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June 1, 2012

British Columbia Public Interest Advocacy Centre
Suite 209 – 1090 West Pender Street
Vancouver, BC
V6E 2N7

Attention: Ms. Leigha Worth, Acting Executive Director

Dear Ms. Worth:

Re: FortisBC Energy Utilities (comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy Inc. Fort Nelson Service Area ("FEFN" or "Fort Nelson"), FortisBC Energy (Vancouver Island) Inc. ("FEVI"), and FortisBC Energy (Whistler) Inc. ("FEW") Common Rates, Amalgamation and Rate Design Application (the Application)

Response to the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners Organization et al ("BCOAPO") Information Request ("IR") No. 1

In accordance with Commission Order No. G-46-12 setting out the Regulatory Timetable for review of the Application, the FEU respectfully submit the attached response to BCOAPO IR No. 1.

If there are any questions regarding the attached, please contact Paul Craig at 604-592-7459.

Yours very truly,

on behalf of the FortisBC Energy Utilities

Original signed:

Diane Roy

Attachment

cc (e-mail only): Registered Parties

1.0 Reference: Implementation of Amalgamation and Postage Stamp Rates

Exhibit B-3, Section 1.6, p. 5

Combining the Current Separate Gas Procurement Portfolios

1.1 Could the separate gas procurement portfolios proceed absent amalgamation? If so, why was this not done in the past?

Response:

The FEU have interpreted the first part of this question to be: "Could combining the separate gas procurement portfolios proceed absent amalgamation?"

Combining the separate gas procurement portfolios could proceed absent amalgamation. The FEU gas supply management and oversight of its gas portfolios was harmonized a number of years ago with the result that the separate gas portfolios are generally managed as if they were a single portfolio. However, the current, separate gas procurement portfolios for FEI and FEVI include certain key differences with respect to resource contracting. The main difference is that FEVI does not have access to Alberta supply and therefore does not hold any Alberta supply or storage resources nor does it hold NGTL or Foothills transmission capacity. FEI, on the other hand, has access to Alberta based resources through its Interior Transmission System, including the Southern Crossing Pipeline. This also provides FEI more flexibility to mitigate any surplus resources on a daily basis after customer loads are met.

Moving to a combined gas portfolio would notionally require purchasing and contracting gas supply resources reflecting the total combined load requirements of the FEU rather than purchasing and contracting for the resources based on the separate load requirements of FEI and FEVI. Such a combined portfolio could be comprised of a slightly different mix of resources than the FEU currently employ.

The main reason FEI and FEVI have continued to maintain separate gas portfolios has been to facilitate the separation of the gas costs; FEI and FEVI currently have different cost allocation and rate setting mechanisms for the determination of gas cost recovery rates. Additionally, the gas costs for FEVI had included a significant amount of offsetting revenue from the royalty rebate arrangement with the Province of B.C. which only expired at the end of 2011.

If legal amalgamation is not approved, maintaining separate gas portfolios would give FEVI more tools and flexibility to address its unique challenges, as discussed in the response to BCUC IR 1.46.1. This may include the use of different rate structures, different physical portfolio resources, and/or a separate hedging program and strategy.

1.2 Are there any expected material savings from combining the current separate gas procurement portfolios? If so, please provide an estimate of the annual savings.

Response:

The FEU do not expect any material cost savings from combining the current separate gas procurement portfolios.

As discussed in Section 7.4.3 of the Application, the benefits associated with the establishment of a single gas procurement portfolio will be derived from greater operational effectiveness, expanded contracting flexibility, and improved regulatory efficiency. Over the longer term, it is expected that the optimisation of a single portfolio may result in further savings that would not be realised through maintaining separate portfolios. The amount and materiality of these savings will depend on the availability of regional resources and their costs over time.

2.0 Reference: Common Rates of the Amalgamated Entity

Exhibit B-3, Section 1.7, p. 5

Exhibit B-3, Section 6.6, pp 122-124

Overall Savings from Amalgamation

The first referenced page indicates that (i) FEU's estimate of amalgamation costs is $2.0M and (ii) as a result of amalgamation, there will be a $2M reduction in the cost of service due to lower interest costs.

The second referenced section describes additional sources of amalgamation efficiencies that are expected to reduce costs.

2.1 Since there are expected savings in addition to the savings on interest charges – and the interest savings alone are expected to fully offset the costs of amalgamation – please confirm that the actual cost of service for the amalgamated utility will be less than the sum of the revenue requirements of the entities to be amalgamated. If unable to so confirm, please explain fully.

Response:

Confirmed. Please also see the response to BCUC IR 1.5.11.

3.0 Reference: Amalgamated Entity Rate Design

Exhibit B-3, Section 1.8, pp 6-7

Exhibit B-3, Appendix D-1, EES CoS Report, pp 13-15

Classification of Distribution Rate Base

The referenced exhibits indicate that distribution rate base was classified by using a Minimum System Study along with a Peak Load Carrying Capability adjustment. The second referenced exhibit states:

Generally, there are two methodologies that can be used to classify distribution costs: 100% demand and minimum system.

3.1 Does FEU agree that another method, namely the minimum-intercept (or zero-intercept) method can be used to classify distribution costs into demand costs and customer costs? If not, please explain fully.

Response:

Yes, the FEU agree that the zero-intercept method can be used to classify distribution costs. Please refer to the response to BCUC IR 1.134.1.

3.2 Please clarify whether the minimum-intercept approach was considered. If not, please explain why not; if so, please explain why it was rejected in favour of the Minimum System plus PLCC method.

Response:

Please refer to the response to BCUC IR 1.134.1.

3.3 Does FEU agree that for different customer classes, service mains costs, metering costs, and customer service requirements (and expectations) vary? If so, please explain how the EES Report recognizes and takes into account these differences; if not, please explain why not.

Response:

The FEU agree with the statement. The differences are reflected in the COSA Study where customers weighted for meters and services and customer accounting were used to allocate the costs for these three items. Please see pages 20-21 of the EES COS Report (Exhibit B-3, Appendix D-1) for a description of the weighting factors used.

4.0 Reference: Approvals Required to Amalgamate Under the UCA

Exhibit B-3, Section 2.1.1, p. 9

Amalgamating with THI

4.1 Please confirm that THI could have been removed from the ownership structure without amalgamating the subject utilities. If unable to so confirm, please explain.

Response:

As explained in Section 7.3 of the Application, the FEU propose to take advantage of the amalgamation of FEI, FEW, and FEVI to amalgamate THI as part of the amalgamation process in order to simplify the corporate ownership structure of the Amalgamated Entity. To amalgamate THI as part of the process proposed in this Application would have no impact on the Amalgamated Entity or its ratepayers. Furthermore, as explained in the Application, the amalgamation of FEI, FEW, and FEVI can proceed without amalgamating THI.

It is possible to restructure the ownership by removing THI without amalgamation. To do so, however, would require BCUC approval and would trigger costs, without material benefits. If the amalgamation of FEI, FEVI and FEW is not approved as proposed, the FEU have no plans at this time to remove THI from the ownership structure.

5.0 Reference: Common Rates Proposed

Exhibit B-3, Section 2.6, p. 15

The referenced exhibit states:

The common rates proposed for the Amalgamated Entity in this Application are based on the FEU's 2013 revenue requirements as applied for in the FEU's 2012-2013 RRA.

5.1 Please confirm that there are no differences between the total costs underpinning the 2012-2013 RRA and the total costs underpinning the instant proposal. If unable to so confirm, please provide an exhaustive list of deviations from the 2012-2013 proposal.

Response:

Confirmed. A difference does not exist between the stand-alone cost of service of each of the entities as applied for in the 2012-2013 RRA and this Application. However, as described in Sections 8.1 and 8.2 of the Application, there are amalgamation adjustments which impact the cost of service of the amalgamated utility.

6.0 Reference: Existing Rate Discrepancy

Exhibit B-3, Section 4.2 p. 72 and Appendix D-1, p. 5

Differentiating Among Customers

The referenced exhibits contain the following passage:

In reality, each customer on the system has a slightly different cost of service based on when they were connected, the location of the customer, the overall energy use, the load profile of the customer, etc. However, it would be impossible to set separate rates for each individual customer. For that reason customers are grouped into rate classes to reflect differences in usage patterns and connection costs. The question then becomes how far to carry the averaging of costs between customers on the basis of location. While there may be regional differences in costs, there are also differences in costs based on each customer's unique location on the system. We do not find it to be equitable to differentiate customer rates on the basis of broad regional differences while not differentiating on the basis of a more specific location or other factors.

6.1 Is there not currently a differentiation among customers based on location between those who are required to provide a contribution in order to be connected to the distribution system and those who are not so required?

Response:

Customers face a consistent policy on service line extensions in that FEI, FEVI and FEW customers all have a service line cost allowance ("SLCA") of $1,535 for dwellings other than duplexes and $3,070 for duplexes. Some customers will pay more to be connected to the system based on location and other considerations. Once connected, each customer pays the same rate as their applicable rate class as other customers in the same rate class in each service area.

Overall location, in terms of the FEI, FEVI, FEW and FEFN regions, is not a determining factor.

Specific location, as it relates to the proximity to the existing system, is one of many factors that go into the determination of whether or not a customer is required to make a contribution in aid of construction to connect to the distribution system. The length of the service line and the nature of the environment where the service line is to be installed are other considerations. For example, a customer with a proposed service line through rock and a well-established garden may pay more than a neighbor who has a proposed service line through an undeveloped yard with clay ground conditions

6.2 Are there any circumstances under which EES would recommend regional rates for a gas distribution utility? Please explain fully.

<u>Response:</u>

EES generally supports the use of postage stamp pricing. However, COSA methods, rates and pricing generally differ based on the specific circumstances of a particular utility. EES cannot determine whether regional rates would be appropriate on a generic basis, but would need to consider all of the relevant circumstances for a particular utility.

7.0 Reference: Unit Cost of Service and Revenue to Cost Ratio Comparisons

Exhibit B-3, Table 5-8, p. 100 and Table 5-9 p. 102

FEI Rate 1 Option D versus Option F

For Rate 1 FEI customers, in comparing Option D and Option F, the unit cost of service is higher under Option D (Table 5-8, $11.93 versus $11.90) while the revenue to cost ratio is lower under Option D (Table 5-9, 92.4% versus 93.4%).

7.1 Please confirm that the projected loads for each class are assumed to be the same in both tables. If unable to so confirm, please explain.

Response:

Confirmed.

7.2 Please explain why higher unit costs for the Rate 1 class in FEI correspond to a lower Revenue to Cost ratio.

Response:

When revenues are the same, having a higher cost will lead to a lower revenue to cost ratio. That is because customers are contributing a smaller portion to the assigned costs once the costs increase. For Options D and F the revenues are close but not the same because the midstream amounts, which are a pass-through, are different. Within Table 5-9 both the revenues and costs change in many of the cases and the differences in both the costs and revenues will contribute to differences in the revenue to cost ratios.

8.0 Reference: Customer Choice Extension to TEVI, FEW, and Fort Nelson

Exhibit B-3, Section 6.5.1, pp 117-119

Requirement to Amalgamate to Extend Customer Choice

8.1 Please explain why the Customer Choice Program could not have been extended to non-FEI customers prior to amalgamation.

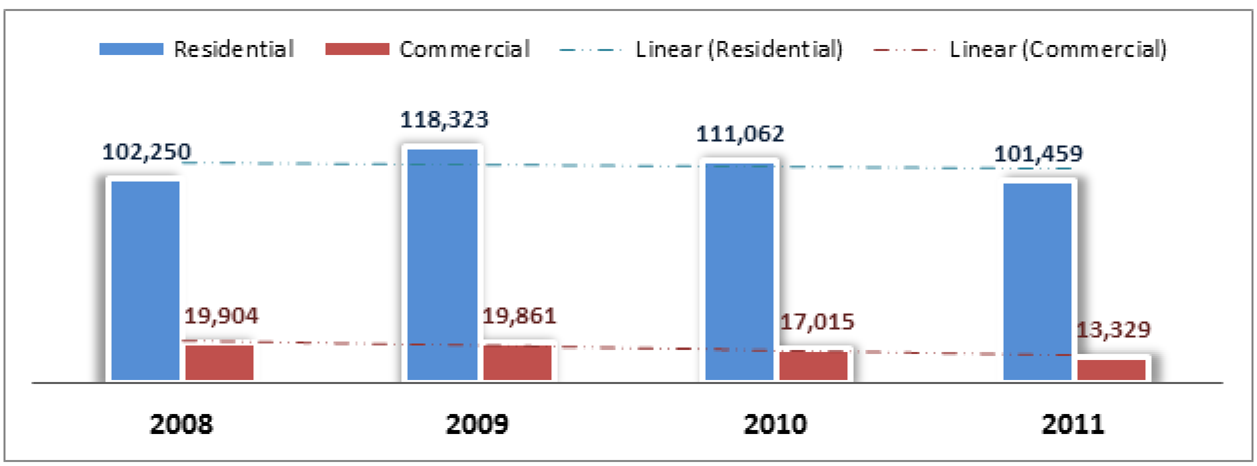
Response:

Please see the response to BCUC IR 1.39.1.

8.2 Please provide historical participation rates for FEI customers in the Customer Choice Program.

Response:

The historical participation rates for FEI customers in the Customer Choice Program are provided in the figure and table below.



Year	Rate 1	Rate 2&3	Total	Total Customers	% Participation
2008	102,250	19,904	122,154	827,911	15%
2009	118,323	19,861	138,184	832,989	17%
2010	111,062	17,015	128,077	839,898	15%
2011	101,459	13,329	114,788	845,291	14%

8.3 Does extension of the Customer Choice program pass a cost-benefit test?

<u>Response:</u>

No formal cost benefit test was conducted for the proposed extension of the Customer Choice Program to FEVI, FEFN and FEW. However, the FEU believe the extension of the program to FEVI, FEFN and FEW is the logical progression of the original effort to fulfill the 2002 BC Energy Plan.

Customer Choice is a government initiated program introduced in response to policy action 19 of the 2002 Energy Plan. The stated benefit was to facilitate competition for the supply of natural gas and to provide choice to those who wish to purchase their natural gas from a supplier other than FEI.

9.0 Reference: Ancillary Benefit of Reporting/Operational Efficiencies

Exhibit B-3, Section 6.6, pp 122-124

Quantification of Benefits

9.1 Please provide FEU's estimated annual savings under amalgamation for increased regulatory efficiencies and for increased legal efficiencies.

<u>Response:</u>

Sections 6.6.1 and 6.6.2 of the Application explain the potential regulatory and legal efficiencies resulting from amalgamation. With respect to regulatory efficiency, as explained in the Application, the total financial benefit for customers is difficult to quantify because the regulatory calendar for the Companies is a function of numerous variables, including the number of applications and complexity of the regulatory process. For reference, however, a major regulatory proceeding usually costs customers between $300 thousand to $1.5 million dollars in incremental costs that are usually captured in deferral accounts, in addition to internal labour devoted to the proceeding.

With respect to cost savings relating to legal efficiencies as a result of amalgamation, as explained in the Application, the amount is minimal. Currently, annual fees for maintaining the records, preparing the annual resolutions and annual report are about $300 per company. The fee to file the annual report is $45 for each company. Post amalgamation annual fees for the amalgamated company would be $300 and the filing fee for the annual report would remain at $45.