed rates, customers consuming 15,000 GJ to 20,000 GJ would need a load factor of approximately 40 percent to 41 percent to be just as well off under RS 25 as under RS 23. However, with the increase in the Demand Charge reduced from $3 to $2, the load factor decreases to 38 percent to 40 percent for a customer to be just as well off under RS 25. From the 2015 Bill Frequency Analysis, there were 50 Large Commercial customers that consume more than 15,000 GJ and approximately 25 customers whose consumption exceeds 20,000 GJ. Changing the Demand Charge increase to $2 could therefore lead to customer migration between rate schedules. If enough customers migrate, costs would need to be reallocated in the COSA model, possibly requiring rate resetting for RS 5/25 and then RS 3/23 and RS 2 to maintain a 2,000 GJ economic crossover.

44.3 Please provide Table 9-13 and 9-14 demonstrating the economic crossovers of increasing the demand charge by $1 instead of $3.

Response:

Refer to the response to BCUC-FEI IR 1.31.2 regarding corrected versions of Tables 9-13 and 9-14.

The tables provided below are based on the corrected tables from BCUC-FEI IR 1.31.2, but with a Demand Charge increase of only $1 per month per GJ of Daily Demand. At a Load Factor of 30 percent, there is no crossover as the mathematical result is a negative volume.

Corrected Table 9-13: Large Commercial / General Firm Economic Crossover at Varying Load Factors with $1 Demand Charge Increase

		RS 23		RS 25		
Monthly Charges (Basic + Admin. Fee) $/Month		$184.78		$626.00	From Table 9-7 at 2016 COSA RATES	
Demand Charge $/GJ/Month		N / A		$22.596		
Delivery Charge $/GJ		$3.190		$0.887		
		Economic Cross-over (GJ/Year)	**Daily Demand**	**Peak Winter Month With 1.1 multiplier**	**Daily Demand**	**Peak Winter Month With 1.25 multiplier**
	50%	6,479 GJ	35 GJ	968 GJ	34 GJ	814 GJ
	45%	8,119 GJ	49 GJ	1,348 GJ	46 GJ	1,102 GJ
Load Factor	40%	11,877 GJ	81 GJ	2,219 GJ	71 GJ	1,704 GJ
	39%	13,297 GJ	93 GJ	2,548 GJ	80 GJ	1,914 GJ
	38%	15,212 GJ	110 GJ	2,991 GJ	91 GJ	2,182 GJ
	37%	17,935 GJ	133 GJ	3,622 GJ	106 GJ	2,537 GJ
	36%	22,113 GJ	168 GJ	4,590 GJ	126 GJ	3,030 GJ
	35%	29,337 GJ	230 GJ	6,263 GJ	157 GJ	3,761 GJ
	30%	(30,556) GJ	(279) GJ	(7,611) GJ	(758) GJ	(18,198) GJ

Corrected Table 9-14: Economic Crossover Volume with $1 Demand Charge Increase (Table Above) Compared to at 2016 COSA Rates (Corrected Table 9-7)

Load Factor	Economic Crossover at $1 Demand Charge Increase	Economic Crossover at 2016 COSA Rates
50%	6,479 GJ	6,191 GJ
45%	8,119 GJ	7,541 GJ
40%	11,877 GJ	10,369 GJ
39%	13,297 GJ	11,351 GJ
38%	15,212 GJ	12,608 GJ
37%	17,935 GJ	14,274 GJ
36%	22,113 GJ	16,589 GJ
35%	29,337 GJ	20,020 GJ
30%	(30,556) GJ	(83,029) GJ

44.3.1 Please provide a discussion of the bill impact of such a change.

Response:

Changing the Demand Charge increase to $3 to $1 would erode the stability of the overall rate design and adversely impact residential customers.

Increasing the Demand Charge by only $1 per month per GJ of Daily Demand would result in a shift from an RS 5/25 surplus of $45.2 thousand to a deficit of $1.6 million that FEI anticipates would be made up by residential customers. In addition, lowering the Demand Charge increase also lowers the load factor at which it would be economically sensible for customers to move from Large Commercial Service to General Firm Service. With FEI's proposed rates, customers consuming 15,000 GJ to 20,000 GJ would need a load factor of approximately 41 percent to 40 percent to be just as well off under RS 25 as under RS 23. However, with only a $1 Demand Charge increase, the customer's required load factor decreases to 38 percent and 36 percent, respectively, to be just as well off under RS 25 as under RS 23. From the 2015 Bill Frequency Analysis, there were 50 Large Commercial customers that consume more than 15,000 GJ and approximately 25 customers whose consumption exceeds 20,000 GJ. These customers may therefore be incented to switch to RS 5/25, which would have cost and revenue allocation impacts, and would require the charges to be re-examined.

In summary, there are two important points to consider if the demand charge was increased only by $1 per month per GJ of Daily Demand, instead of $3.

1. Large Commercial customers who would be incented to migrate to General Firm Service, leading to a large revenue shift between RS 3/23 and RS 5/25 as well as a $1.6 million revenue shortfall from the existing General Firm Service customers to be recovered from Residential customers.

2. By lowering the change in the demand charge to an increase of $1 per month per GJ of Daily Demand coupled with the proposed change to a multiplier of 1.10, the load factor for economic switching from Large Commercial to General Firm declines to 38 percent to 36 percent which is the approximate average of Large Commercial customers in the COSA study.

45. Reference: Exhibit B-1, page 9-24 and 9-6

> FEI's interruptible rates are designed to provide sufficient incentive to encourage existing customers to remain on interruptible service and attract new interruptible customers. For interruptible customers, contributors to their cost of taking interruptible service are factors such as:
>
> - the customer's capital costs to install a backup energy system;
> - the cost of the alternate backup fuel;
> - the opportunity cost to the customer of potential lost production, should they need to curtail their operations; and
> - the potential frequency and level of service curtailment to the customer.
>
> During the 1996 Rate Design, FEI established a discount for interruptible service from General Firm Service (RS 5/RS 25) based upon an 80% load factor. In the 2001 Rate Design proceeding, this relationship was reviewed again in relation to the value of the discount from firm service. This discount was applied in comparison to the firm service rate offered to RS 5/RS 25 customers, with the discounting calculation again based on an 80% load factor.

45.1 Why did FEI establish 80% as the appropriate load factor for the RS5/RS 25 demand charge (plus delivery charge) on which to base the RS7/RS27 delivery charge.

Response:

Please refer to BCUC-FEI IR 1.32.7.1.

45.2 Please provide the evidentiary base for using an 80% load factor.

Response:

Please refer to BCUC-FEI IR 1.32.7.1.

46. Reference: Exhibit B-1, page 9-27

Table 9-16: RS 5 at 80% Load Factor Compared to RS 7[151]

Rate Schedule	Line No.		2001	2016 - Current	2016 – COSA
Effective Rate/GJ for an RS 5 firm service customer at an assumed **80% Load Factor**	1	*Demand Charge*	$0.509	$0.825	$0.888
	2	*Delivery Charge*	$0.502	$0.825	$0.887
	3	*Total*	$1.011	$1.650	$1.775
RS 7 *General Interruptible Sales Service*	4	*Delivery Charge*	$0.836	$1.353	$1.455
Differential (per GJ) *RS 5 – RS 7*	5		$0.175	$0.297	$0.320
Discount as a Percentage of Total Firm	6		17.3%	18.0%	18.0%

Notes:

- Line 1 is the RS 5/RS 25 Demand Charge converted to a volumetric rate based on an 80% Load Factor (detailed in the footnote)
- Line 2 is the RS 5/RS 25 Delivery Charge
- Line 3 is the sum of lines 1 and 2
- Line 4 is the RS 7/RS 27 Delivery Charge
- Line 5 is the value of the discount (Line 3 – Line 4) between RS 5/RS 25 and RS 7/RS 27
- Line 6 is the value of the discount expressed as a percentage of the total Firm (Line 3).

[151] 2016 – Current Demand Charge is equal to $20.077 x 12 / 365 / 80% = $0.825; 2016 COSA plus known and measurable changes Demand Charge = $21.596 x 12 / 365 / 80% = $0.888.

46.1 Please extend the table to include FEI's proposed increase to the demand charge in RS 5/25

Response:

Table 9-16 is reproduced below to include the last two columns which are taken from Table 9-20 of Exhibit B-1, Page 9-32.

Table 9-16: RS 5 at 80% Load Factor Compared to RS 7[5]

Rate Schedule	Line No.		2001	2016 - Current	2016 – COSA	2018 RS 7/27 Charges using 2001 Methodology	2018 Proposed with 90.9% Load Factor Adjustment
Effective Rate/GJ for an RS 5 firm service customer at an assumed 80% Load Factor	1	*Demand Charge*	$0.509	$0.825	$0.888	$1.011	$0.889
	2	*Delivery Charge*	$0.502	$0.825	$0.887	$0.887	$0.887
	3	*Total*	$1.011	$1.650	$1.775	$1.898	$1.776
RS 7 *General Interruptible Sales Service*	4	*Delivery Charge*	$0.836	$1.353	$1.455	$1.443	$1.443
Differential (per GJ) *RS 5 – RS 7*	5		$0.175	$0.297	$0.320	$0.455	$0.334
Discount as a Percentage of Total Firm	6		17.3%	18.0%	18.0%	24.0%	18.8%

Notes:

- Line 1 is the RS 5/RS 25 Demand Charge converted to a volumetric rate based on an 80% Load Factor (detailed in the footnote)
- Line 2 is the RS 5/RS 25 Delivery Charge
- Line 3 is the sum of lines 1 and 2
- Line 4 is the RS 7/RS 27 Delivery Charge
- Line 5 is the value of the discount (Line 3 – Line 4) between RS 5/RS 25 and RS 7/RS 27
- Line 6 is the value of the discount expressed as a percentage of the total Firm (Line 3).

[5] 2016 – Current Demand Charge is equal to $20.077 x 12 / 365 / 80% = $0.825; 2016 COSA plus known and measurable changes Demand Charge = $21.596 x 12 / 365 / 80% = $0.888.

47. Reference: Exhibit B-1, page 9-27, and page 9-29

As shown in Table 9-16 above, while the $/GJ value of the discount has increased from 2001 to 2016 COSA rates (due to general rate increases between 2001 and 2016), the relative percentage of the discount of the interruptible rate to the firm rate at an 80% load factor has remained relatively constant at about 18%.

Table 9-17: RS 5 at 55% Load Factor Compared to RS 7 at 80% Load Factor[152]

Rate Schedule	Line No.		2001	2016 - Current	2016 – COSA
Effective Rate/GJ for an RS 5 firm service customer at an assumed **55% Load Factor**	1	*Demand Charge*	$0.740	$1.200	$1.291
	2	*Delivery Charge*	$0.502	$0.825	$0.887
	3	*Total*	$1.242	$2.025	$2.178
RS 7 *General Interruptible Sales Service*	4	*Delivery Charge*	$0.836	$1.353	$1.455
Differential (per GJ) *RS 5 – RS 7*	5		$0.406	$0.672	$0.723
Discount as a Percentage of Total Firm	6		32.7%	33.2%	33.2%

Interruptible service should be offered at a suitable discount from firm service delivery rate in order to balance a number of the rate design principles, including:

- Principle 3: Price signals that encourage efficient use and discourage inefficient use
- Principle 4: Customer understanding and acceptance
- Principle 5: Practical and cost effective
- Principles 6 and 7: Rate and Revenue Stability

From the customer's perspective, the economic decision to take firm or interruptible service is dependent on whether the discount from firm is sufficient to compensate for the cost to have an alternate backup system and fuel that can be used or the cost from ceasing operations. Setting the discount either too high or too low would send the wrong price signals and could cause rate and revenue instability for customers and FEI, respectively. If the discount is too low, this may discourage new customers from considering interruptible service and may also cause existing interruptible customers to migrate to firm service. If the discount is too high and if the expected level of curtailment is very low, too many customers with firm service may elect to contract for interruptible service.

47.1 Please confirm that the appropriate discount rate should heavily consider the value to FEI, and to ratepayers of reducing peak demand.

Response:

Not confirmed. The interruptible discounts should be set at a level that maximizes the revenues from interruptible customers to offset as much as possible the largely-fixed utility cost of service otherwise borne by firm service customers. With that in mind, the appropriate discount from firm service should consider the incremental costs that interruptible customers may incur for alternate fuel, equipment costs and other costs as a result of being interrupted or the value of lost opportunities as a result of reduced production. As part of the 1996 Rate Design process the value of the discount was expressed as a Load Factor equivalent which was agreed to as part of the negotiated settlement and approved by the Commission. FEI takes into consideration the value of interruptible customers not being firm and of the avoided incremental cost of service, but this does not form the basis for estimating the amount of discount to offer Interruptible service versus Firm Service.

47.1.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC-FEI IR 1.47.1.

47.2 Would it be theoretically appropriate for FEI to encourage as many customers as required to move off the peak, in order to minimize peak demand and achieve high and consistent throughput throughout the year? Please explain why or why not.

Response:

No. While, as a general rule, having high load factor customers with a flat load promotes efficient use of the system, there are different considerations for new customers joining the system relative to existing customers changing their load profile.

New customers that have high load factors, or perhaps even use more gas in the summer than in the winter, will help to improve the overall load factor of the system.

For existing customers that move off peak there will be a reduction in revenues as the customer moves either from firm to interruptible service, or remains on firm service but takes measures to

reduce their demand charge. The costs of physical assets already in place to serve these customers and the costs for ongoing O&M and other expenses will continue to be incurred and form part of the utility's overall revenue requirement. Any loss of revenue from firm customers switching to interruptible service or reducing the firm demand would have to be recovered from all non-bypass customers, including commercial customers. In some cases a customer reducing its peak demand may free up capacity to serve other load growth, but whether this occurs is dependent on the specific circumstances, such as the load growth prospects in that particular part of the system.

For this reason, maintaining the existing discount for interruptible service is appropriate as it will not result in large shifts of customer from firm to interruptible, or vice versa.

47.3 Please explain if FEI considers 18% to be the optimal discount at 80% load factor and 33% to be the optimal discount at 55% load factor, and please explain why.

Response:

The existing discounts for interruptible service are appropriate and have been working well. As stated on page 9-29 of the Application: "FEI has experienced no unusual or unanticipated migration activity (from firm to interruptible or interruptible to firm) that would suggest the rates or rate structure are producing undesirable effects on customer's service option selections." As further demonstrated in Table 9-19 of the Application, the interruptible discounts are providing net benefits to FEI customers due to the system upgrade costs that are avoided by virtue of interruptible customers being off the system in peak winter conditions.

While FEI believes that the discounts are appropriate, FEI cannot confirm unequivocally that they are "optimal". There are a great variety of customers on either RS 5/25 firm service or RS 7/27 interruptible service. Each of these customers has a unique set of circumstances and an economic decision to make on what level of discount will lead them to pick either firm or interruptible service. The fact that customers, by and large, tend to remain in either the firm service or interruptible service categories suggests that the balance struck with the interruptible discounts is reasonable.

47.3.1 If these are not the optimal discounts, please provide FEI's view as to the optimal discount

Response:

Please refer to the response to BCUC-FEI IR 1.47.3.

48. Reference: Exhibit B-1, page 9-30

> The discount of approximately $0.34 per GJ is sufficient to require interruptible customers to have alternative backup fuel / systems to use when interruption is required by FEI. This is evidenced by the stability of customers taking interruptible service, i.e., the lack of migration in or out of RS 7/RS 27. Also, all non-bypass customers avoid an incremental $0.04 per GJ cost of service from avoided system improvements. The net benefit to non-bypass customers is approximately $5 million dollars.

Table 9-19: Net Savings to the Cost of Service

RS 7/27 Volumes (Table 9-2) PJ's	6.7
x Discount (Table 9-19)	$0.344
Dollar Value of Discount ($000s)	$2,305
All Non-Bypass Volumes (Appendix 9-3) TJ's	182,942
Avoided Incremental Cost of Service $/GJ	$0.040
Avoided Cost of Service ($000s)	$7,318
Net Savings to all Non-Bypass Customers ($000s)	$5,013

> FEI concludes that the existing rates for RS 7 and 27 achieve 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 customer to stay on interruptible service and to encourage new customers to sign up for interruptible service.

48.1 Please provide a graphic representation of, and the supporting data, the relationship between savings to non-bypass customers and increases in interruptible volumes.

Response:

If the increase in Interruptible volumes is from current firm service customers switching to interruptible service, there is no avoided incremental cost of service and no savings to non-bypass customers. Rather, the loss of revenue from the discount has to be made up from all non-bypass customers in FEI's next revenue requirements or annual review.

For new RS 7/27 customers that are in-fill customers on existing mains, the value of the avoided incremental cost of service would be site specific as to what costs would be incurred if the interruptible customer had taken firm service instead. As such, no general graphic representation of the relationship between savings to non-bypass customers and increases to interruptible volumes is possible.

48.2 Please provide an assessment of what might be required to incent additional interruptible volumes and whether or not discounts are sufficient.

Response:

Additional interruptible volumes would only provide net benefits to FEI's non-bypass customers if the interruptible volumes added represent new volumes of gas being consumed. If the incremental interruptible volumes come about by customer migration from firm service, non-bypass customers would experience a net loss from the additional interruptible load. Please refer also to the response to CEC-FEI IR 1.47.1.

49. Reference: Exhibit B-1, page 10-26

> Most days of the year, the System operates under normal conditions. Under normal conditions, customers within daily balanced groups are required to adhere to a 20% balancing tolerance. A balancing charge applies when a transportation customer under-delivers (meaning demand is greater than supply) beyond the 20% tolerance. The tolerance is applied based on a "greater of" formula. When authorized supply plus the greater of 120% or 100 GJ is insufficient to meet demand for a day, balancing charges will apply. Charges are $1.10/GJ in the winter and $0.30/GJ in the summer.

49.1 What was FEI's original rationale for allowing monthly balanced groups as well as daily balanced groups?

Response:

In the early 1990s, when the transportation model was being developed, the natural gas industry was transitioning from a bundled and largely regulated business model to an unbundled and market-based structure, particularly for the commodity and upstream segments of the natural gas value chain.

FEI began offering monthly balancing in 1988. The service operated as it does today, which allows for day-to-day over or under supply, with the month-end requirement to balance. If there was a shortfall at month end, the customer purchased monthly balancing gas at the interruptible sales rate. It was noted at the time that this service offered no incentive for customers to nominate accurately. Under this arrangement, FEI was unable to adequately recover costs, as heat or temperature sensitive customers would typically leave extra gas in the warmer or shoulder months, and require additional gas during periods when it is colder. Consequently, the utility was providing higher priced gas in return for extra gas left on the system by customers during warmer or lower demand periods. In order to account for this, in 1992, FEI applied for and the Commission approved a daily balanced procedure whereby customers paid for extra gas requirements on a day-to-day basis in accordance with their needs. This ensured, to some degree, that supply and billing matched with the service provided. This daily balancing procedure was imposed in the winter months only.

In 1993, the Phase B Rate Design Decision approved daily balancing for large volume interruptible customers (i.e., RS 22) in order for the utility to manage its transmission system pressures in an effective manner. Monthly balancing was allowed for small volume and interruptible customers (i.e., RS 25 and RS 27) on the basis that smaller volume customers would have fewer opportunities to access natural gas markets directly.

Since the original balancing rules were put in place as summarized above, the industry has changed significantly, specifically with respect to measurement and reporting improvements, technology, gas cycles, marketer sophistication and product and service standardization. FEI

proposes to update the transportation model to reflect these changes and eliminate monthly balancing.

49.2 What was FEI's original rationale for allowing a tolerance of 20%?

Response:

This balancing tolerance was originally offered under a proposed RS 32 Large Volume Gas Balancing service available as a substitute for monthly balancing. FEI was able to offer this tolerance based on a long term Westcoast Sales Agreement, which provided the operating flexibility and low or no cost swing supply. The Commission determined in the 1993 Phase B decision that the balancing provisions of RS 32 should be rolled into RS 22 (Order G-101-93, Decision pages 43 and 44).

50. Reference: Exhibit B-1, page 10-27

> Shipper agents managing daily balanced groups use the imbalance return service, which allows them access to their "banked" inventory on FEI's System. To build on the previous example, when imbalance return is authorized,[181] as shown in Figure 10-9 below, shipper agents can use their inventory as a source of gas supply in addition to the authorized supply at the interconnecting point. The authorized supply at the interconnecting point is 10,000 GJ combined with the amount of authorized imbalance return of 3,000 GJ for a total of 13,000 GJ. FEI then applies the tolerance calculation to determine if under-deliveries exceeded the tolerance. In this case, the shipper agent over-delivered by 600 GJ and no charges were incurred.

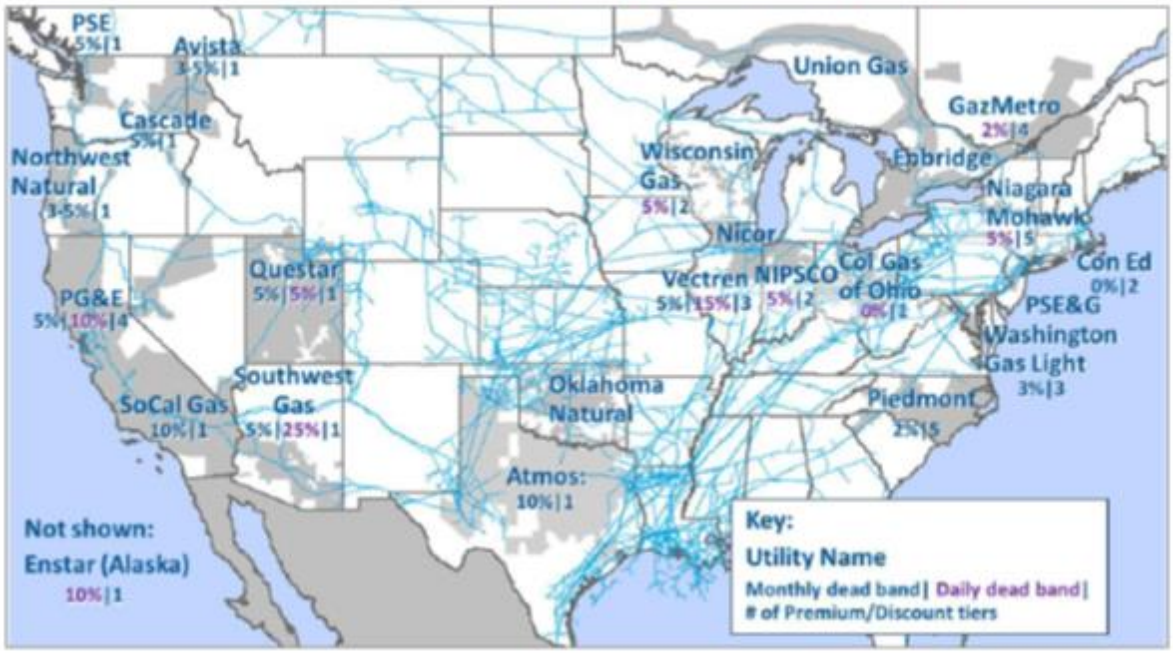
50.1 Please provide an approximation of the range of volumes of 'banked' inventory that shippers may have at their disposal at any given time.

Response:

Due to the Shipper Agents' balancing activities, the day-end inventory during 2015 ranged from 200,000 GJ to 1,000,000 GJ. FEI manages this volume of banked inventory, both in terms of holding and returning the supplies to Shipper Agents, using FEI's midstream resources including upstream and downstream storage, Westcoast OBA, or the buying and/or selling of gas on the day.

51. Reference: Exhibit B-1, page 10-31

Figure 10-11: Comparison of Selected Balancing Provisions among North American LDCs



51.1 FEI's Figure 10-11 does not include the Prairie provinces. Please explain why, and provide the evidence if it is available.

Response:

Black & Veatch provides the following response:

The original analysis sought to sample balancing provisions from diverse geographical regions that were similar to FEI in terms of urban/rural customer composition, size, and ownership of transmission pipeline. The utilities that best matched these criteria at the time of Black & Veatch's original analysis are represented in Figure 10-11.

Pursuant to this request, Black & Veatch examined the gas tariffs of ATCO Gas in Alberta and TransGas in Saskatchewan. ATCO Gas has a dead band of 5 percent that can be made slightly more flexible for smaller customers. TransGas, the gas transmission utility in Saskatchewan that is a subsidiary of SaskEnergy, sets a balancing tolerance each day for its shippers, which may vary from day-to-day but is not to exceed +/- 20 percent.

51.2 Are there any LDCs that do not allow for balancing tolerances at all?

Response:

Black & Veatch provides the following response:

It is unusual for a gas utility to provide a balancing tolerance of zero for its transportation customers and Shipper Agents. Black & Veatch noted one LDC, in its review of more than 20 LDCs, that arguably fits this criterion. Columbia Gas of Ohio does not provide a costless balancing tolerance. Rather, Shipper Agents may purchase balancing tolerances greater than zero up to a maximum of 4 percent.

51.2.1 If yes, please identify those LDCs.

Response:

Please refer to the response to CEC-FEI IR 1.51.2.

51.2.2 If yes, did FEI consider removing the balancing tolerances altogether? Please explain why or why not.

Response:

FEI did not give serious consideration to removing balancing tolerances altogether as this would represent a fundamental change to the model, which FEI believes is working well. The comparative research by Black & Veatch indicates it is not common industry practice for a gas utility to implement a zero balancing tolerance. Furthermore, a 5 percent tolerance is at the lower end of allowances to which utilities hold their customers. Tightening the balancing tolerance from 20 percent to 10 percent will provide a better incentive to reduce the large imbalance fluctuations experienced currently on FEI's system. By tightening the balancing tolerance, Shipper Agents will be incented to manage their customers' load more closely.

52. Reference: Exhibit B-1, page 10-32 to 10-33

> Transportation customers who maintain large imbalances within the month are receiving value from FEI's midstream resources. Black & Veatch was tasked by FEI to estimate the value of this service. In the Application to Amend the Monthly Balancing Charges for Rate Schedules 23, 25, 26 and 27, the Commission directed FEI to evaluate the extent to which FEI uses core gas cost resources to balance the overall transportation service imbalances for each day and the cost to the sales customers.[184] The research and analysis to derive the replacement costs below addresses this directive. A summary of this study is provided below, and the entire report is provided in Appendix 10-1.
>
> Black & Veatch developed a methodology to calculate the estimated replacement cost that transportation customers or shipper agents would have to incur to secure the balancing services currently provided by FEI (the Replacement Cost Analysis). As indicated in Table 10-7 below, the balancing service that FEI provides has market value.

Table 10-7: Replacement Cost of Balancing Services (Base Case)

	Total Replacement Costs	$/GJ
10%	$3,489,109	0.048
15%	$6,508,586	0.090
20%	$8,617,227	0.119

52.1 Please provide a brief overview of the Black and Veatch methodology for calculating the replacement value.

Response:

Black & Veatch provides the following response:

As discussed in Section 3.1 of Black & Veatch's Transportation Service Model Review (Appendix 10-1), the replacement cost analysis sought to determine the value of the pipeline and storage capacity resources that were being used to balance the transportation customers' deliveries. Black & Veatch used historical balancing data for each of the Shipper Agent groups to determine the extent to which the Shipper Agents were incurring imbalances on the system. Using this information, it was possible to derive an estimate of the amount of storage and transportation capacity that would be required to balance each of the individual Shipper Agents' accounts. With this estimate, Black & Veatch calculated the cost of the required capacity resources for all of the Shipper Agents combined, using published tariff rates from the relevant pipeline systems and storage facilities. Black & Veatch derived a per-gigajoule rate by dividing the total cost by the amount of annual transportation customer throughput on the system.

52.2 Please confirm that Black and Veatch's methodology does not provide the incremental cost to non-bypass customers of having Transportation customers utilize FEI's midstream resources.

Response:

FEI interprets the use of "non-bypass customers" in the question to mean sales customers under Rate Schedules 1 to 7.

Black & Veatch's methodology and analysis calculates the estimated replacement costs that transportation customers or shipper agents would have to incur to secure balancing services under a range of tolerances as shown in Table 10-7 of the Application. The analysis and methodology involved to calculate per GJ costs in Table 10-7 does represent an incremental cost to non-bypass sales customers.

53. Reference: Exhibit B-1, page 10-34

> In determining an appropriate tolerance threshold for FEI's transportation model, FEI considered research by Black & Veatch which indicates that some utilities hold their customers to a 5% tolerance. FEI considered this tolerance, but determined that 5% is too stringent, especially in light of the current rate schedule terms and conditions where FEI reserves the right to impose a 5% tolerance under supply restriction circumstances.
>
> FEI also considered the tolerances maintained by shipper agents operating under the transportation model today, under the current business rules with both daily and monthly provisions. Based on the analysis and balancing activity by transportation customers in 2014 and 2015, Table 10-9 below indicates that a number of shipper agents today (indicated below

53.1 Please elaborate on why 5% is too stringent a tolerance.

Response:

Please refer to the response to BCOAPO-FEI IR 1.10.3a.

53.2 The CEC interprets FEI's concern of its right to impose a 5% tolerance under supply restriction circumstances as being a desire to retain a different tolerance between the situations relating to supply restriction. Please confirm or explain otherwise.

Response:

Confirmed.

53.3 If confirmed, please explain why FEI wishes to retain a difference as opposed to eliminating the different tolerances altogether.

Response:

FEI wishes to retain a difference with balancing tolerances to provide a distinction between operating practices under normal weather versus under colder weather circumstances. The shift in balancing requirements from 20 percent to 10 percent for the majority of the year under

normal weather conditions represents a step in the right direction towards a tighter tolerance as adopted by other LDCs. This shift accomplishes two goals: (1) recognition of the value that FEI's balancing tolerance provides; and (2) the right incentive to Shipper Agents to manage their load more closely on a daily basis.

53.4 If confirmed, please e confirm that FEI could also lower and/or eliminate its tolerances under supply restriction conditions such that there is a difference between the two tolerances.

Response:

Confirmed. As reflected in the tariff today, FEI could lower its balancing tolerance from the existing 20 percent to 5 percent under supply restriction conditions. This tighter tolerance would apply to all transportation customers, both daily and monthly balanced.

54. Reference: Exhibit B-1, page 10-34

Table 10-8: Imbalance data under a 10% tolerance

Shipper Agent	Service Area	# Imb Days / Year	Annual Volume in Excess	Volume in Excess / Day	Demand / Day	Volume in Excess / Demand
Shipper Agent N	INL	287	-2,010	-6	8	-67%
Shipper Agent N	LML	219	-30,343	-85	230	-37%
Shipper Agent M	LML	216	-74,312	-204	467	-44%
Shipper Agent I	INL	210	-28,100	-77	414	-19%
Shipper Agent E	INL	203	-209,596	-574	2,128	-27%
Shipper Agent C	LML	185	-848,871	-2,325	13,829	-17%
Shipper Agent O	LML	170	-4,442	-12	124	-10%
Shipper Agent D	INL	169	-210,408	-576	3,401	-17%
Shipper Agent D	LML	161	-652,440	-1,788	14,446	-12%
Shipper Agent E	LML	149	-691,630	-1,895	13,008	-15%
Shipper Agent A	LML	137	-256,193	-702	19,970	-4%
Shipper Agent C	INL	115	-143,545	-393	8,173	-5%
Shipper Agent I	LML	109	-56,557	-155	2,591	-6%
Shipper Agent H	INL	17	-21,248	-58	5,293	-1%
Shipper Agent B	INL	12	-13,784	-38	15,191	0%
Shipper Agent A	INL	11	-59,806	-164	10,978	-1%
Shipper Agent F	INL	7	-22,161	-61	14,602	0%
Shipper Agent B	LML	5	-7,141	-20	15,641	0%
Shipper Agent K	INL	4	-2,767	-8	1,199	-1%
Shipper Agent L	LML	3	-2,049	-6	1,155	0%
Shipper Agent H	LML	1	-405	-1	3,027	0%
Shipper Agent G	INL	1	-921	-3	9,830	0%
Shipper Agent J	LML	1	-69	0	1,435	0%

54.1 Please identify whether each of the shippers is Daily or Monthly Balanced.

Response:

Table 10-8 has been revised to include a “Daily /Monthly” column which shows the daily and/or monthly groups each Shipper Agent holds by service area.

Shipper Agent	Daily / Monthly	Service Area	# Imb Days / Year	Annual Volume in Excess	Volume in Excess / Day	Demand / Day	Volume in Excess / Demand
Shipper Agent N	M	INL	287	-2,010	-6	8	-67%
Shipper Agent N	M	LML	219	-30,843	-85	230	-37%
Shipper Agent M	M	LML	216	-74,312	-204	467	-44%
Shipper Agent I	D & M	INL	210	-28,100	-77	414	-19%
Shipper Agent E[1]	D & M	INL	203	-209,596	-574	2,128	-27%
Shipper Agent C	D & M	LML	185	-848,871	-2,326	13,829	-17%
Shipper Agent O	M	LML	170	-4,442	-12	124	-10%
Shipper Agent D	D & M	INL	169	-210,408	-576	3,401	-17%
Shipper Agent D[2]	D & M	LML	161	-652,440	-1,788	14,446	-12%
Shipper Agent E	D & M	LML	149	-691,630	-1,895	13,008	-15%
Shipper Agent FEI[3]	M	LML & INL	148	-144,838	-397	3,833	-10%
Shipper Agent A	D & M	LML	137	-256,193	-702	19,970	-4%
Shipper Agent C	D & M	INL	115	-143,545	-393	8,173	-5%
Shipper Agent I	D & M	LML	109	-56,657	-155	2,591	-6%
Shipper Agent H	D	INL	17	-21,248	-58	5,293	-1%
Shipper Agent B[1]	D & M	INL	12	-13,784	-38	15,191	0%
Shipper Agent A[1]	D & M	INL	11	-59,806	-164	10,978	-1%
Shipper Agent F	D	INL	7	-22,161	-61	14,602	0%
Shipper Agent B	D	LML	5	-7,141	-20	15,641	0%
Shipper Agent K	D	INL	4	-2,767	-8	1,199	-1%
Shipper Agent L	D	LML	3	-2,049	-6	1,155	0%
Shipper Agent H	D	LML	1	-405	-1	3,027	0%
Shipper Agent G	D	INL	1	-921	-3	9,830	0%
Shipper Agent J	D	LML	1	-69	0	1,435	0%

[1] These Shipper Agents had a daily and a monthly group during the 2014 and 2015 years which this analysis was based on; however, at present these three Shipper Agents hold a daily group exclusively at the indicated location.

[2] This Shipper Agent had a daily and a monthly group during the 2014 and 2015 years which this analysis was based on; however, at present this Shipper Agent holds a monthly group exclusively at this location.

[3] Shipper Agent FEI is included as per the request in BCUC-FEI IR 1.60.9.1.

55. Reference: Exhibit B-1, page 10-36

> **10.7.6 FEI System Balancing – Appropriate Charges**
>
> As shown in Figures 10-8 and 10-9, the current charges for exceeding the balancing tolerance of 20% are $1.30/GJ in the winter and $0.30/GJ in the summer. As FEI is proposing to reduce the System balancing tolerance from 20% to 10%, FEI evaluated the level of charges that would be appropriate for the tighter balancing tolerance. FEI is proposing a tiered approach in order to layer in charges that are incrementally higher as threshold percentages are exceeded. FEI considered three ranges, 0-10%, 10-20% and greater than 20%. For shipper agents operating within the 0-10% range, FEI proposes to impose no penalty. To determine a slightly higher charge for the 10-20% range, FEI evaluated the variable costs involved in balancing the System, both to and from its storage resources.

55.1 Why does FEI wish to 'layer in' charges?

Response:

The charge of $1.30/GJ for exceeding the balancing tolerance of 20 percent in the winter that was noted in Section 10.7.6 of the Application as referenced above was a typographical error and is incorrect. Instead it should have been noted as $1.10/GJ in the winter. FEI confirms that all other references in the Application correctly specify the charge as $1.10/GJ in the winter.

The analysis in the Application demonstrates that there is a value to balance the system within a range of tolerances. FEI is proposing to tighten the existing tolerance from 20 percent to 10 percent and charge $0.25/GJ to capture the value of this balancing service within this range. FEI is not proposing any changes to the existing charges of $1.10/GJ in the winter and $0.30 in the summer when balancing tolerances exceed 20 percent.

The proposed tiered approach provides the appropriate signal to Shipper Agents. It provides an incentive to balance within 10 percent and a greater incentive to balance within 20 percent. Generally, the more the tolerance is exceeded, the greater the charge. This recognizes the value of the balancing service provided by FEI's midstream resources.

55.2 Is it FEI's objective to reduce, or to eliminate excess imbalances altogether? Please explain.

Response:

Tightening the tolerance to 10 percent and eliminating monthly balanced groups will help to incent Shipper Agents to balance their supply and demand requirements more closely on a daily basis, with the goal of reducing imbalances on FEI's system.

56. Reference: Exhibit B-1, page 10-37

> Based on the range in incremental variable costs, FEI is proposing to apply a mid-range charge of $0.25 CAD/GJ for the 10-20% range which would be applied in both the summer and winter months. Should the cost of gas exceed $5.00 US/MMBtu, which is the highest value FEI reviewed, FEI will apply to the Commission to update the charge.
>
> In the third tolerance range, shipper agents that exceed the 20% tolerance level would be subject to the same charges applied today, $1.10/GJ in the winter months and $0.30/GJ in the summer months. Any of these charges paid by shipper agents for either the 10-20% range or above 20% will be credited back to the midstream portfolio to recover costs for resources held on behalf of sales customers.
>
> Table 10-10 below summarizes the charges that would be imposed in the three tolerance ranges.
>
> **Table 10-10: Range of System Imbalance and Associated Charges**

Range	Winter Charge/GJ	Summer Charge/GJ
Tier 1: 0-10%	No fee	No fee
Tier 2: 10-20%	$0.25	$0.25
Tier 3: 20+%	$1.10	$0.30

56.1 Please provide an estimate of the amounts that FEI expects to be credited back to the midstream portfolio?

Response:

It is challenging to forecast the amount of balancing charges that will be collected and credited back to the midstream portfolio. This is because the proposed changes to the current transportation model could lead to different behavior by Shipper Agents than what has been experienced in the past.

Nevertheless, for illustration purposes, FEI calculated the potential charges that could have been collected in 2015 assuming all transportation groups were required to balance daily within a 10 percent tolerance, although this does not take into account any changes in behavior. The analysis includes both daily and monthly balanced groups, and simply applies the proposed charges in Table 10-10 to the under-delivered volumes by shipper agents. The following table shows approximately $1.4 million could have been collected in 2015 under those assumptions.

Estimated Balancing Charges

	Under-delivered Volume (GJ/Year)	Balancing Charges ($/Year)
0-10%	-668,442	No Charge
10%-20%	-563,735	($140,934)
>20%	-1,990,512	($1,299,237)
2015 Total	**-3,222,688**	**($1,440,170)**

56.2 Please provide FEI's best estimate of the costs that are incurred by non-bypass customers for holding resources on behalf of sales customers.

Response:

Non-bypass customers include both sales and transportation customers. FEI contracts for storage and transportation (midstream) resources for sales customers as discussed in the 2016/17 Annual Contracting Plan (ACP). The annual cost of holding those resources is approximately $170 million. FEI does not hold additional midstream resources for transportation customers.

57. Reference: Exhibit B-2, Appendix 11-2

FEI 2016 Rate Design Application — Appendix 11-2

Basis for Calculation of
Standard Charges Schedule

FEI Proposed Returned Payment Charge

Based on FEI's weighted average costs for 2015 of handling returned cheques and returned electronic fund transfers (EFT):

Line	Particulars		Notes
1			
2	Returned Payments in 2015		
3			
4	Returned cheques	215	
5	Returned EFTs	3,647	EFTs are related to preauthorized payment plan returns
6	Total Returned Payments	3,862	Line 4 + Line 5
7			
8	TD Canada Trust charges and Symcor charges		
9	Weighted average per returned payment	$ 1.45	
10			
11	Finance Department Processing Cost		
12	Cost of return cheques	$ 2.00	
13			
14	Customer Service Billing Department Processing Cost		
15	Cost of return payments	$ 3.91	
16			
17	Total cost of handling a return payment	$ 7.36	Line 9 + Line 12+ Line 16
18			
19	FEI Proposed Return Payment Charge	$ 8.00	

57.1 Please explain why FEI is proposing a charge of $8.00 when the cost is closer to $7.00 or $7.50.

Response:

FEI inadvertently rounded the proposed returned payment charge up to the next whole dollar of $8.00, rather than down to the nearest whole dollar of $7.00. Please find the corrected FEI General Terms and Conditions Standard Charges Schedule Original Page S-1, with a proposed Returned Payment Charge of $7.00 in Attachment 57.1.

58. Reference: Exhibit B-1-3, page 11-28

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.

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.

58.1 Please explain why Customer Education is expected to be lower in F2017 than F2016.

Response:

FEI notes an error in Table 11-6 referenced in the preamble. The line labelled "Annual Charge" should have been labelled "Annual Cost".

At the time that the Rate Design Application was filed, FEI had forecasted customer education costs of $70,000 in 2016 and $60,000 in 2017. The table below provides actual 2016 costs and volumes, as well as a revised forecast for 2017:

	Actual 2016	Forecast 2017
Staff Resources ($000's)	760	782
Customer Education ($000's)	27	100
Total Overhead ($000's)	786	882
Projected Volumes (000's GJs)	1,098	1,354
Annual Charge ($/GJ)	$0.72	$0.65

Actual customer education costs in 2016 were lower than forecast at approximately $27,000. Forecast customer education costs for 2017 are expected to increase due to the increased focus on the marine transportation segment. FEI anticipates increased spending as the marine segment is a relatively new market and, therefore, increased customer education is required in order to grow this market.

58.2 Why did FEI average the two years instead of using the Forecast for 2017? Please explain.

Response:

Although the average of the 2016 and 2017 forecasts is higher than the current OH&M charge as discussed above, FEI has recommended that the OH&M charge remain unchanged at $0.52 per GJ at this time. Please refer to the response to BCUC-FEI IR 1.37.1 for a longer-term forecast of the costs and volumes.

FEI has commenced a consultation process with NGT stakeholders to gather information and considerations for the rate structures and rate offerings for NGT. FEI will also review the appropriate level for the OH&M charge as part of that analysis, and report its findings as part of an application to be filed in 2018.

58.3 If FEI has a forecast available for F2018 please provide.

Response:

Please refer to the response to BCUC-FEI IR 1.37.1.

59. Reference: Exhibit B-1-1-1 page 13-20 and Exhibit B-1-1 page 13-20 and Cover Letter pages 1-2

Table 13-12: Revenue to Cost and Margin to Cost Ratios

Rate	R:C	M:C
Rate 1 Domestic (Residential) Service	90.5%	88.0%
Rate 2.1 General (Small Commercial) Service	108.3%	110.7%
Rate 2.2 General (Large Commercial) Service	113.2%	118.2%
Rate Schedule 25 General Firm Transportation Service	112.1%	112.1%

During the Workshop, staff raised a question about whether there should be a different Peak Load Carrying Capacity (PLCC) value used for Fort Nelson as a separate entity.[1] The PLCC is intended to recognize that there is capacity embedded in the minimum system and make an adjustment in the Peak Day Demand allocator to account for this. Since the Workshop, FEI considered the notion of using a Fort Nelson-specific PLCC both internally and in consultation with EES Consulting and concluded that using a Fort Nelson specific PLCC would be more appropriate given Fort Nelson has its own Minimum System Study and because it is a separate region for rate making purposes. Consequently, FEI has conducted further analysis using a separate PLCC for Fort Nelson.

As a result, in this evidentiary update, the COSA results for Fort Nelson have been revised reflecting the use of a specific PLCC for Fort Nelson of 1.178 GJ per customer (as compared to the PLCC of 0.205 GJ per customer for FEI as a whole including Fort Nelson). FEI believes that the use of the Fort Nelson-specific PLCC is appropriate since it uses data and analysis specific to the service area in which it is being applied and is also better for Fort Nelson customers because it reduces the magnitude of rate rebalancing.

Table 13-12: Revenue to Cost and Margin to Cost Ratios

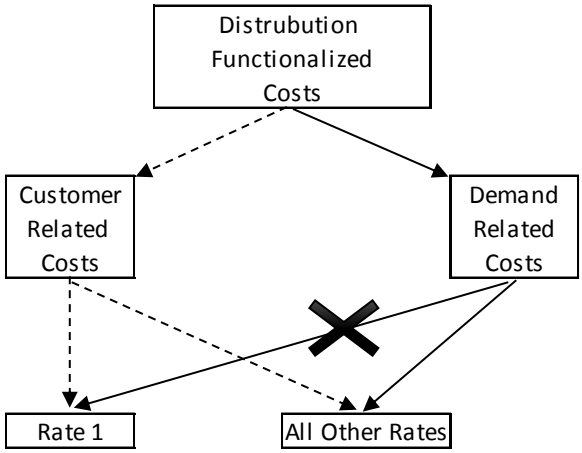
Rate	R:C	M:C
Rate 1 Domestic (Residential) Service	81.9%	77.5%
Rate 2.1 General (Small Commercial) Service	119.9%	126.4%
Rate 2.2 General (Large Commercial) Service	142.3%	164.5%
Rate Schedule 25 General Firm Transportation Service	112.1%	112.1%

59.1 The change in the PLCC has quite dramatically altered the COS Revenue to Cost ratios. Please elaborate on how the change in the PLCC resulted in this change.

Response:

The only change in the COSA for Fort Nelson when using a Fort Nelson specific PLCC is the allocation of Distribution Demand related costs. When a larger Fort Nelson specific PLCC is used, the minimum system has enough capacity to meet the peak day demand of RS 1 customers. For this reason, RS 1 is not allocated any more Distribution Demand related costs.

The diagram below may help show how using the Fort Nelson specific PLCC changed the cost allocations. Costs are functionalized to the Distribution function, which are then classified as either Demand or Customer related, which are then allocated to the various Rates. When using the Fort Nelson specific PLCC, the Customer-related costs in the Distribution function have enough capacity to serve RS 1 peak day demand, so no Demand related costs are allocated to RS 1.



The Distribution Demand-related cost allocation to Rate 1 decreased by $168 thousand. Consequently, the RS 1 M:C and R:C ratios increased.

60. Reference: Exhibit B-1-1-1 page 13-20

Table 13-12: Revenue to Cost and Margin to Cost Ratios

Rate	R:C	M:C
Rate 1 Domestic (Residential) Service	90.5%	88.0%
Rate 2.1 General (Small Commercial) Service	108.3%	110.7%
Rate 2.2 General (Large Commercial) Service	113.2%	118.2%
Rate Schedule 25 General Firm Transportation Service	112.1%	112.1%

Table 13-12 shows that R:C ratios for Rates 1 and 2.1 are within the range of reasonableness and Rate 2.2 and Rate Schedule 25 are above but near the upper bound of the range and that rebalancing may be necessary. FEI's proposal for rebalancing is discussed in Section 13.7.1.4.

60.1 Does FEI have a range of reasonableness it considers appropriate for the Margin to Cost ratio?

Response:

FEI does not have a range of reasonableness it considers appropriate for the Margin to Cost ratio. Historically, the range of reasonableness convention of 90 percent to 110 percent for gas utilities in BC has been on a revenue to cost ratio (i.e., including gas commodity and midstream costs and revenues) and that is FEI's view of how this guideline should be applied going forward.

60.1.1 If yes, please provide FEI's views as to the range of reasonableness for the Margin to Cost ratio.

Response:

Please refer to the response to CEC-FEI IR 1.60.1.

60.1.2 Please confirm that it is equally unfair for a customer group to be low on the Revenue to Cost Ratio as it is for customer groups to be high on the Revenue to Cost ratio.

Response:

If a rate schedule's revenue to cost (R:C) ratio falls within the range of reasonableness, the customers in that rate schedule are deemed to be paying rates that fairly recover the costs of serving them. Section 6.5.1 of the Application further describes the context of how R:C ratios are used in evaluating fairness among customer groups.

60.1.2.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC-FEI IR 1.60.1.2.

60.1.2.2 If confirmed, please confirm that Rate 1 is virtually on the lower bound of the 10% range of reasonableness and rebalancing is necessary.

Response:

Please refer to the response to CEC-FEI IR 1.60.1.2.

60.1.3 Please confirm that Rate 2.1 is approaching the upper bound of the 10% range of reasonableness.

Response:

Confirmed based on Table 13-12 reproduced in the preamble. Please refer to Exhibit B-1-1-1, page 13-51 for updated R:C and M:C ratios after rate design proposals and rebalancing.

60.2 Please calculate the rate impacts required for a rebalancing to unity implemented once every 10 years with a 1% adjustment to Rate Schedule 1 per year phased-in and proportionally equal reductions for those rate schedules higher than unity.

Response:

This responds to CEC-FEI IRs 1.60.2, 1.60.3 and 1.60.4.

FEI interprets this series of questions as asking what the annual bill impacts would be to phase all rates to unity over a ten year (CEC-FEI IR 1.60.2), five year (CEC-FEI IR 1.60.3) and three year (CEC-FEI IR 1.60.4) period. To respond to these questions, FEI assumed that all else is equal over the phase-in period, including delivery cost of service, cost of gas, customers, volumes, and cost allocations. The requested information is provided below showing the annual bill impact for each year in the phase-in period.

Rate	10 Year Phase In	5 Year Phase In	3 Year Phase In
1	+1.1%	+2.3%	+3.8%
2.1	-0.8%	-1.7%	-2.8%
2.2	-1.4%	-2.8%	-4.6%
25	-1.1%	-2.2%	-3.6%

Although FEI has provided a response to the question, a range of reasonableness is required when evaluating the fairness of customer's revenue responsibility. Please refer to the response to BCUC-FEI IR 1.14.1 for more information.

60.3 Please make the same calculation to show the rate impacts for a rate of implementation at 2% per year.

Response:

Please refer to the response to CEC-FEI IR 1.60.2.

60.4 Please make the same calculation for a rate of implementation at 3% per year.

Response:

Please refer to the response to CEC-FEI IR 1.60.2.

61. Reference: Exhibit B-1-1-1 page 13-20 and BC Clean Energy Act

Table 13-12: Revenue to Cost and Margin to Cost Ratios

Rate	R:C	M:C
Rate 1 Domestic (Residential) Service	90.5%	88.0%
Rate 2.1 General (Small Commercial) Service	108.3%	110.7%
Rate 2.2 General (Large Commercial) Service	113.2%	118.2%
Rate Schedule 25 General Firm Transportation Service	112.1%	112.1%

British Columbia's energy objectives

2 The following comprise British Columbia's energy objectives:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;

(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

(k) to encourage economic development and the creation and retention of jobs;

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

(p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

61.1 Please confirm that BC's Clean Energy Act, Section 2 Objectives, 2(g), 2(h) and 2(i) would support the provision of rates for natural gas that have revenue to cost ratios of one.

Response:

Not confirmed. As discussed in the Application, a revenue-to-cost ratio that falls within the range of reasonableness is appropriately deemed to be recovering its fair cost. It should be noted also that the *Utilities Commission Act* (UCA) requires the Commission to consider British Columbia's energy objectives only in respect of long term resource plans (section 44.1), expenditure schedules (section 44.2), CPCN approvals (section 46) and energy supply contracts (section 71). Consideration of British Columbia's energy objectives is not mentioned in the context of the rate setting provisions of the UCA (sections 58 to 61).

61.1.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC-FEI IR 1.61.1.

62. Exhibit B-1-1, page 13-23 and 13-24

> There is a low percentage of residential and commercial customers that benefit from the declining rates. This is because the majority of Fort Nelson's customers do not consume more than the minimum usage block per month and therefore are never billed under the second lower rate block. The result is that for the majority of Fort Nelson customers the current declining block rate structure is effectively the same as a flat rate.
>
> The graph below provides the percentage of residential customers with more than 30 GJ consumption in each month of the year.
>
> As can be seen from the two graphs above, approximately 18% of residential customers and 5% or less (i.e.24 or less) of the commercial customers in the coldest months of the year consume more than the minimum threshold for the second rate block in any month. In other words, the majority of residential and commercial customers are effectively paying a flat rate from the first block.

62.1 Did FEI consider altering the minimum usage block threshold for either residential or commercial customers, so that more customers could participate? Please explain.

Response:

Altering the minimum usage block threshold for either residential or commercial customers was not considered to be a feasible option because there are compelling reasons to change the existing declining block rate structure to a flat rate structure. As explained in Section 13.5.3 of the Application, the flat rate structure is the most common rate structure and is used by 7 out of 11 Canadian natural gas utilities. In addition, Government policy has changed significantly during the last 20 years. Declining block rates may send price signals that can discourage customer engagement in energy efficiency and conservation programs and activities. Finally, the customer research survey conducted by FEI indicates that the flat rate structure is preferred by the majority of Fort Nelson customers as it is simple, transparent and easier to understand.

63. Reference: Exhibit B-1-1, page 13-31

> ***13.5.4.4 Bill Impact Analysis***
>
> Any rate design proposal should consider the bill impact to customers and should be implemented in a way that minimizes the potential for rate shock. The analysis of residential customers' bill impact can be separated into two steps:
>
> (1) the bill impact due to a transition from bundled declining block rates with a minimum - daily charge to an unbundled flat rate structure with a daily Basic Charge; and
>
> (2) the impact from rebalancing and changes caused by rate design proposals in other rates/rate schedules as discussed in section 13.7.1.4.

63.1 Please confirm that the definition of 'rate shock' would not change from customer group to customer group.

Response:

FEI has not provided a definition of rate shock in the Application. As indicated in response to BCUC-FEI IR 1.3.1, there is no "one size fits all" approach to rate shock.

As indicated in response to CEC-FEI IR 1.1.3, in this Application FEI endeavored to limit customers' annual bill impact to 10 percent while balancing other rate design principles. FEI has applied this guideline to all customer groups.

63.1.1 If not confirmed, please elaborate on FEI's views as to how rate shock should be defined for each customer group.

Response:

Please refer to the responses to CEC-FEI IR 1.63.1 and BCUC-FEI IR 1.3.1.

64. Reference: Exhibit B-1-1, page 13-38 and page 13-40

> Third, the Fort Nelson threshold of 6,000 GJ/year is not consistent with the 2,000 GJ/year threshold utilized for commercial customers for FEI's other service areas. It is also higher than the threshold selected by five other Canadian utilities that were reviewed. As noted in Section 8.3, FEI conducted a review of other Canadian utilities and found that the threshold for small commercial customers ranged from 419 GJ/year for Gaz Metro to 5,500 GJ for Pacific Northern Gas (PNG). The 6,000 GJ threshold used for Fort Nelson is outside the range selected by these utilities. The Multi-Jurisdictional Review of Rates study is provided in Appendix 8.
>
> Finally, moving the threshold from 6,000 GJ/year to 2,000 GJ/year would not be overly disruptive to existing customers. It would only cause an estimated 9 small commercial customers to migrate to the large commercial rate. These migrating customers will receive a minor rate reduction due to the lower rates offered in Rate 2.2 as shown in Section 13.5.5.4 below.
>
> For consistency with the customer segmentation employed in FEI's other service areas, FEI proposes to set the threshold for Fort Nelson's RS 2.1 and Rate 2.2 at a normalized 2,000 GJ per year. The impact of this change is discussed further below.

64.1 What is the value of achieving consistency with the threshold utilized for commercial customers in FEI's other service areas, and with other Canadian utilities? Please explain.

Response:

The value of achieving consistency for commercial customers is in having the same applicability standards along with the General Terms and Conditions in defining customers into segments in all of FEI's service areas regardless of the location of the customer premise and the service that will be provided. Consistency in the rate schedules across FEI's service territories, including issues such as the 2,000 GJ threshold, also simplifies the development of common offerings, including energy efficiency and conservation programs.

65. Reference: Exhibit B-1-1, page 13-39

> The differentiation in the load factors, whether the threshold is 6,000 GJ/year or 2,000 GJ/year, provides evidentiary support for having a small and large commercial rate class, but the results do not lead to a preference for a threshold level. The results from Figure 13-14 above also do not provide a clear point at which to differentiate small and large commercial customers; however, visually, a differentiation would be appropriate that is somewhere within the range of 1,500 GJ to 2,000 GJ/year .

65.1 Please confirm that Load Factor is relevant in cost causation, and customers with higher load factors generally cause proportionally lower costs than those customers with lower load factors.

Response:

Confirmed that customers with higher load factors generally cause proportionately lower demand-related costs than customers with lower load factors. This can be seen from Table 9-5 in which Peak Day Demand (Line 3) for customer B is 81.9 percent of Customer A (249 GJ / 304 GJ), and similarly the average Demand Charge (Line 6) is also 81.9 percent ($1.291 / $1.576).

65.1.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC-FEI IR 1.65.1.

65.2 Would it be appropriate for FEI to distinguish customers based on load factor rather than consumption volume? Please explain why or why not.

Response:

In practice, FEI cannot distinguish small and large commercial customers based on load factor. FEI would require demand meters and would need to take a daily reading on all commercial customers to be able to do this. For this reason, annual load is the distinguishing factor between small and large commercial customers.

Where FEI has provided load factors in the Application for the rate schedules without demand meters (i.e., residential and commercial), the load factors are estimated.

Another reason that load factors would not be useful for distinguishing between small and large commercial is that some low volume customers have high load factors and some high volume customers have low load factors (even though the general trend is for higher volume commercial customers to have higher load factors).

Nevertheless, FEI is able to use the information on load factors in the Application to distinguish between small and large commercial, as seen in Figure 8-10. In Figure 8-10, there is a general leveling off of load factors at the 1,500 – 2,000 GJ annual consumption range. If FEI were to distinguish between small and large commercial using load factor, this is the approach that would need be used, suggesting a break between small and large commercial customers should be in the 1,500 to 2,000 GJ per year consumption range. The load factor evidence is therefore supportive of the proposed 2,000 GJ threshold.

65.2.1 If it would be appropriate, did FEI consider such an option? Please explain and elaborate on why FEI did not select this option.

Response:

Please refer to the response to CEC-FEI IR 1.65.2.

65.3 If FEI were to distinguish large commercial from small commercial based on Load Factor, what would FEI consider as the appropriate threshold to distinguish small commercial from large commercial. Please explain why.

Response:

Please refer to the response to CEC-FEI IR 1.65.2.

65.3.1 Please provide an overview of the magnitude of the impacts that an adjustment to FEI's identified Load Factor threshold could be expected to have on customer bills and on other customers, if any.

Response:

Please refer to the response to CEC-FEI IR 1.65.2.

66. Reference: Exhibit B-1-1 page 13-41

Table 13-20: Comparison between Small & Large Commercial using 6000 GJ Threshold

	Rate 2.1	Rate 2.2
Customer Weighting Factor	1.6	5.7
Use per Customer	425 GJ	8,103 GJ
Load Factor	34.4%	40.5%
Average Customer-related Cost / Customer / Day	$1.403	$3.693
Average Demand-Related & Energy-related Cost / GJ	$2.722	$2.291

The customer weighting factor is the relative cost of metering/measurement devices and service lines to serve commercial customers compared to residential customers. The higher weighting factor for Rate 2.2 compared to Rate 2.1 coupled with the average customer-related cost of service per customer per month leads to the expectation that large commercial customers should have a higher Basic Charge than small commercial customers.

66.1 Please provide the calculations behind the customer weighting factors.

Response:

Please refer to Attachment 66.1 for the requested information.

67. Reference: Exhibit B-1-1-1, page 13-50 and 13-51

Table 13-26: Revenue to Cost and Margin to Cost Ratios before rebalancing

Rate Schedule	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000)	Approximate Annual Bill Change	COSA after Rate Design Proposals R:C	COSA after Rate Design Proposals M:C
Rate 1 *Domestic (Residential) Service*	90.5%	88.0%	0.8	0.1%	90.9%	88.4%
Rate 2.1 *General (Small Commercial) Service*	108.3%	110.7%	(126.0)	0.1%	107.2%	109.4%
Rate 2.2 *General (Large Commercial) Service*	113.2%	118.2%	127.0	0.1%	114.5%	118.4%
Rate Schedule 25 *General Firm Transportation Service*	112.1%	112.1%	(1.8)	-1.2%	111.0%	111.0%

The table above shows that Rate 2.2 and RS 25 are outside the range of reasonableness. FEI's rebalancing proposals include the following adjustments to revenue responsibility:

- Decrease Rate 2.2 revenue by $16 thousand which will reduce the R:C ratio of Rate 2.2 to within the range of reasonableness.
- Increase Rate 1 revenue by $16 thousand to offset the decrease in revenue from Rate 2.2.

The following table presents the rebalancing amounts and Revenue to Cost (and Margin to Cost) ratios after rebalancing.

Table 13-27: Revenue to Cost and Margin to Cost Ratios after rebalancing

Rate Schedule	COSA after Rate Design Proposals R:C	COSA after Rate Design Proposals M:C	Rebalance Amount ($000)	Approximate Annual Bill Change	COSA after Rate Design Proposals and Rebalancing R:C	COSA after Rate Design Proposals and Rebalancing M:C
Rate 1 *Domestic (Residential) Service*	90.9%	88.4%	16.0	1.9%	91.9%	89.7%
Rate 2.1 *General (Small Commercial) Service*	107.2%	109.4%			107.2%	109.4%
Rate 2.2 *General (Large Commercial) Service*	114.5%	118.4%	(16.0)	-3.2%	109.9%	112.6%
Rate Schedule 25 *General Firm Transportation Service*	111.0%	111.0%			111.0%	111.0%

Fort Nelson rates must be adjusted to account for the shift in revenue responsibility. For Rate 1, FEI will increase the Basic Charge to $0.3003 per day so that the $16 thousand in revenue shift is recovered from all residential customers equally. FEI chose to collect all of the revenue shift through the Rate 1 Basic Charge because the lowest consuming customers receive the greatest rate reductions to their annual bills through the unbundling of Fort Nelson residential rates. Before rebalancing, a customer with annual consumption of 34 GJ (one quarter of the average) will experience a 7% decrease to their annual bill. By applying the adjustment only to the Basic Charge, FEI moderates the decrease to lower consuming customers making the adjustments more equitable between low and high consumers in Rate 1. This also results in Fort Nelson collecting more of its customer-related charges through the Basic Charge. Fort Nelson will collect approximately 19% of its revenue from Rate 1 through the Basic Charge; the customer-related costs in the COSA equal 62%.

The following figure illustrates Rate 1 customer bill impacts from all changes including unbundling and rebalancing. Each point on the graph is an individual customer.

67.1 Please provide the costs that would need to be transferred to RS 1 in order to bring the revenue to cost ratios to within a range of reasonableness of +/-5%.

Response:

In addition to the $16 thousand FEI proposes, another $50 thousand would need to be added to Fort Nelson Rate 1 residential customers to bring them to a 95 percent R:C ratio. The average Rate 1 customer would experience a 5.4 percent bill impact if this amount of rebalancing was made. When considering the revenue requirement rate change of nearly 7 percent for 2018, Rate 1 Fort Nelson customers would experience an approximate 12 percent rate change in 2018.

67.2 What opportunities are there for rate rebalancing in the future other than the current proceeding?

Response:

The current rate design application reflects an overall, full review of FEI's rate design with an updated COSA study to confirm that each rate schedule adequately recovers its allocated cost of service, and therefore it makes sense to adjust or rebalance rates which are outside the range of reasonableness as part of the current proceeding. Rate rebalancing is done in response to the results of the COSA study, which is typically updated every 5 years or so.

Attachment 37.1

19.3 *Order No. G-121-99 reduced the charge to $75/month (at that time). Please provide an updated review of the level of the Administration Charge, based on projected costs and customer forecasts for 2003, showing the staffing, staff cost and other costs required to provide the additional administration services needed by Transportation customers.*

Response

The attached table outlines the forecast costs for 2003 based on the incremental resources required to support the transport function. An additional cost relative to previous years is the web-based nomination and balancing system that will be operational later this year. The incremental IT cost is based on the current BCUC approved 8-year amortization of software. Should BC Gas' request for an accelerated 5-year amortization be approved, the monthly administration cost would increase by $3/month/customer.

BC GAS UTILITY LTD.
2003 REVENUE REQUIREMENTS AND
MULTI-YEAR PERFORMANCE BASED RATEMAKING
RESPONSE TO BCUC STAFF
INFORMATION REQUEST NO. 2

Annual Costs Related to Transport Customers
Estimated 2003
(Costs are benefit loaded)

Function:			# Req'd	Annual $	Total $	
Marketing						
		Industrial Reps.	1	71,000		
		Commercial Reps.	2	145,700		
		Management	1	118,000		
		Support	1	50,000		
		T-Coordinator	1	57,575		
		Supervisor	0.7	52,500		
					494,775	
	Billing					
		Billing Clerk	1	54,700		
		Supervisor	0.15	10,250		
					64,950	
	Measurement					
		Measurement Analyst	1	50,000		
					50,000	
	Legal/Regulatory					
		Legal	0.5	60,000		
		Regulatory	0.5	55,000		
		Support	1	50,000		
					165,000	
Infrastructure Costs						
		Nomination and Balancing System:				
		Capital Cost- $655,000 - Estimated Annual COS:			103,770	8 year levelized amortization
		Annual Maintenance:			50,000	
Total Annual Cost:					**$ 928,495**	
Estimated Annual # of Customers:					**1,115**	(Section H, Tab 7, Page 2.1)
Estimated Admin Fee, $/Customer/Month					**$ 69.39**	

the Commission is aware that customers, as well as municipalities and the Utility, have concerns about the franchise fee calculation methodology, the matter is not part of this proceeding.

After considering the foregoing specific matters and the general lack of opposition to the proposed tariff changes, **the Commission approves the tariff changes requested by BC Gas in its November 5, 2002 filing as revised in the hearing.**

7.5.2 Transportation Administration Charge

The Transportation Administration Charge is a fee paid by transportation service customers to recover the cost of the additional administration that these customers require. The charge in 2002 was $87 per month for each transportation customer. BC Gas calculated the forecast average cost of the incremental resources needed by transportation customers at $69.39 per month for 2003, and proposed that the fee be reduced to $70 per month (Exhibit 2, Tab 19, p. 3; T6:1262). There was no opposition to the proposal.

The Commission approves a Transportation Administration Charge of $70 per month for 2003.

7.6 Cost of Capital

7.6.1 Return on Common Equity

Under its automatic adjustment mechanism for determining the appropriate ROE for utilities, the Commission establishes at the end of each year, a new ROE for the upcoming year. For the past several years, BC Gas' ROE has been equivalent to the ROE established for the low-risk benchmark utility. For 2002, the ROE for the low-risk benchmark utility was set at 9.13 percent by Commission Letter No. L-43-01. For 2003, the ROE for the low-risk benchmark utility established in Commission Letter No. L-46-02 was 9.42 percent.

By letter dated December 18, 2002, BC Gas applied to increase its rates by $3.5 million effective January 1, 2003 for the revenue requirement increase arising from the higher ROE established for 2003. It asked that the same interim treatment as established by Commission Order No. G-90-02 for other components of BC Gas' rates be applied to the ROE increase. Thus, the ROE change would be effective January 1, 2003 and the related revenue requirement would be included from that date in the calculation of any shortfall recovery or surplus refund as specified in Commission Order No. G-90-02. **By Commission Order No. G-102-**

Attachment 57.1

Standard Charges Schedule

Application Charge	
Existing Installation	$15.00
New Installation	$15.00
New Installation - Manifold Meters	$15.00 per meter
New Installation - Vertical Subdivision	$15.00 per meter
Service Line Cost Allowance	
Other than a duplex	$2,150.00
Duplex	$4,300.00

Administrative Charges

Late Payment Charge	1.5% per month (19.56% per annum) on outstanding balance
Returned Payment Charge	$7.00

Interest on Cash Security Deposits

FortisBC Energy will pay interest on cash security deposits at FortisBC Energy's prime interest rate minus 2%. FortisBC Energy's prime interest rate is defined as the floating annual rate of interest which is equal to the rate of interest declared from time to time by FortisBC Energy's lead bank as its "prime rate" for loans in Canadian dollars.

Payment of interest will be credited to the Customer's account in January of each Year.

Metering Related Charges

Meter Testing Charges	
Meters rated at less than or equal to 14.2 m^3/Hour	$60.00
Meters rated greater than 14.2 m^3/Hour	Actual Costs of Removal and Replacement

Reactivation Charges

Performed During Regular Working Hours	$90.00 per hour
Performed After Regular Working Hours	$115.00 per hour

Deleted: Fees and
Deleted: Fee
Deleted: 25
Deleted: 25
Deleted: 25
Deleted: 25
Deleted: Dishonoured Cheque
Deleted: 208
Formatted: Highlight
Deleted: Disputed
Deleted: Fees
Deleted: G-21-14
Deleted: Director
Deleted: Services
Deleted: January 1, 2015
Deleted: September 30, 2016
Deleted: *Original signed by Erica Hamilton*
Deleted: 27

Attachment 66.1

Company: FortisBC Energy Utilities - Fort Nelson
Project Name: **2016 Rate Design Filing**
Model Type: **Amalgamated Customer Weighting Factors Study Model**

AMALGAMATED WEIGHTING FACTOR RESULTS	Rate 1 - Residential	Rate 2.1 - Small Commercial	Rate 2.2 - Large Commercial	Rate 25 - General Firm Transportation
2016 Weighting Factors	1.000	1.576	4.764	31.278

Customer Administration Weighting Factors	Rate 1 - Residential	Rate 2.1 - Small Commercial	Rate 2.2 - Large Commercial	Rate 25 - General Firm Transportation
2016 Weighting Factors	1.00	1.00	1.20	75.00

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
4																
5	Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	Col. (i) * Col. (j)	Class Per Unit Cost	Weighting Factor
6		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
7																
8	1	**RATE 1 - RESIDENTIAL**														
9	2	200	$ 71.60	$ 85			$ -		$ 1,535	$ 1,692			1,953	$ 3,304,587		
10	3	400	$ 169.75	$ 138			$ -		$ 1,535	$ 1,843			37	68,180		
11	4	600	$ 395.00	$ 1,612			$ 1,600		$ 1,535	$ 5,142			4	20,568		
12	5	1000	$ 611.60	$ 1,612			$ 1,600		$ 1,535	$ 5,359			3	16,076		
13	6	Rate 1 AMRs & EVCs								$ -				-		
14	7															
15	8	**Total**									**0**	**0**	**1,997**	**$ 3,409,410**	**$ 1,707**	**1.000**
16																
17	Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	Col. (i) * Col. (j)	Class Per Unit Cost	Weighting Factor
18		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
19																
20	1	**RATE 2 - SMALL COMMERCIAL**														
21	2	200	$ 71.60	$ 85			$ -		$ 1,341	$ 1,498			209	$ 313,073		
22	3	400	$ 169.75	$ 138			$ -		$ 1,535	$ 1,843			132	$ 243,236		
23	4	600	$ 395.00	$ 1,612			$ 1,600		$ 1,525	$ 5,132			9	$ 46,188		
24	5	1000	$ 611.60	$ 1,612			$ 1,600		$ 1,535	$ 5,359			92	$ 492,991		
25	6	3M	$ 2,381.00	$ 2,198			$ 1,600		$ 1,535	$ 7,714			15	$ 115,710		
26	7	7M	$ 2,790.00	$ 4,112			$ 1,600		$ 1,535	$ 10,037			1	$ 10,037		
27	8	11M	$ 3,039.00	$ 5,671			$ 3,200		$ 1,535	$ 13,445			1	$ 13,445		
28	9	Rate 1 AMRs & EVCs								$ -				-		
29	10															
30	11	**Total**									**0**	**0**	**459**	**$ 1,234,680**	**$ 2,690**	**1.576**
31																
32	Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	Col. (i) * Col. (j)	Class Per Unit Cost	Weighting Factor
33		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
34																
35	1	**RATE 3 - LARGE COMMERCIAL**														
36	2	200	$ 71.60	$ 85			$ -		$ 1,736	$ 1,821			1	$ 1,821		
37	3	1000	$ 611.60	$ 1,612			$ 1,600		$ 3,305	$ 6,517			13	$ 84,726		
38	4	3M	$ 2,381.00	$ 2,198			$ 1,600		$ 4,122	$ 7,920			9	$ 71,280		
39	5	5M	$ 2,580.00	$ 4,114			$ 1,600		$ 4,122	$ 9,836			2	$ 19,672		
40	6	7M	$ 2,790.00	$ 4,112			$ 1,600		$ 4,122	$ 9,834			5	$ 49,170		
41	7	7M ID	$ 1,848.00	$ 15,000			$ 1,600		$ 4,122	$ 20,722			1	$ 20,722		
42	8	Rate 3 AMRs & EVCs			$ 2,365					$ 2,365		2		4,730		
43	9															
44	10	**Total**									**0**	**2**	**31**	**$ 252,121**	**$ 8,133**	**4.764**
45																
46	Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	Col. (i) * Col. (j)	Class Per Unit Cost	Weighting Factor
47		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
48																
49	1	**RATE 25 - GENERAL FIRM TRANSPORTATION**														
50	2	11M ID	$ 1,997.00	$ 18,500			$ 3,200		$ 13,485	$ 37,182			1	$ 37,182		
51	3	T30 175# ID	$ 20,204.00	$ 28,000			$ 3,200		$ 13,485	$ 64,889			1	$ 64,889		
52	4	Rate 25 AMRs & EVCs			$ 2,365			$ 2,000		$ 4,365		2		4,730		
53	5															
54	6	**Total**									**0**	**2**	**2**	**106,801**	**$ 53,401**	**31.278**
55																
56																
57																

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
5	Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	Col. (i) * Col. (j)	Class Per Unit Cost	Weighting Factor
6		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
58																
59		**TOTAL METERS**										**4**	**2,489**			
60											AMRs	EVCs	Meters			