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June 9, 2017

Sent via eFile

FEI 2016 RATE DESIGN
EXHIBIT A2-8

To: All Registered Parties

Re: FortisBC Energy Inc. – 2016 Rate Design Application – Project No. 3698899 – Elenchus Research Associates Inc. Response to Information Requests

Commission staff submit the following document for the record in this proceeding:

Elenchus Research Associates, Inc.
Response to Commercial Energy Consumers Association of British Columbia Information Request
dated June 9, 2017

Sincerely,

Original signed by Katie Berezan for:

Patrick Wruck
Commission Secretary

ES/kbb
Enclosure

Reference: Exhibit A2-2, page 5

Frequency of COSA Studies: Cost of service allocation studies are conducted periodically by utilities to compare the costs attributable to the various customer classes with the revenues being collected from the customer classes. The frequency with which COSA studies are updated varies across jurisdictions and is typically linked to the rate setting process. Updates are typically expected at least every five years.

1.1. Please confirm that it would not be inappropriate timing for utilities to rebalance at the same time as cost of service studies are undertaken if the evidence is that the ratios are not at unity.

RESPONSE:

In practice, rates can only be rebalanced as part of a rate-setting process. Typically, a revenue requirement review, or general rate application (GRA) will result in the approval of an average, across the board rate adjustment. That across-the-board rate adjust is then modified to provide for differential rate increases so as to move the R:C ratios (or M:C ratios) toward or within the approved revenue to cost ratio ranges based on the approved methodology.

This standard regulatory approach would not preclude a regulator defining a COSA review as a rate setting process, perhaps to adjust across-the-board rate adjustments that had resulted from a previous GRA. However, the rate adjustments may not be considered appropriate in the absence of a public notice that rate adjustments are a possible outcome of the review. This note of caution is subject to legal opinion, which Elenchus is not qualified to provide.

Reference: Exhibit A2-2 page 6

Comparison of Cost and Revenues is done to determine to what extent the customer class is paying their fair share of the costs imposed on the utility. A revenue to cost ratio of 1.00 or above 1.00 means that the class is paying their fair share of costs or even more than their fair share. A revenue to cost ratio below 1.00 means that the class is not paying for their fair share of costs.

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.

2.1 Please provide the results from the Jurisdictional Review.

RESPONSE:

Please see response to BCUC IR 9.5.

2.2 Please confirm that it is not necessarily inappropriate for a utility to periodically rebalance to 1 using its best information.

RESPONSE:

Elenchus's view is that a utility should periodically update its COSA study and determine which, if any, classes have revenue to cost ratios that are outside the accepted range of reasonableness. If one or more ratios fall outside the accepted range, then rebalancing should be undertaken. Rebalancing should be undertaken to move all classes that are outside the approved range to the nearest boundary.

Given Elenchus' view that any ratio within the approved range represents full cost recovery, Elenchus does not consider it to be appropriate to periodically rebalance to revenue to cost ratios of 1.00. Elenchus is not aware of any jurisdiction that periodically rebalances rates so that all revenue to cost ratios are 1.00.

Reference: Exhibit A2-2 pages 7 and 8

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.

10. Freedom from controversies as to proper interpretation.

3.1 Please confirm that, to the extent the COSAs are done rationally and reasonably, none of the Bonbright principles would be violated by having periodic rebalancing to return rate classes to a revenue to cost ratio of 1.

RESPONSE:

Periodic rebalancing would not violate the Bonbright principles, although it would not be consistent with common practice.

One of the reasons for rebalancing to the range rather than to 1.00, is that the result would be likely to violate Bonbright's principle #3, since the differential rate increases would be less stable than results from rebalancing only when the ratio for a class is outside the range.

3 .1.1 If not confirmed, please explain why not.

RESPONSE:

N/A

3.2 Please confirm that none of the Bonbright principles are intended to facilitate subsidization from one or more rate classes to any other(s) or continuous long term subsidization of one rate class by others.

RESPONSE:

Confirmed.

Reference: Exhibit A2-2 page 9

To establish a principled cost allocation approach consistent with Bonbright's principle #6, regulators generally adopt the view that the class that causes specific costs should be expected to pay those costs. This is referred to at the cost causation principle. For example, AUC noted in Decision 2007-026 that allocation of costs for ATCO Gas should be based on each rate group's respective proportion of such costs. In general, customer related costs are allocated to rate classes on the basis of number of customers, commodity related costs are allocated on the basis of throughput and demand related costs are allocated on the basis of coincident peak demands or non-coincident peak demands8 . Enbridge also mentioned in its cost allocation studies that the overriding principle for proper classification and allocation of costs is to do so based on the causation of costs that are approved by the OEB9.

4.1 Please confirm that cost causation as an over-riding principle for proper classification and allocation of costs is also appropriate for FortisBC.

RESPONSE:

Confirmed.

4.2 How do utilities account, if at all, for costs that may be initially 'caused' by one customer group, and then later utilized by other customer groups because the original customer group does not utilize the assets to the extent originally anticipated? Please explain.

RESPONSE:

A COSA study is a picture taken at a point in time reflecting how customers use the shared utility's assets and reflects the costs imposed by customers on the utility in the test year used for the COSA. Consequently, the COSA reflects how the assets are currently used as is "blind" to past use.

Reference: Exhibit A2-2, page 10

4.1.3 MT. HAYES LNG STORAGE

This function includes costs related to the operation and maintenance of the facility and allocation of general and intangible plant assets and expenses.

This facility has a dual purpose of serving as a gas supply storage facility and a transmission facility which provides additional transmission system capacity to serve customers 11 and FEI in the GOSA study reclassified a portion of Mt. Hayes costs to the transmission function. This treatment is unusual. Elenchus is not aware of analogous methodologies being used in Canada in allocating the costs of storage or LNG to customer classes. However, it is Elenchus understanding that this unique treatment reflects the unique role that Mt. Hayes LNG Storage serves in the FEI system. Storage is more typically a purely midstream asset, but Mt. Hayes LNG Storage also provides benefit to the downstream gas distribution system. Consequently, it is appropriate to reflect the multi-faceted role of the facility in the cost of service allocation methodology.

5 .1 How are LNG storage costs typically allocated in other jurisdictions? Please explain.

RESPONSE:

Please refer to responses to BCUC IR 3.1.

5.2 Are there other jurisdictions that Elenchus is aware of which do, or may have, analogous circumstances to FEI' s in which midstream storage assets also provide benefits to the downstream gas distribution system?

RESPONSE:

Please refer to responses to BCUC IR 3.1.

5.2.1 If yes, please provide those jurisdictions and provide an overview of those situations and how the costs are allocated.

RESPONSE:

Please refer to responses to BCUC IR 3.1.

Reference: Exhibit A2-2, page 11

4.1.5 DISTRIBUTION

This function includes assets and expenses related to the distribution pressure and intermediate pressure pipe assets, meter installation and exchange, service lines, maintenance, training, distribution pipe operations, emergency management and an allocation of general costs and intangible plant assets and expenses.

6.1 Please provide the rationale for including emergency management in 'distribution'.

RESPONSE:

Elenchus understands that emergency management refers to emergency situations that arise related to the distribution system and therefore it is appropriate to include the emergency management under the distribution function.

Reference: Exhibit A2-2, page 12

Table 1: Cost Allocation Functionalization

Functions	FEI	Enbridge	Union Gas	ATCO
Gas	Gas supply	Gas supply	Production and gathering	
Storage	Tilbury Storage	Storage	Local storage	
	Mt. Hayes Storage		Underground storage	
Transmission	Transmission	Sales pressure regulators	Transmission	Transmission
Distribution	Distribution	Distribution pressure regulators	Distribution (Southern Ontario)	Distribution meters
		Services Mains	Distribution (Northern Ontario)	Distribution Mains
		Meters	Intangible plant	Meter reading
		Rental Equipment	General Plant	Distribution Services
Marketing	Marketing	Sales/ Marketing		Consumer education Call Centre Retailer Service Customer Service
Accounting	Customer Accounting	Customer Accounting		Administration Billing
		Unidentifiable		

7.1. How does Union Gas allocate overhead service-related expenditures such as Marketing and Accounting?

RESPONSE:

For Union Gas, general operating and engineering activity related expenses are functionalized primarily on the basis of an analysis of activities conducted by budget centre managers for their departments. Administrative and general group benefits expenses are functionalized on the basis of direct labour relationships. The remaining administrative and general expenses are functionalized in proportion to the functionalization of all other O&M expenses.[1] For example, customer billing and accounting operating expenses for large industrial billings are assigned to storage and transmission functions.[2] The functionalized costs are allocated to customer classes depending on the classification (i.e. demand, commodity, customer) of those costs.

[1] OEB EB-2011-0210, Exhibit G3, Tab 1, Schedule 1, page 5 of 18.
[2] OEB EB-2011-0210, Exhibit G3, Tab 1, Schedule 1, Appendix A, page 1 of 8.

7.2 How does ATCO allocate costs related to gas and storage?

RESPONSE:

The Gas Supply and Storage functions were removed in its cost of service study in ATCO's 2011-2012 General Rate Application Phase II as per the Negotiated Settlement from 2008-2009 GRA Phase II[1]. The removal of Gas Supply function is due to the fact that with the transfer of ATCO's retail business to Direct Energy Regulated Services, ATCO did not functionalize any costs to this function[2]. The Storage function was removed because of the removal Carbon related assets from rate base[3].

[1] ATCO Gas, 2008-2009 General Rate Application – Phase II, Negotiated Settlement, Appendix 3, page 13 of 29.
[2] EUB (now AUC) Decision 2007-026 (April 26, 2007), page 32.
[3] AUC Decision 2010-496 (October 19, 2010).

Reference: Exhibit A2-2, page 13

Based on Elenchus experience, in order to determine the proportion of distribution costs that are customer related and the proportion that are demand related, there are two generally accepted methodologies being used by utilities: Minimum System method and Zero Intercept method.

8 .1 If there are any other methods, please briefly describe any other less conventional methodologies that Elenchus is aware of that are utilized by utilities to determine the proportion of distribution costs that are customer related and the proportion that are demand related.

RESPONSE:

Some utilities do not conduct their own minimum system study or zero intercept method and use the proportions used by other utilities to classify distribution assets and/or expenses between customer and demand related.

Some jurisdictions have default values set by the regulator for the proportion of customer related based on the utility's density: high density Urban utilities would use a smaller percentage of customer related, while rural less dense utilities would use a larger proportion of customer related when classifying distribution assets.

Some utilities may just arbitrarily classify distribution assets as: 100% demand, 100% customer, or 50% customer related.

The primary reason for adopting these alternatives appears to be simplicity.

8.2 Please provide hypothetical examples for any other methodology, if any.

RESPONSE:

Please see response above to IR 8.1.

8.3 Please provide a list of Pros and Cons for each methodology, including any other methodologies that Elenchus identified in CEC 1.8.1.

RESPONSE:

The pros of using the methodologies listed in 8.1 are that they are:

- Simple to use; and
- Do not require extensive data collection of the utility's own distribution system: e.g. replacement cost, inventory.

The con of using the methodologies listed in 8.1 are that they:

- They have no analytic basis and as a result they do not necessarily reflect the utility's own distribution system.

Reference: Exhibit A2-2 page 13 and page 14 and page 14

The Minimum System method calculates the proportion of distribution asset costs that are customer related by taking the ratio of the costs of the smallest distribution assets, e.g. smallest main, to the costs of all similar assets, e.g. all rnains. This process is used to determine the customer components for mains. A common critique of this method is that the customer related portion of the distribution system is able to carry some demand, therefore, some demand related costs would be included in the customer component. To address this concern an adjustment is made to take into consideration the demand that can be supplied through the minimum system. The adjustment is the PLCC.

The PLCC adjustment determines the theoretical capacity of the minimum system, that is, the capacity of the smallest distribution asset. The capacity of the smallest distribution asset is divided by the number of customers served by the distribution system and an average minimum system capacity per customer is calculated. This average minimum capacity is multiplied by the number of customers in each rate class and the corresponding amount is deducted from the peak demand for that rate class to derive the adjusted peak demand. The adjusted peak demand is used to allocate demand related distribution assets and costs.

The Zero Intercept method calculates the customer related component of a distribution asset type by plotting a graph of the unit costs of different size similar assets and using the value at the zero intercept in the graph to represent the customer component of the asset costs. A common critique of this method is that a utility may not have enough data to plot a proper graph, or the method may result in a negative value at zero intercept.

9 .1 Please discuss how the two methodologies compare in terms of the results that would likely be delivered if each methodology were applied to the same set of circumstances. If there are circumstances that tend to create certain results under one methodology that would be different under the other, please identify these circumstances and explain.

RESPONSE:

As is evident from the excellent and concise description of the two methods provided in the question, the two methodologies take fundamentally different approaches. Elenchus does not see any basis for predicting a consistent difference in the results. Differences between the two approaches would appear to depend on the details of the system to which the two methods are being applied.

For example, it is reasonable to expect that distribution assets with many connected customers would have a relatively large PLCC adjustment to the minimum system result; whereas, the number of connected customers would have no impact on the Zero Intercept method. This factor would give rise to differences in result that would not be consistent across different utilities.

It is also likely that costs for all assets considered for the Zero Intercept method would differ across utilities due to factors such as the terrain of the service area (i.e., rock versus farmland). Such differences may affect the slope of the line in the Zero-Intercept method while the Minimum System method would start with a point estimate and would not be affected by the slope of the difference for different pipe sizes.

Elenchus is not aware of any generalizable conclusions that can be drawn about the two methods except that different results can be expected.

9.2 Please provide a hypothetical example with quantification of each of the two methodologies using the same hypothetical set of costs.

RESPONSE:

Elenchus does not consider this to be a practical or meaningful exercise. Hypothetical examples could be constructed to produce a wide range of possible results, with the results for the Minimum System method be larger than, similar to or smaller than the results of the Zero Intercept method.

The only relevant and meaningful comparison to undertake would be a comparison of the two methods for an actual utility using its actual data. To do this properly would involve access to all relevant data and significant effort.

Elenchus therefore respectfully declines to respond to this question.

Reference: Exhibit A2-2 page 16

4.2.6 Elenchus Analysis of FEI's Classification Methods

Demand, energy and customer are the standard classifications used in COSA studies and Elenchus agrees with the classifications used by FEI in the COSA studies. Elenchus is not aware of any other classification method used in cost of service allocation studies. Sometimes the term commodity is the term used instead of energy.

The use of minimum system with PLCC adjustment and/or the zero intercept method has been accepted as a classification methodology for distribution related assets and costs based on Elenchus experience.

Elenchus has seen the minimum system method applied more often by utilities than the zero intercept method.

10.1 Please provide Elenchus' views as to pros and cons of the ATCO Negotiated Settlement methodology.

RESPONSE:

The Negotiated Settlement from ATCO 2008-2009 GRA-Phase II resulted in a negotiated classification of costs (e.g. Distribution Service Function be classified 100% to the Customer component and then distributed to rate groups on the basis of Weighted Customers), rather than using the Minimum Plant Method. AUC directed ATCO to bring this topic forward at the next GRA Phase Application.

Elenchus is aware that classifying distribution as 100% demand has been used by utilities and weighted number of customers has also been used by utilities.

As stated by Elenchus in response to IR 8.3 above the pros of the negotiated methodology are:

- Simple to use,
- Simple to understand,
- No extensive distribution system data required, and
- Agreed by stakeholders

The cons of the negotiated methodology are that:

- it possibly may not reflect the utility's circumstances, or
- results may be quite different than using a minimum system or zero intercept methodology approach.

Elenchus exercises caution in giving weight to any single part of any negotiated settlement when the context of the overall package agreed to cannot be taken into account.

Reference: Exhibit A2-2 page 16

FEI uses the coincident peak (CP) methodology to allocate demand related assets and expenses to rate schedules. FEI states in its evidence that: *FEI's delivery system has generally been constructed to meet the peak day (coldest day) demand of all its firm service customers*[1]. FEI allocates demand related costs based on the rate schedule's contribution to the system peak.

The peak day demand estimate for each rate schedule uses regional temperatures data and is based on a regression analysis that uses average monthly temperature and actual demand data for ten months (excludes July and August). For heat sensitive loads, load factors are used in order to determine the peak day demand and data for three years are used and are averaged.

11.1 Please comment on the purpose of excluding July and August data from the demand data.

RESPONSE:

It is Elenchus understanding that FEI excluded the month of July and August from the demand data because during those months there is no heating load.

[1] Exhibit B-1, Section 6.3.6, page 6-21, lines 15 to 16

11.2 Please quantify and comment on the impact of excluding July and August data from the demand data.

RESPONSE:

Elenchus does not have the data to be able to respond to this question.

11.3 Please comment on the validity of excluding July and August data from the demand data.

RESPONSE:

Elenchus understands that the purpose of the regression analysis conducted by FEI using average monthly temperature and actual demand data for ten months is to estimate the peak day demand. Peak day demand is heat sensitive and excluding months when there is no heating is consistent with the principles of regression analysis.

Reference: Exhibit A2-2, pages 17 and 18 and Appendix A pages 1 and 3

4.3.4 Elenchus Analysis of FEI's Allocation Methods

Elenchus agrees with the allocators used by FEI in the COSA study and they are the standard allocators used by utilities in COSA studies. Elenchus experience is that non-coincident peak (NCP) is used to allocate distribution demand related assets and expenses by electric utilities.

In response to Elenchus question to FEI, (included as Appendix A to this report), on using non-coincident peak as an allocator for distribution demand related assets and expenses, FEI stated that:

a) it does not have the necessary metering in place in order to calculate NCP by customer class,

b) approximately 80% of FEI's customers volumes are heat sensitive and the NCP would be the same as their coincident demand in the peak day and

c) that the FEI system is designed to satisfy the demand during the peak day.

FEI summarizes its response by stating that*: "while FEI refers to its Peak Day demand as a coincident peak, it is derived from the sum of the various customer class loads under a design day event, which is similar to the standard approach to developing an NCP based on a measurement of historic system peak day loads. As a result, there is very little difference between the FEI's CP demand and the NCP demand. FEI's method to calculate Peak Day and allocate costs based on the results is appropriate as it is aligned with the way in which FEI plans and builds its distribution system."*

Elenchus accepts FEI's explanation of the reasons for using CP as an allocator instead of NCP and that even if the data would be available, the results would be unchanged.

First, it is important to note that FEI does not have demand meters in place to measure the CP and NCP for 99% of its customers.

Coincident Peak, generally speaking, refers to demand among a group of customers that coincides with total demand on the system at that time. A customer's CP is usually calculated from meter readings taken at the time when the customer's demand is likely to be highest; however, 99 percent of FEI's customers do not have demand meters, meaning daily consumption data for these customers is unavailable.

In summary, while FEI refers to its Peak Day demand as a coincident peak, it is derived from the sum of the various customer class loads under a design day event, which is similar to the standard approach to developing an NCP based on a measurement of historic system peak day loads. As a result, there is very little

difference between the FEI's CP demand and the NCP demand. FEI's method to calculate Peak Day and allocate costs based on the results is appropriate as it is aligned with the way in which FEI plans and builds its distribution system.

12.1 Would Demand Meters offer any other benefits in terms of rate design and/or rate setting? Please explain.

RESPONSE:

In responding to this question, Elenchus considers it to be important to distinguish between demand meters, which measure peak demand within a period (e.g., monthly) but do not track demand throughout the period (i.e., load shape) and Advanced Metering Infrastructure (AMI, a.k.a., smart meters) which have been, or are being, deployed by many electric utilities across Canada and internationally.

AMI offers significant operational benefits, such as the ability to identify problems on the system (outages result in demand dropping to zero).

Demand meters do not offer the same operational benefits since the demand reading is not available on a real-time basis. In additional, monthly customer-specific peak demand information does not provide significantly more information for system planning and engineering purpose than can be obtained through the deployment of metering laterals throughout the system

While there may be circumstances where demand meters will have value beyond facilitating the rate design and rate-setting feature of implementing demand charges, Elenchus is not aware of significant additional benefits.

Reference: Exhibit A2-2, page 19 and page 22

4.5.1Test Year

FEI used the approved costs for its 2016 test year in its COSA study. The approved revenue requirement is $1,237.5 million and the approved asset rate base is $3,692.7 million[1].

4.5.2 Operating and Maintenance (O&M) Expenses

FEI broke down its approved 2016 O&M expenses into functions using the same percentage of its actual 2015 O&M results

The test year used in a cost of service allocation study, based on Elenchus experience, reflects the normal operating conditions for a utility and known changes from past operations should be incorporated in the test year data as known adjustments.

Similar to FEI's test year approach, AUC directed gas utilities to set going-in rates on the basis of a notional year revenue requirement using actual costs experienced during generation Performance Based Regulation (PBR) term with any necessary adjustments to reflect individual distribution utility known or anticipated anomalies[2]. There are also gas utilities in U.S. (e.g. Atmos Energy Corporation[3]) that use a historic test year adjusted for known and measurable changes.

13.1 Would there be any advantage to using an average of multiple test years in establishing the appropriate percentages for O&M? Please explain why or why not.

RESPONSE:

In Elenchus' experience, it would be unusual for the average of multiple test years to provide more representative percentages for O&M. Average could be appropriate if there were random fluctuations from year to year. It would not be appropriate if there is a shift in the percentages (e.g., due to a staff reduction program) or if there is a trend to the percentages for some reason. Elenchus' observation is that while trends and downsizing events occur, significant fluctuations in O&M percentages would be unusual.

[1] Exhibit B-1, Section 6.3.1.1, Table 6-1, page 6-6
[2] AUC Errata to Decision 20414-D01-2016, page 11.
[3] Railroad Commission of Texas, Gas Utility Docket No. 10428, page 2 of 10.

13.2 Please identify any differences that may exist between the AUC method and the FEI method.

RESPONSE:

Both the AUC and the FEI method determine revenue requirement under the performance based ratemaking mechanism using a test year cost with adjustments for known and measurable changes. However, the FEI method uses approved forecast costs from the most recent year as the starting base for the PBR term while AUC directs utilities to use actual costs from the lowest year during the prior PBR term as the starting point.

The AUC implemented Performance Based Regulation (PBR) plans for certain electric and gas distribution utilities in Alberta in Decision 2012-237 for a five-year term (i.e. 2013-2017). This PBR framework provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism[1]. The revenue requirement was determined on the basis of a notional year using actual costs experienced during the PBR term with necessary adjustments for known or anticipated anomalies[2]. Specifically, the O&M costs are based on the lowest O&M cost year during the prior five year PBR term with adjustments as necessary[3]. AUC is of the view that Phase II applications should be filed and implemented on a go-forward basis any time during the PBR term and will be accepted for consideration which are intended to take effect sometime following the commencement of the PBR plans on a prospective basis[4].

FEI uses the approved gross O&M regulated under PBR for 2016 test year[5].

[1] AUC Errata to Decision 20414-D01-2016 (December 16, 2016), page 4.
[2] Ibid, page 11.
[3] Ibid, page 12.
[4] Ibid, page 17.
[5] Exhibit B-1, Section 6, page 6-7.

13.2.1 Please provide Elenchus' view of the Pros and Cons for any differences between the AUC method and the FEI method.

RESPONSE:

AUC method:

Pros:

- Using the lowest cost year encourages performance that at least as good as the best year in the prior PBR term.

Cons:

- The test year actual amount could be different from prior year situation significantly.

FEI method:

Pros:

- The forecast amount can be fully reviewed through a public hearing.
- The forecast costs will reflect changing circumstances and may result in rates better reflective of the forecast year.

Cons:

- Utilities may have the incentives to over forecast the O&M costs.
- Increased regulatory burden of reviewing the reasonableness of forecast costs (e.g. all non-recurring O&M items are removed form the forecast).

13.3 Please clarify the term 'generation Performance Based Ratemaking'.

RESPONSE:

This PBR framework provides a rate-setting mechanism that envisions a series of generations, with the regime being modified with each new generation. For clarity, it does not refer to the electricity generation function.

PBR regime are generally based on a formula that adjusts rates annually by means of an indexing mechanism[1]. The current generation of PBR term in Alberta is for five years from 2013 to 2017 and the next generation is for 2018 to 2022. The regime is likely to evolve and have some differences in the next generation of PBR.

[1] AUC Errata to Decision 20414-D01-2016 (December 16, 2016), page 4.

13.4 Please provide an overview of any other methods other companies operating under **PBR** use to determine the appropriate costs for the starting point.

RESPONSE:

In Ontario, gas distributors are also regulated under Performance Based Approach where gas utilities have two rate setting options[1]. The Union PBR regime is a five-year price cap incentive plan in which rates for the starting point were set through a cost of service process based on forecast costs. The rates for years two to five are adjusted using a formula specific to each year.

Enbridge sets rates under the custom incentive rate-setting plan in which rates for each year of the five-year term were set out based on the forecast costs for each year. There was no starting point that was used as a basis for escalating rates.

[1] OEB Filing Requirements for Natural Gas Rate Applications, February 16, 2017, page 4.

Reference: Exhibit A2-2, page 20

FEI's biomethane service allows customers to allocate a portion of their natural gas as renewable natural gas. Biomethane is a renewable and carbon neutral energy source that reduces GHG emissions when replacing natural gas[1]. The biomethane related costs are generally included in a variance account to be recovered from biomethane customers consistent with an order from the Commission. The biomethane related costs that remain in the COSA study to be functionalized and allocated are the costs of six interconnections and these costs have been functionalized as distribution and are allocated to customers with access to the biomethane program[2]. Customers in rate schedules 1B (residential), 2B (small commercial), 3B (large commercial), 5B (general firm) and 11B (large volume interruptible) are eligible for this program

14.1 Please comment on the appropriateness of allocating costs to customers who are eligible for a program rather than to those customers who are participating in the program, and discuss whether this is common practice.

RESPONSE:

In a COSA, costs are allocated to classes of customer, not to individual customers: hence, FEI's methodology is consistent with standard practice. To handle the allocation differently would require the creation for purposes of the COSA and rate setting two subclasses consisting of participants and non-participants.

An analogous COSA methodology is the allocation of Demand Side Management costs, which are often allocated to classes based on the DSM program costs associated with the programs that are available to each class. No attempt is made to allocate costs only to the participating customers within the class.

[1] Exhibit B-1, Section 6.3.1.5, page 6-9, lines 20 to 21
[2] Exhibit B-1, Section 6.3.1.6, page 6-9, lines 19 to 28

Reference: Exhibit A2-2, page 21

4.5.8 Load Factor Adjustment to RS 5 Customers

FEI is proposing to adjust the load factor adjustment for RS 5 customers to use the RS 5's three-year average instead of the 50% deemed load factor that was negotiated in the 1996 rate design application. The load factor is used to allocate midstream costs to RS 5 customers and FEI contracts for midstream resources based on a calculated load factor for RS 5 customers, not a deemed load factor[1].

15.1 Please provide Elenchus' views as to the appropriateness of using a 3 year average, as compared to any other term, such as 5 years.

RESPONSE:

The most appropriate load factor adjustment is the one that provides the most reasonable estimate to the load factor that is likely to occur in the test year. This could be based on one year, three years, five years, or any other number of years, depending on the specific situation being considered.

Where there is past volatility in the load factor that is expected to continue, averaging several years is a method that can be used to provide greater stability and a better forecast for the test year than relying on a single historic year. A five-year average, or an average of some other number of years, cannot be assumed to provide a better or worse forecast than the three-year average unless there is evidence that the additional years are either more or less representative of the test year.

Three years my well provide a reasonable balance between more years (greater stability) and fewer years (more similar to the test year). Elenchus cannot provide a more definitive answer in the absence of extensive analysis of the historical data.

[1] Exhibit B-1, Section 6.4.2.1, page 6-30, lines 6 to 11

Reference: Exhibit A2-2, pages 21 and 22

4.5.9 Known and Measurable Changes

There are three approved projects that FEI expects to have in service in 2018 for which their costs have been included in the COSA study:

- Lower Mainland Intermediate Pressure System Upgrade
- Coastal Transmission System Upgrade
- Tilbury Expansion

Only the Tilbury project has associated revenues and FEI has used a ten year levelized margin approach to reflect the impact of the project on FEI's customers.

The 10 year horizon used by FEI in its COSA study to reflect the impact of the Tilbury Expansion project is not consistent with standard practice. Utilities undertake new investments on an ongoing basis and as a result the revenue requirement in any year includes costs for older assets that have a diminished impact on the total revenue requirement as well as new assets that have a high initial impact. Except in extraordinary cases, it would be inconsistent to levelize the costs of a single project while not levelizing the costs associated with other investments. Elenchus is not aware of any unique aspects of the Tilbury Expansion Project that make its impact on customers generally, or any class of customers, that justify exceptional treatment of this project in the form of levelizing its costs for purposes of the COSA.

16.1 What are FEI's other options in accounting for the Tilbury project? Please describe.

RESPONSE:

Please see response to BCUC IR 8.1.

16.1.1 Which methodology would Elenchus recommend?

RESPONSE:

Based on the evidence filed to date by FEI regarding the Tilbury Expansion project, Elenchus is not aware of any extraordinary circumstances that justify the exceptional treatment (ten year levelized margin) that is proposed. Absent additional information that demonstrates extraordinary circumstances that justify exceptional treatment, Elenchus would recommend using the standard rolled-in methodology.

See also the response to BCUC IR 8.1 and 8.1.1.

16.2 Please provide Elenchus' views as to the likely impact on the COSA results if FEI were to account for the Tilbury project in the recommended manner. Please provide quantitatively if possible.

RESPONSE:

Elenchus has found that due to the nature and complexity of COSA models, the only reliable method of determining the impact of any isolated change to one of these models is to produce a scenario that implements the change being contemplated. The only generalizable observation is the impacts are very often less significant that might be anticipated and even the directional impact can be surprising.

Elenchus is not prepared to speculate on the impact of alternate scenarios without implementing the alternate scenario in order to provide a definitive result.

Reference: Exhibit A2-2, page 26 and 27

5.4.4 Load Factor Adjustment

Rate Schedule 25 in Fort Nelson is intended to serve process load customers that have higher annual throughput and are less heat sensitive than large commercial customers. In its evidence for Fort Nelson, FEI states that customers with low factors below 40% are more heat sensitive than a typical process load customer and should be taking service under the large commercial rate. A 40% load factor has been used for RS 25 in the Fort Nelson COSA study in order to reflect the intended use of the rate schedule[1].

5.4.5 Elenchus Analysis of Fort Nelson Assumptions and Adjustments

Elenchus also supports the adjustments done to reflect how Fort Nelson is expected to operate in 2018. The test year used in a cost allocation study, based on Elenchus experience, reflects the normal operating conditions for a utility and known changes from past operations should be incorporated in the test year data as known adjustments.

17.1 How would the COSA results likely be impacted if FEI were to use actual average load factor rather than what the RS is 'intended' to serve?

RESPONSE:

Elenchus does not have the necessary data to be able to answer this question.

Also see the response to CEC 16.2.

[1] Exhibit B-1-1, Section 13.4.1.4, page 13-15, lines 23 to 29

17.2 Please provide Elenchus' views as whether it would be equally valid for FEI to use actual average load factors, or some other option for RS 25 in the Fort Nelson area. Please explain.

RESPONSE:

If two, or more, load factor options are under consideration and one of those options is considered more likely to occur than the other options(s) based on the best available information, Elenchus would not consider it to be equally valid to use a counter-factual forecast load factor rather than the expected load factor based on the best available evidence. In the absence of credible contrary evidence Elenchus considers it appropriate to use the expected forecast load factor, consistent with FEI's analysis of the expected new loads.

Reference: Exhibit A2-2, page 29

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.

Elenchus agrees with how FEI has calculated the revenue to cost ratios and margin to cost ratios results and agrees that no adjustment to rate classes' cost responsibility is required at this stage based on the R:C ratio range of reasonableness.

18.1 Does Elenchus believe that good (best available and most practically suitable) load and costing data are available and have been used by FEI?

RESPONSE:

Elenchus believes appropriate load and costing data has been used by FEI and is not aware of any better data that is available to FEI that could be used to improve the COSA significantly.

18.1.1 If no, please explain why not.

RESPONSE:

N/A.

18.2 Please confirm that the utility has experience and history using COSA studies in order to set rates.

RESPONSE:

It is Elenchus understanding that FEI is familiar and has used COSA studies in the past and that the COSA studies have been used to set rates.

In addition, Elenchus has reviewed the work of EES, FEI's consultant for this work, and has found the company's to be consistently competent and professional.

18.3 Please confirm that the BCUC has experience and history using COSA studies in order to set rates.

RESPONSE:

It is Elenchus understanding that BCUC is familiar with and has used COSA studies in the past and that the COSA studies have been used to set rates.

18.4 Please confirm that an R:C ratio of 1 would be indicative of an equal (50:50) probability that a rate class is contributing more or less revenue than its costs of service.

RESPONSE:

Elenchus does not view it as appropriate to interpret an R:C ratio in this way. Cost allocation is not a statistical exercise that has a probabilistic interpretation.

Given the imprecision of COSA models, which derives in part from the fact that there are multiple legitimate methods that can be used to allocate costs, each one producing a different R:C ratio, Elenchus is of the view that any R:C ratio that is within the defined range of reasonableness can be considered to be full cost recovery. An R:C ratio that is below the range is considered to indicate under-recovery of costs and any R:C ratio that is above the range indicates over-recovery of costs.

In a probabilistic situation, such as a sample survey, there is a true value that is being estimated. In the case of cost allocation there is no underlying true value that is being estimated. There are multiple possible ways of defining cost causality, each of which is equally valid, which implies that is a range of values that could each be considered to be the true value. In COSA work, rather than attempting to determine R:C ratios using multiple reasonable methods, a range of reasonableness is used.

18.4.1 If not confirmed, please explain why not.

RESPONSE:

See the response provided above.

18.4.2 Please confirm that as the R:C ratio moves away from unity, there is an increasing probability that the rate class is contributing either more or less revenue than its cost of service.

RESPONSE:

As long as the revenue to cost ratio for a rate class is within the acceptable range of values, (e.g. 0.90 to 1.10), it is considered that the class is paying its fair share of allocated costs.

18.4.2.1 If not confirmed, please explain why not.

RESPONSE:

Generally when conducting COSA studies, the goal is to achieve a revenue to cost ratio within the acceptable range, not to achieve a revenue to cost ratio of unity.

18.4.3 Please confirm that the probability that a rate class either is, or is not contributing more or less revenue than its cost of service increases as the revenue to cost ratio moves away from 1, until, at 1.05 or 1.1, whichever the threshold is, the probability is sufficient that Elenchus recommends that rebalancing should occur.

RESPONSE:

For the reasons outlined above, Elenchus does not consider it appropriate to view the R:C ratio through the probabilistic lens that is suggested by the question.

If the revenue to cost ratios are outside the acceptable range, Elenchus would recommend rebalancing.

18.4.4 Please confirm that a consistent R:C ratio above 1 for any rate class for a long period of time is indicative of that rate class consistently having a greater than 50:50 probability of contributing more revenues than its cost of service.

RESPONSE:

For the reasons outlined above, Elenchus does not consider it appropriate to view the R:C ratio through the probabilistic lens that is suggested by the question.

Generally when conducting COSA studies, the goal is to achieve a revenue to cost ratio within the acceptable range, not to achieve a revenue to cost ratio of unity.

18.5 Please confirm that a consistent R:C ratio below 1 for any rate class over a long period of time is indicative of that rate class consistently having a greater than 50:50 probability of contributing fewer revenues than its cost of service.

RESPONSE:

Please refer to the response to CEC 18.4.

18.6 Please confirm that periodic adjustment to a revenue to cost ratio of 1 for each rate class would not be inappropriate.

RESPONSE:

Please see response to CEC IR 1.1.

18.7 Please confirm that periodic (say every 5 or 10 years) adjustments of revenue to cost ratios to 1 for each rate class would not be inappropriate.

RESPONSE:

Please see response to CEC IR 1.1 and BCUC IR 1.1.