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May 24, 2017

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

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

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. (FEI) 2016 Rate Design Application - Project No. 3698899

We are counsel to the Commercial Energy Consumers Association of British Columbia (CEC). Attached please find the CEC's first set of Information Requests to Elenchus on the COSA Report with respect to the above-noted matter.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jj
cc: CEC
cc: FortisBC Energy Inc.
cc: Registered Interveners

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA

INFORMATION REQUEST #1 TO ELENCHUS ON THE COSA REPORT

FortisBC Energy Inc. 2016 Rate Design Application Project No. 3698899

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1. **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.

2. **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.

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

3. **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.

3.1.1. If not confirmed, please explain why not.

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.

4. **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 demands[8]. 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 OEB[9].

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

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.

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

6. **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'.

7. **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?

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

8. **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.

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

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.

9. **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 mains. 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.

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

10. **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.

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[21] Note that 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.

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

11. **Reference:** Exhibit A2-2 page 16

4.3.1 DEMAND RELATED

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*[24]. 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.

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

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

12. **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.

13. **Reference:** Exhibit A2-2, page 19 and page 22

4.5.1 TEST 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[29].

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[35]. There are also gas utilities in U.S. (e.g. Atmos Energy Corporation[36]) 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.

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

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

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

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.

14. **Reference:** Exhibit A2-2, page 20

4.5.6 BIOMETHANE CUSTOMERS

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[31]. 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[32]. 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.

15. **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[34].

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.

16. **Reference:** Exhibit A2-2, pages 21 and 22

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.
16.1.1. Which methodology would Elenchus recommend?
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.

17. **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[40].

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?
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.

18. **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?
  18.1.1. If no, please explain why not.
18.2. Please confirm that the utility has experience and history using COSA studies in order to set rates.
18.3. Please confirm that the BCUC has experience and history using COSA studies in order 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.
  18.4.1. If not confirmed, please explain why not.
  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.
    18.4.2.1. If not confirmed, please explain why not.
  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.

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.

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.

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

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.