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May 8, 2018

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

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Inc. (FBC)

Project No. 1598939

2017 Cost of Service Analysis and Rate Design Application (the Application)

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

On December 22, 2017, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Exhibit A-6 amending the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact Corey Sinclair at (250) 469-8038.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

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

> In response to the Commission's report, on April 10, 2017 the Minister sent a letter to BC Hydro and FBC.[13] The Minister's letter referred to FBC's upcoming rate design application, asked FBC to take the "opportunity to examine a range of alternative rate designs with price signals for energy efficiency and electrification". The Minister's letter concludes as follows:
>
> > I encourage both BC Hydro and FortisBC to continue to engage with customers and build on the consultation from this process to make sure that the issues raised by customers inform future rate design applications. I also encourage you to consider how proposed rate structures will impact bills for customers choosing electric space and water heating and how this will affect utilities' opportunities for efficient electrifications.

1.1 Please provide a brief description of each of the alternative rate designs that FBC considered specifically with regard to 'energy and efficiency and electrification' and rejected, and explain why they were rejected.

Response:

As explained in Section 6.1.4 of the Application, the Company considered the following options for residential customers. FBC provides the following comments on the impact on the efficient use of the system and increased electrification by residential customers provided by these options:

- An option for stand-alone rate for customers without access to natural gas service: As explained in Section 6.1.4.1.1 of the Application, customers who advocate for a "no-gas" rate option indicate that environmental impact is an important consideration as this option would help with the continued use of electricity for their space heating and water heating needs (and hence improved electrification). However, the no-gas rate option has no cost basis (Section 6.1.4.1.1), would be difficult to administer and implement (Section 6.1.4.1.2) and will not encourage efficient use of the system (no incentive to shift consumption to off-peak period for example). Therefore, for the reasons explained in the Application, FBC did not propose a rate schedule that is only available to customers without access to natural gas service.

- Options of changing the existing RCR: As explained in Section 6.1.4.2 of the Application, FBC also considered making various changes to four key elements of the RCR (the Customer Charge, the Tier 1 and Tier 2 rates and the threshold). As their name implies, residential conservation rates are applied to conserve electricity usage, which is somewhat contrary to the purpose of electrification in the residential sector. For example, a customer that has maximized its electrification potential with electric space and water heating appliances, electric stove and electric vehicle can pay considerably

more than a customer who only uses electricity for non-heating purposes and therefore is charged under the first block rate. The RCR rates also do not necessarily promote the efficient use of the system as a low use customer can consume most of its energy during the peak time and still be charged under the first block while a high use customer who uses electricity in both off-peak and on-peak periods can be charged under the higher rate block.

FBC also considered declining block rates and changes to the Customer Charge in its residential rates modeling process, but decided to not pursue them due to various reasons.

FBC's proposed default flat rate structure can be considered to be a neutral option, meaning that although it does not necessarily encourage or discourage increased electrification, efficient use of the system and energy conservation, it does strike a balance among all of the conflicting qualities of the rate structures.

FBC's proposed optional TOU rates support both increased electrification and efficient use of the system as customers can benefit by increasing their electricity use during off-peak periods.

2. Reference: Exhibit B-1, page 31 and page 31

> As explained in the Commission consultant's report in FEI's 2016 rate design proceeding,[30] the increased share of fixed charges in fixed costs recovery is one of the trends that can be identified in recent utility rate design approaches which is designed to better align revenue recovery with cost causation (intra-rate class fairness) and mitigate the effects of disruptive technologies that may lead to cost recovery challenges from some customers. The Ontario Energy Board's (OEB) 2015 Board Policy (EB-2012-0410) regarding the new distribution rate design for residential electricity customers is one recent example. Under the OEB's new policy and by 2019, electricity distributors will structure residential rates so that all the costs for distribution service are collected through a fixed monthly charge[31]. The OEB policy explains that this new approach will enable residential customers to leverage new technologies such as roof-top solar and better understand the value of distribution service and provide greater revenue stability for distributors. The OEB policy also provides examples of other jurisdictions that have moved forward with fixed monthly distribution rates. Those jurisdictions include Ohio, which is implementing a fixed rate design for residential electricity customers, and Illinois, which has approved an increase in fixed charge rates for ComEd Illinois, with further increases expected.

> The 2017 RDA proposes changes to the rate structures of some classes in order to provide a consistent level of fixed cost recovery across the rate classes. Based on the extent to which existing rates recover the fixed customer and demand-related costs of service based on the unit costs contained in the COSA, FBC recommends a minimum fixed cost recovery of 55 percent of customer related unit costs and 65 percent of fixed infrastructure related unit costs. Certain rate classes are already at these levels and FBC is not proposing any decreases to those classes; therefore, the recommendation will impact some classes and not others. A minimum recovery of 55 percent and 65 percent respectively is in line with the fixed customer cost recovery already achieved by many of FBC's rate classes, and is not so high that other classes are impacted to a great degree. FBC believes it is a reasonable percentage to achieve.

2.1 Does FBC consider 55% as the optimal percentage for the minimum recovery of customer related unit costs? Please explain and provide the evidentiary basis.

Response:

Please refer to the response to BCUC IR 1.9.2.

2.1.1 If it is not the optimal percentage, please provide FBC's view of the optimal percentages and explain what considerations it is using to arrive at that conclusion.

Response:

Please refer to the response to BCUC IR 1.9.2.

2.1.2 If it is not the optimal percentage does FBC believe that it could migrate customers do a different percentage over a period of time? Please explain.

Response:

Please refer to the response to BCUC IR 1.9.2. If a different percentage were chosen that created more significant changes between the current and proposed rates, then some sort of transition or "migration" could be contemplated. The number of years over which such a transition would occur would depend on the magnitude of bill impacts for each class. Similar to the RCR transition that is proposed in the Application, FBC would endeavour to manage bill impacts such that customers would not experience rate shock over a short period of time. At 55 percent, the only class that has a pronounced difference between the current and proposed Customer Charge is RS 21. However, for this class the Customer Charge is not a significant factor in the overall billing as reflected in the bill impacts.

2.1.2.1 If yes, please discuss FBC's views of what appropriate migration might be, and what constraints there would be in doing so.

Response:

Please refer to the response to CEC IR 1.2.1.2.

2.2 Did FBC consider any percentages for minimum fixed cost recoveries of customer related unit costs other than 55%? Please explain.

Response:

Please refer to the response to BCUC IR 1.9.2 for a discussion of how the recovery percentages were arrived at.

2.2.1 If yes, please discuss the options and state why they were discarded.

Response:

Please refer to the response to BCUC IR 1.9.2 for a discussion of how the recovery percentages were arrived at.

2.2.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.9.2 for a discussion of how the recovery percentages were arrived at.

2.3 Does FBC consider 65% as the optimal percentage for the minimum recovery of fixed infrastructure related unit costs? Please explain.

Response:

Please refer to the response to BCUC IR 1.9.2 for a discussion of how the recovery percentages were arrived at. Both the Customer Charge percentage and Demand Charge percentage followed a similar approach. This approach yielded only one figure that was incorporated into the rate design.

2.3.1 If it is not the optimal percentage, please provide FBC's view of the optimal percentages and explain what considerations it is using to arrive at that conclusion.

Response:

Please refer to the response to CEC IR 1.2.3.

2.3.2 If it is not the optimal percentage does FBC believe that it could migrate customers do a different percentage over a period of time? Please explain.

Response:

Please refer to the response to CEC IR 1.2.3. Also, refer to the responses to CEC IRs 1.2.1.2 and 1.2.1.2.1 for a discussion of migration. The same general discussion applies here.

2.3.2.1 If yes, please discuss FBC's views of what appropriate migration might be, and what constraints there would be in doing so.

Response:

Please refer to the response to CEC IR 1.2.3.2.

2.4 Did FBC consider any percentages for minimum fixed cost recoveries other than 65% for fixed infrastructure related unit costs? Please explain.

Response:

Please refer to the response to CEC IR 1.2.2 with regard to Customer Cost recovery. The same general discussion applies here.

2.4.1 If yes, please discuss the options and state why they were discarded.

Response:

Please refer to the response to CEC IR 1.2.2 with regard to Customer Cost recovery. The same general discussion applies here.

2.4.2 If no, please explain why not.

Response:

Please refer to the response to CEC IR 1.2.2 with regard to Customer Cost recovery. The same general discussion applies here.

3. Reference: Exhibit B-1, page 32

> While in the 2017 RDA there is a directional move to better align rates with the COSA unit costs, and in particular to have the fixed charge rate components recover fixed costs more consistently, there are opposing views as to the appropriateness of shifting the burden of cost recovery between the fixed and volumetric charges within a rate. FBC seeks a better balance between the impacts of customer behaviour on their bills, such as through the opportunity to reduce bills by reducing consumption, and the recognition that the changing energy supply landscape can produce equity challenges between users of the utility system that may have very different requirements from the grid, both now and in the future.

3.1 FBC has outlined the reasons for shifting the burden of cost recovery between fixed and volumetric charges. Please outline the opposing concerns.

Response:

As explained in the Application, FBC believes that it is important to better align rates such that fixed charge rate components recover fixed costs more consistently. However, the opposing concerns with increasing the fixed charges and reducing volumetric charges are that such changes may be viewed as running counter to certain government energy policy considerations, such as the pursuit of energy conservation and efficiency. Lowering the energy charge may discourage customers' engagement in energy savings initiatives by reducing the bill savings that would otherwise be achieved by engaging in such initiatives. As such, a reasonable and appropriate balance needs to be achieved when it comes to shifting the burden of cost recovery between fixed and volumetric charges.

3.2 Please confirm that the Commission normally regulates rates on the basis of rate class and does not regulate rates on the basis of end-use.

Response:

Confirmed.

4. Reference: Exhibit B-1, page 32

> The increase in the Customer Charge to a minimum of 55 percent of the COSA customer-related unit cost, along with an increase in the demand-related charges in certain rate schedules, will help to mitigate the transfer of costs between customers on both an inter-class and intra-class basis. These changes are all part of the current Application, and if approved would function to stabilize revenues for FBC. However, all of these changes will be revenue neutral overall for the utility.

4.1 How will the increase in the Customer Charge and demand related charges in certain rate schedules help to mitigate the transfer of costs between customers on an inter-class basis. Please explain.

Response:

Please refer to the response to BCOAPO IR 1.4.3.

5. Reference: Net metering trend page 33

> As part of the due diligence related to confirming that the existing segmentation of customers still reflects the service characteristics of customers, FBC considered emerging trends in customer composition. The notable change in service to customers is the increasing participation in the Company's NM Program. This sub-group was examined within the COSA in order to assess whether the cost recovery attributes of this particular segment varied in a significant way from customers in general. The results indicate that NM customers have a lower load factor and R/C ratio than similar customers without NM systems.

5.1 Please provide quantitative evidence of the increasing participation in the Company's Net Metering program.

Response:

Please refer to the response to BCSEA IR 1.5.1.

5.2 Please discuss FBC's views as to the future of customer participation in FBC Net Metering and explain where FBC would expect participation to level off. Please provide FBC's forecasts quantitatively.

Response:

Customer participation has been trending upwards over the last few years. FBC assumes that this trend will continue and that net excess generation, while minor on an individual customer basis, will grow in the aggregate. While it is reasonable to assume that the growth rate will decline at some point as those customers with the means and desire to install net metered systems have done so, the changing economics of such installations may also impact the growth rate. FBC has not forecast distributed generation interconnections at this time.

5.3 Please provide the underlying reasons for why customers are increasing their participation in Net Metering.

Response:

Small-scale distributed generation technology is gaining traction with customers for a few reasons, including the perception that distributed generation is "greener" than utility generation, the desire to become more energy independent, and the perception that they are saving money.

5.4 What other emerging trends in customer composition did FBC identify? Please explain and provide quantitative evidence to support the trends.

Response:

Within the 2016 Long Term Electric Resource Plan (LTERP), FBC identified and discussed several emerging trends within Section 2.3: Customer Demand Environment. Furthermore, within Section 4: Load Scenarios of the LTERP, FBC quantitatively explored eight different load drivers:

1. Residential Rooftop Solar and Integrated PV Storage Systems;
2. Electric Vehicles;
3. Fuel Switching – Electricity to Gas;
4. Fuel Switching – Gas to Electricity;
5. Consistent and Persistent Weather Changes due to Climate Change;
6. Large Load Sector Transformation;
7. The Internet of Things (IoT); and
8. Combined heat and Power (CHP).

For quantitative evidence related to each of these load drivers, please refer to the Load Scenario Assessment completed by Navigant and included as Appendix G of the 2016 LTERP.

6. Reference: Exhibit B-1, page 34

> Given the small sample size and early stage of the NM Program, FBC is not seeking Commission approval of a new rate element such as a demand-related rate for NM customers at this time. FBC will continue to monitor and assess the impact that net metering has on other customers. As such, FBC provides this discussion only to increase understanding of the issues around increasing participation in net metering and one solution that could be adopted to address them.

6.1 Please provide a quantitative assessment of the impact that net metering has on other customers at this time.

Response:

As stated in the Application in Section 3.6, the NM customers have a lower R/C ratio and lower load factor than customers in general. However, due to the relatively low number of participants, when the customers are included in the class as a whole, the difference does not at this point change the R/C ratio of the class. The impact at this point is immaterial. However, the participation is increasing which may bring an increase in the impact as well. This is the reason that FBC included the discussion in the Application which indicates that this is a situation to be monitored.

6.2 How will FBC define the appropriate time to seek Commission approval of a new rate element such as a demand-related rate for NM customers? Please explain.

Response:

It is premature to provide a definitive response at this time. FBC will monitor its own customer situation, remain abreast of emerging industry trends and consider impacts to other customers. FBC included the NM discussion in the Application in order to make participants aware of the general issue of fixed cost recovery that NM may cause in the future.

6.3 Are existing and incoming NM customers made aware of the issue of cross-subsidization and the potential for new rate elements to emerge in the future? Please explain.

Response:

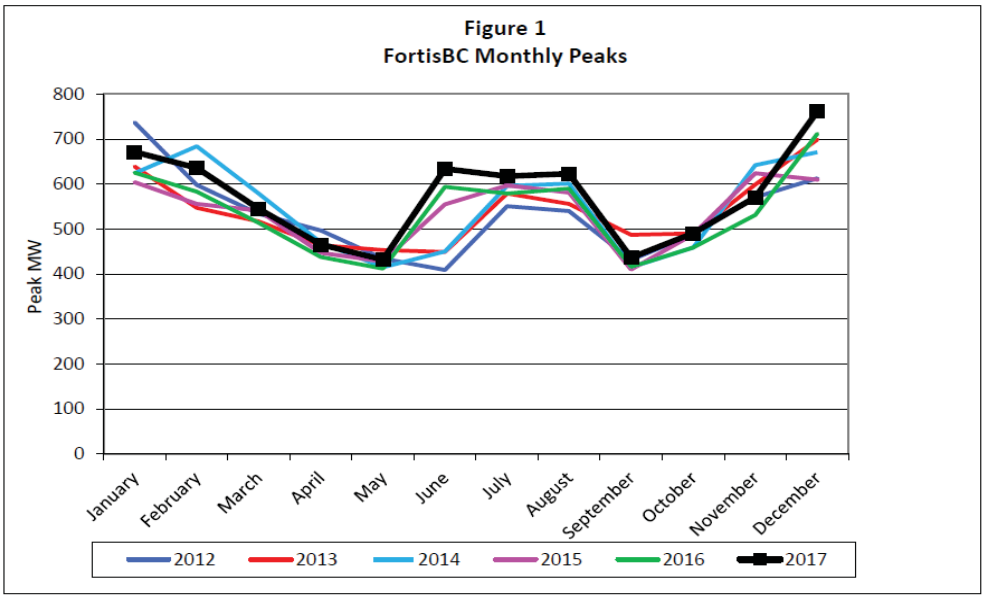
There has not been a discussion of the broader potential impact of NM included in customer discussions to this point. As participation rates increase across the utility industry, the issue is becoming a more common point of discussion at the utility level, but likely has not generally filtered down to customers. The examination of emerging trends and the development of appropriate charges is often approached in this manner. However, the discussion provided in the Application is an effort by FBC to bring the issue forward to promote awareness early on in its development.

6.4 What other solutions are potentially available to address the issue? Please explain.

Response:

If customers are to be afforded the opportunity to self-supply while remaining connected to the utility system for balancing and back-up supply, the appropriate solution is ultimately to have such a situation reflected properly in rates. FBC does not believe that other solutions are available that would be equitable to all customers.

7. Reference: Exhibit B-1, page 36



The final analysis was to look at the growth in the summer months relative to the growth in the winter months. When comparing the 2017 forecast peaks to 2009 actual peaks (the year of the last COSA), the summer peak is growing nearly twice as fast as the winter peak. For that time period, the total growth was 47 MW in the winter, or about 0.8 percent per year. For the summer peak, the growth was 73 MW, or about 1.5 percent per year. This indicates that the summer peak is moving closer to the level of the winter peak, and that FortisBC system planning will continue to need to recognize the growth in the summer peak.

7.1 When does FBC expect the summer peak to reach the winter peak, if ever? Please explain.

Response:

The Company consulted with EES to provide the following response.

FBC does not expect the summer peak to reach the winter peak within the 20-year planning horizon used for the LTERP. FBC's peak forecast is calculated by escalating the last ten years of peak data by the gross load growth rate and then taking the average. Based on 20 years of analysis completed for the Long Term Electric Resource Plan (LTERP) the winter and summer peaks are growing at an average rate of 0.8 percent and 1.5 percent respectively. Even though the summer peak is expected to increase at a faster rate than the winter peak, FBC does not anticipate it will pass the winter peak due to the fact that the winter peak is much larger than the summer peak. For 2035 the winter peak is forecast at 885 MW while the summer peak is forecast at 716 MW.

8. Reference: Exhibit B-1, page 45

> For comparison, in 2009 the total system energy was 3,107 GWh forecast for the year. The system energy change from 2009 to 2017 reflects an average annual increase of 0.7 percent per year. The number of customers, however, has increased by an average of 2.3 percent per year. The difference in the customer growth and energy sales growth is due in part to a change in the mix of customer types and the average use per customer. Wholesale sales also changed significantly (they decreased) due to the FBC purchase of the City of Kelowna electric utility.[38]

8.1 Does FBC expect the trend towards lower energy growth than customer growth to continue into the future? Please explain why or why not.

Response:

Confirmed. Generally, FBC does expect customer growth to exceed energy growth in the future. The majority of new customers added to the system on an annual basis are residential. These customers have relatively small energy loads, therefore increasing the customer count but not proportionally increasing the load. For example, one new residential customer addition contributed on average 11.27 MWh in 2016, which is equivalent to 0.0003 percent of the 2016 net load, while that same customer increased the 2016 customer count by 0.0007 percent.

If a new industrial customer was added to the system, such as a data mining operation, then the customer count would also increase by 0.0007 percent. The larger load could increase the annual demand by as much as 0.34 percent. This hypothetical industrial customer would therefore have a larger impact on demand than on customers. This impact could result in energy growth that exceeded customer growth. There are some customer additions that could have a more dramatic impact, such as a crypto-currency miner; however, such additions are unknown and cannot be included in any forecasts.

8.2 Please provide forecast growth rates for customers and energy sales for the next 5 years.

Response:

The requested energy sales, net of losses, is provided in the table below.

	Customers	Energy Sales
2018	0.6%	0.8%
2019	1.0%	0.4%
2020	1.1%	1.0%
2021	1.1%	0.6%
2022	1.1%	0.7%

9. Reference: Exhibit B-1, page 46 and page 48

Table 5-4: Functionalized Gross Plant Summary

Description	Cost Account(s)	Amount ($ millions)	Functionalized to:
Production	330-336	238.5	Production
Transmission	350-359	442.8	Transmission
Distribution	360-373	1,010.7	Distribution
General Plant[39]	389-397.1	251.2	28% Production 22% Transmission 50% Distribution
Total Gross Plant		**1,943.2**	

[39] General Plant is divided on the basis of labour (FTE) assigned to each of the three functions (production, transmission and distribution).

Table 5-6: Revenue requirement Functionalization Summary ($ millions)

Revenue Requirement Category	Total	Production	Transmission	Distribution
Production/Purchased Power	152.2	152.2		
Transmission O&M	18.3		18.3	
Distribution O&M	10.4			10.4
Customer Service/Accounts	6.5			6.5
Admin & General	13.0	3.6	2.8	6.5
Depreciation	(55.7)	(6.1)	(13.9)	(35.7)
Property Taxes	16.1	2.5	4.1	9.5
Return & Income Taxes	98.1	17.7	26.7	53.7
Other Revenues	9.5	2.1	1.6	5.7
Total	**360.7**	**179.9 (50%)**	**64.3 (18%)**	**116.5 (32%)**

9.1 Please discuss the types of costs included in 'General Plant'.

Response:

The Company consulted with EES to provide the following response.

General Plant includes any facilities that are not used exclusively for one of the three other functions (production, transmission, distribution), such as office buildings, vehicles, and computer equipment.

9.2 BC Hydro's Functionalization process apportioned costs between Generation, Transmission, Distribution and Customer Care. Please explain why FortisBC uses only Production, Transmission and Distribution and discuss the merits of each method.

Response:

The Company consulted with EES to provide the following response.

FBC does not use Customer Care as a separate function but rather treats it as a distribution function. This is consistent with the approach used in the 2009 COSA and accepted by the Commission at that time. This reflects an unbundling of costs into the three main functions for use in the event that customers have retail access and can purchase power supply from an alternate source. BC Hydro does not allow retail access, while FBC does allow retail access in limited circumstances (although no customer has ever been provided with retail access). In the case of retail access, the Customer Care component would remain with the distribution utility. Whether or not Customer Care is treated as a separate function, the costs would be classified and allocated on the basis of customers. The amounts allocated to each class and included in the customer-related unit cost would be the same regardless of whether that separate function was used.

9.3 Please identify any alternatives FBC considered for functionalizing General Plant, rather than on labour, and explain why FBC selected labour as the best methodology.

Response:

The Company consulted with EES to provide the following response.

FBC did not identify any alternatives. The use of labour ratios was the method approved by the Commission in the 2009 Rate Design Application and no changes in circumstances had occurred to warrant a change in the methodology.

9.4 The CEC interprets footnote 39 to mean that FBC functionalized General plant on the basis of the number of FTEs assigned to each area. Please confirm or otherwise correct.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

9.4.1 If confirmed, why did FBC use FTEs assigned to each area instead of labour $ values to functionalize General Plant?

Response:

The Company consulted with EES to provide the following response.

The number of FTEs was consistent with the approved methodology in the 2009 COSA and there were no changes in circumstances that would warrant a change in the method. Further, the number of FTEs was more readily available than the $ values, and it was not expected that the salaries on a per FTE basis were significantly different between the generation, transmission and distribution functions.

9.4.2 If confirmed, please recalculate the functionalization of General Plant based on labour $.

Response:

The following table compares the functional split for labour when labour $ are used rather than FTE. Note that the January-April 2017 period was used because that reflects the same timing as the FTE count. The resulting percent is compared to the percent based on FTEs. As the table shows, there is virtually no difference in the results. Therefore, there would be no change in the functionalization of General Plant.

	2017 January – April		
	Labour $	% Labour $	% FTE
Generation	$2,915,791	28.09%	28.06%
Transmission	$2,273,612	21.91%	21.92%
Distribution	$5,189,274	50.00%	50.02%
Total	$10,378,677	100.00%	100.00%

10. Reference: Exhibit B-1, page 47

5.1.2.1.2 **REVENUE REQUIREMENT**

The 2017 Revenue requirement was functionalized as described below:

- Hydraulic Production cost accounts (accounts 535-556), totaling $152.2 million were functionalized 100 percent to Production;
- Transmission cost accounts (accounts 560-567), totaling $18.3 million were functionalized 100 percent to Transmission;
- Distribution cost accounts (accounts 580-598), totaling $10.4 million were functionalized 100 percent to Distribution;
- Customer Service cost accounts (accounts 901-910), totaling $6.5 million were functionalized 100 percent to Distribution;
- Administrative & General cost accounts (accounts 920-933), totaling $13 million were functionalized on the basis of the labour breakdown associated with the three primary functions. This results in $3.6 million to Production, $2.8 million to Transmission, and $6.5 million to Distribution.
- Depreciation expense ($55.7 million) - split by functional areas. Generation depreciation follows generation and so on. Depreciation for General Plant and deferred charges follows the treatment of the General Plant, which in turn is based on the Gross Plant before General Plant. DSM amortization follows the DSM rate base account.
- Return ($87.2 million) and Income tax ($10.8 million) - functionalized on the same basis as the total rate base.
- Property taxes ($16.1 million) - related to the value of FBC's assets and are therefore treated in the same manner as the total system net plant.
- Other Revenues (a credit of $8.1 million) - revenues from other activities, such as pole attachment fees. Other revenues of FBC are treated as an offset to the Revenue requirement. Other revenues are therefore credited back to customer classes in a manner that is consistent with the specific other revenue line item.
- RS 37 Revenue (a credit of $1.4 million) – all customers on the system pay for the facilities used to provide this service. For the 2017 COSA FBC treats these revenues as an offset to the cost of service since the revenues provide a partial recovery to the fixed costs of the system. These revenues are allocated to the classes in proportion to the allocated rate base.

10.1 Please provide a brief discussion of the costs that are included in Administration and General costs.

Response:

The Company consulted with EES to provide the following response.

A&G costs include items such as human resources, information services, finance, regulatory costs and legal costs. These types of costs are there to support all three functions of the utility.

10.2 Please provide more detail as to how FBC functionalized the Administration and General costs on the basis of labour. Was this on the basis of FTEs or on the basis of labour cost?

Response:

The Company consulted with EES to provide the following response.

Costs were functionalized on the basis of FTEs.

10.3 Please describe the 'DSM rate base account' and how that is functionalized if at all.

Response:

The Company consulted with EES to provide the following response.

The DSM rate base amount is the deferred DSM costs that are included in Other Rate Base Items. The amount is functionalized as 72 percent production energy, 17 percent production demand and 12 percent transmission and distribution.

10.4 Does FBC functionalize DSM costs to its customers?

Response:

The Company consulted with EES to provide the following response.

There are no direct DSM expense items in the revenue requirement. However, expense items related to the DSM amount in the rate base (e.g. return and taxes) would be functionalized, classified and allocated to customers on the same basis as the DSM rate base.

10.4.1 If so, please explain why this is not included in the 2017 Revenue Requirement functionalization and where it is included?

Response:

Please refer to the response to CEC IR 1.10.4.

10.4.2 If no, please explain why not and explain why FBC functionalizes the DSM amortization.

Response:

The Company consulted with EES to provide the following response.

Not applicable.

10.5 Please describe how the 'total system net plant' is treated.

Response:

The Company consulted with EES to provide the following response.

The total system net plant is not treated in any specific manner in the COSA. Each rate base account has its own treatment in the COSA and the net plant amount is simply the sum of the amounts in all of those various accounts.

10.6 Please describe RS 37 service and customers.

Response:

RS 37 is Large Commercial Standby-Service for customers that normally serve a portion or all of their load through self-generation. Standby service provides such customers with access to utility supply in the case where the self-generation is unavailable. There is one customer taking service under Schedule 37. More details of the applicability of the rate can be found in FBC's tariff.

11. Reference: Exhibit B-1, Appendix A page 23

> FortisBC owns generation from four hydro-generation facilities collectively referred to as the Kootenay River Plants. Output from these plants is governed by a water coordination contract with BC Hydro, and other parties on the Kootenay River which predefines the amount of power that can be used at various times. Peak capacity forecast for December 2017 for the Kootenay River Plants is 208 MW, while the average energy expected from these plants is 180 MWa. Note that the measurement of MWa is based on the total MWh generated by the plant divided by the 8,760 hours in the years. This output reflects 47 percent of the 2009 energy requirement and 35 percent of the sum of the monthly capacity requirements. The remainder of FortisBC's power supply needs is met with power supply purchases.

> In the 1997 COSA, generation rate base was all considered to be energy-related. This ignores the fact that the output is available at the time of FortisBC's peak load and contributes to the capacity needed to serve loads. Because the Kootenay River Plants provide both capacity and energy to FortisBC, the 100% energy method was rejected in the 2009 COSA and it was determined that the generation rate base should be split between demand and energy for purposes of the COSA.

> Generation classification can be done using several different methods, most of which rely on looking at the use of various types of plants and their purpose within the system. For a utility with multiple generating plants it is common to look at the function of each plant in serving energy and demand needs, with some plants considered peaking units and others more related to providing energy. Sometimes the capital costs of a plant are considered demand-related and operating costs are considered energy-related, particularly for plants having significant fuel costs. Another approach is a peak credit method where the demand component is based on the cost of building a plant designed primarily to meet peak loads and any additional plant costs are deemed to be energy related. Other times the market based pricing of demand and energy components are used to develop the classification split.
>
> In the case of FortisBC, the Kootenay River Plants are the only utility-owned generation, and costs associated with the plants are a small percent of total power supply costs. This makes it difficult to use many of the standard classification methodologies and the small level of costs involved do not warrant a time-consuming or expensive study of the issue. On the other hand, BC Hydro does have a great deal of utility-owned generation and has had their classification of generation costs reviewed and approved through the regulatory process.

11.1 Does FBC consider 47% of the (2009) energy requirement and 35% of the sum of the monthly capacity requirements to be a 'small percentage' of its power supply? If so, please explain.

<u>Response:</u>

The Company consulted with EES to provide the following response.

FBC did not state that 47 percent of the (2009) energy requirement and 35 percent of the sum of the monthly capacity requirements was a 'small percentage' of its power supply. In the

reference above, the Company did state that the costs associated with the Kootenay River plants is a small percent of total supply costs. In terms of the output of the FBC resources compared to total power supply needs, the percent is not small. The statement was based on the actual production expense accounts in the revenue requirements. Total expenses for accounts 535 through 545 (production O&M accounts) amount to $13.6 million. In comparison to the total production cost (which includes purchased power) of $152.2 million, the amount is small.

11.2 What is the total value and the proportion of power supply costs contributed by Kootenay River Plants?

Response:

The Company consulted with EES to provide the following response.

The 2017 mid-year net book value of the Kootenay River Plants is $185.6 million.

The following table summarizes the various expense items from the 2017 COSA associated with the Kootenay River Plants:

	FBC Resource Expense
O&M	$13,555,250
Depreciation	$4,507,000
Return	$15,716,433
Taxes	$1,954,533
Total	**$35,733,215**
Total Production Expenses (without return, depreciation and taxes)	$152,159,234
Total Production Expenses (with return, depreciation and taxes)	$174,337,200
FBC Resource Cost as a Percent of Total Production Expenses	20.5%

The total costs for the FBC Kootenay River Plants are 20.5 percent of the total cost associated with power supply. Note that these costs exclude any assigned share of general plant or A&G costs.

11.3 Please provide an estimate of the cost to study the issue.

Response:

The Company consulted with EES to provide the following response.

Typically, a study related to generation would cost an amount ranging from $50 thousand to $100 thousand. That study would examine the use of the various production facilities of the utility and how that could be used to classify those costs between demand and energy. It would also calculate the costs of a new peaking plant and new baseload plant in order to arrive at a split that could be used under a peak credit method. The estimated cost excludes any regulatory costs associated with filing such a study with the Commission.

11.4 Why does 'small percentage' of total power supply costs mean that the standard classification methodologies are difficult to use?

Response:

The Company consulted with EES to provide the following response.

The small percentage of costs does not mean that standard methods are difficult to use. The small percentage of costs for FBC-owned generation means that the standard methods typically driven by types of generation plant would only apply to a small percentage of the costs. That would leave a large percentage of costs that could not be classified using standard methods. Also, the fact that FBC does not own multiple generating plants makes it difficult to use standard methods such as the base, intermediate, peak method where each generating unit is categorized by its main purpose.

11.5 Please elaborate on the potential for FBC to have used market supply costs for the classification split.

Response:

The Company consulted with EES to provide the following response.

EES would consider the approach used by FBC, with the BC Hydro Rate 3808 prices as a proxy to split costs into demand and energy components, to be a form of a market-based approach.

Market supply costs can be used as a proxy to split costs into further segments as well, where appropriate, though EES does not consider additional use of market supply costs beyond the extent to which already used in FBC's situation to be warranted. There are published prices (for example the Mid-C price) that show prices on a daily and on-peak off-peak period that could be used to split costs by period. Similarly, the market price of buying capacity only could be used as a proxy for the amount of power supply costs that should be applied as demand-related.

12. Reference: Exhibit B-1, appendix A page 23 and 24 and page 29

> To develop the classification split for FortisBC, the output from the Kootenay River plants was priced as if it were purchased at the BC Hydro 3808 rate to determine the equivalent split in costs between demand and energy. This split was then applied to actual costs of the Kootenay River plants for purposes of classification. The resulting split was roughly 20% demand-related and 80% energy-related. This approach was first used in the 2009 COSA and was accepted by the Commission.
>
> There were several factors considered when electing to use this proxy approach for classifying generation rate base for FortisBC. Despite some issues surrounding the derivation of Rate 3808, it does reflect the price paid by FortisBC for a large part of its power supply. To some extent FortisBC faces the decision to generate with its own hydro plants as opposed to purchasing from BC Hydro under the BC Hydro 3808 rate. And while theBC Hydro 3808 rate may not represent the best classification of costs from BC Hydro, it is what is in place today and is included in the rates of BC Hydro.
>
> There are two issues surrounding Rate 3808. As a result of concerns from the Commission, BC Hydro has been ordered to provide a more thorough analysis of generation plant classification in its next rate application. When this is completed FortisBC will re-examine its own classification method. Also, the pricing of Rate 3808 includes a transmission component. In theory, one would want to separate out just the generation component of Rate 3803 for use by FortisBC. However, in looking at the underlying classification of costs to the transmission class of BC Hydro, the generation split is equivalent to the 80% demand and 20% energy resulting from the full Rate 3808. So, while Rate 3808 may not fully match the results of the BC Hydro COSA, the net result is equivalent to the approach FortisBC would like to achieve for classification.

12.1 Please elaborate on how pricing the output from the Kootenay River plants as if it were purchased at the BC Hydro 3808 rate is used to determine the equivalent split in costs between demand and energy.

<u>Response:</u>

The Company consulted with EES to provide the following response.

For each month, the output from the Kootenay River Plants was priced at the BCH RS 3808 rates. For example, in January the capacity from the plants was 205 MW. This MW was multiplied by the BCH RS 3808 demand charge of $8,016 per MW to get a cost of $ $1.6 million. The energy from the plants was 142 GWh and this was then multiplied by the BCH RS 3808 energy rate of $46.99 per MWh to arrive at a cost of $6.7 million. This calculation was made for each month. When all months were summed together, the equivalent cost was $19 million of demand charges and $76.8 million of energy charges.

The resulting equivalent charges were equal to 20 percent demand-related and 80 percent energy related. This 20/80 split was applied to the rate base accounts associated with the

Kootenay River Plants. Any expenses items for the plants followed the split in the rate base for the plants.

12.1.1 Please provide the calculations demonstrating the 20% demand and 80% energy related costs or identify where they are included in the application.

Response:

The Company consulted with EES to provide the following response.

The calculation of the equivalent costs can be found in the Power Supply tab of the COSA model and is also shown in Schedule 5.3 of the COSA Report (Exhibit B-1, Appendix A).

12.2 Please provide FBC's views as to why using the BC Hydro 3808 rates as a proxy for generation rate base for the purposes of classification is preferable to using market rates. Please outline the advantages and disadvantage of using market prices instead.

Response:

The Company consulted with EES to provide the following response.

Please refer to the response to CEC IR 1.11.5. Use of BCH 3808 rates can itself be considered to be a form of market-based approach.

Market rates such as those rates published for the Mid-C trading hub, include daily and monthly prices but are only split between standard on-peak and off-peak periods. They do not provide demand charges or prices for capacity only purchases. That would limit the ability to allocate any costs from the Kootenay River Plants on the basis of demand.

FBC is not facing market prices in many hours of the year. In most cases, the BCH RS 3808 contract is the marginal resource for the utility. For that reason, the BCH contract is more specific to the circumstances of FBC and better reflects the market price facing FBC.

12.3 Does using BC Hydro 3808 rates as proxy for the Kootenay River plants cost theoretically result in BC Hydro's cost structure serving as a proxy for FortisBC's Kootenay River cost structure? Please explain.

Response:

The Company consulted with EES to provide the following response.

In a sense it may reflect elements of BC Hydro's costs, but only indirectly, in the sense that the price that actually faces FBC – which is the important consideration – presumably reflects in some respects the underlying cost of BCH resources.

12.4 From a general perspective, how would FBC view its cost structure relative to BC Hydro's cost structure. Please explain quantitatively.

Response:

The Company consulted with EES to provide the following response.

BC Hydro's cost structure for power supply is based on a larger mix of resources than FBC's and for that reason is more readily split between demand and energy components. FBC has several contractual resources that are not priced on demand and energy charges and are therefore hard to classify between demand and energy based on charges alone.

The BC Hydro treatment of power supply costs in setting rates is something that the Commission has ordered it to review in greater depth so it may by subject to change in the future. FBC will have to wait for any future review before determining whether it is appropriate to apply to FBC's power supply resources in the future.

With respect to the question more generally, FBC is uncertain as to what CEC considers the "cost structure" and therefore cannot quantify differences in the "cost structure".

13. Reference: Exhibit B-1, Appendix A page 26 and page 26 and page 27 and page 58

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the number of poles, conductors, and transformers in place at the utility is determined and separated by size. The cost associated with these facilities are then determined. Next, it is assumed that the actual numbers by size could be replaced by the minimum sized pole, conductor and transformer. The cost associated with the minimum size is then calculated.

The total costs of the minimum sized system are then compared to the cost of the as-built system to reflect the percent of costs attributed to the system that would be in place if all customers used a minimum amount of power. The remaining percent of costs is then attributed to the demand-related component.

- Substations, including land and station equipment. These costs are classified as demand-related as they are sized on the basis of the peak load for the area served.

- Poles, Towers & Fixtures. The results of the minimum system analysis are 81% customer-related and 19% demand-related. The customer-related costs are allocated on the basis of actual customers. The 2009 COSA split had a lower amount as demand-related at 96% customer-related and 4% demand-related. This difference is due to a larger number of more expensive poles in 2017 compared to 2009.

- Conductors & Devices. The results of the minimum system analysis are 65% customer-related and 35% demand-related. The customer-related costs are allocated on the basis of actual customers. The 2009 COSA split had a higher amount that was demand-related, at 58% customer-related and 42% demand-related.

- Line Transformers. The results of the minimum system analysis are 69% customer-related and 31% demand-related. The customer-related costs are allocated on the basis of actual customers. The 2009 COSA split was relatively comparable at 73% customer-related and 27% demand-related.

- Services, Meters and Installation on Customer Premises. These costs are all related to the customer component as they are installed for each customer served.

- Street Lights & Signal Systems. These costs are all directly related to the lighting class of customers and are directly assigned to that class.

When the minimum size was applied across all poles, the results showed a minimum system cost of $103.4 million compared to an installed cost of $131.4 million. This means that 81% of the costs were related to the minimum size pole, and were therefore classified as customer-related costs. The remaining 19% was classified as demand-related. This compares to a 96% customer/4% demand split resulting from the last minimum system study, which was conducted in 2007. This same split was used in the 2009 COSA.

13.1 Please confirm that substations, including land and station equipment are required as part of a minimum system.

Response:

The Company consulted with EES to provide the following response.

Substations are not necessarily required in the event that all facilities are built at a theoretical minimum size to serve customers with little or no load. Standard practice is to treat substations as 100 percent demand related as they are driven by peak loads rather than the number of customers on the system.

13.2 If so, could FBC provide a minimum system cost for these items to be classified as customer? Please explain why or why not.

Response:

Not applicable. Please refer to the response to CEC IR 1.13.1.

13.3 Please provide FBC's views as to why there is a shift towards 'more expensive' poles

Response:

The data utilized in the last minimum system study indicated that the total installed cost of three-phase poles was approximately 4 percent higher than their single-phase equivalents. Updated 2017 estimating data indicated that the total installed cost of these three-phase structures is approximately 21 percent higher than their single-phase equivalents. This change is due in part

to changes in material and construction standards, and is also due to more accurate estimating of the additional labour and material required to frame these three-phase structures.

14. Reference: Exhibit B-1 Appendix A page 27

> While the minimum system is, in theory, designed to carry only a minimal amount of load, the actual facilities designated as the minimal size are actually capable of carrying some amount of demand, therefore overstating the level of the customer-related component. The actual amount of demand capability within the minimum system is a function of load density, minimum required clearances, minimum equipment standards, temperature, and other engineering considerations. Under traditional cost allocation techniques, each customer/connection attracts an equal allocation of the minimum system, plus each customer class is allocated demand costs based on the total customer class' non-coincident peaks. As such, it has been argued that a customer class' non-coincident demand allocator is too large, because a portion of these peak demand-related costs are being covered through the per customer/connection minimum system allocation.
>
> The correction of the problem of over allocating demand can be achieved by the application of a PLCC adjustment. This adjustment was first introduced in the 2009 COSA. The precise amount of a PLCC adjustment should match the definition of the minimum system adopted. In the FortisBC case, it was determined that the average PLCC for the FortisBC system is 1.09 kW per customer. Appendix B provides a more detailed discussion of the PLCC and how the amount was calculated.
>
> The PLCC adjustment will determine how much demand for a customer class can be met by the minimum system (number of customers/connections x PLCC for minimum system) and will credit this amount against the classification's non-coincident peak demands used for determining demand allocators. The adjusted customer class' non-coincident peaks can then be used to allocate the distribution demand-related costs, eliminating the double-counting. The number of customers/connections used for the PLCC should match the number of

14.1 Please explain why the traditional cost of service allocation is based on non-coincident peaks versus some form of coincident peak?

<u>Response:</u>

The Company consulted with EES to provide the following response.

For distribution facilities, planning is done by looking at the potential for peak load for each customer, regardless of when it occurs. For example, a transformer must be able to handle the local peak demand for a small group of customers, irrespective of when that peak occurs or what is occurring in any other local area. For that reason, it is just the local demand that is used for planning, and that local demand is best represented by the non-coincident peak.

15. Reference: Exhibit B-1, Appendix A page 29

To reflect the fact that these purchases work together to provide the power needed to FortisBC, it was determined that the BC Hydro 3808 rate breakdown of demand and energy prices could be used as a proxy for the split between demand and energy components, as used for FortisBC's own generation. The output from these projects were priced at BC Hydro 3808 rate on a monthly basis to determine the equivalent split in costs between demand and energy. This split was then applied to actual costs of the projects for purposes of classification. The resulting split was roughly 31% demand-related and 69% energy-related.

FortisBC purchases power from BC Hydro under a contract for up to 200 MW of power, with prices set under the BC Hydro 3808 rate. The rate for this power for 2017 is equal to $8.016 for January through March and $8.297 per kW-month for the remaining months. The 2017 energy rate is 4.699 cents per kWh for January through March and 4.863 cents per kWh for the remaining months. Because there are separate demand and energy charges associated with this purchase, those respective charges are classified as demand-related and energy-related in the COSA.

The remaining power requirements for FortisBC are met using various market purchases, and in some cases there are surplus quantities sold as well to match the hourly needs of the utility. Market purchases include 32 to 43 MW blocks in the winter months. These purchases were classified as energy-related as they were assumed to provide 0 capacity. Net impacts of market purchases and sales are less approximately $6 million for 2017.

Table 7 summarizes the output and costs associated with each of the power supply sources:

Table 7
Power Production Cost Detail

	Capacity (MW)	Average Energy (MWa)	2017 Costs (Millions)
Kootenay River Plants	208	182	$16.0
Brilliant Hydro	205	113	$42.7
BCH 3808 Purchases	176	86	$49.0
Waneta Expansion	87	0	$38.3
Net Market Purchases	0	25	$6.2
Total System	734	406	$152.2

15.1 Would FBC agree that the BC Hydro 3808 purchases likely have a significantly different cost structure from the Kootenay River Plants in that it provides significantly less capacity and less than half the energy for triple the cost? Please explain why or why not.

Response:

No, FBC does not agree with the proposition set out in the question. FBC assumes that the cost structure referred to is the price for capacity and energy for the BC Hydro 3808 purchases.

This is only used as a proxy to split the Kootenay River Plants costs into energy and capacity components and the relative magnitude of the costs themselves are not a factor. While the exact split between energy and capacity costs for the Kootenay River Plants is not known, using BC Hydro 3808 as a guide is a reasonable approximation.

15.2 Please justify the assumption that market purchases provide 0 capacity.

Response:

The Company consulted with EES to provide the following response.

EES was correct that the purchases classified as energy-related did not provide any capacity. This is not to say that market purchases can never provide capacity, but the market purchases included as part of the analysis did not provide any capacity since they were not on peak hours.

16. Reference: Exhibit B-1, Appendix A page 32 and page 33 and page 35

- *2 Critical Coincident Peaks (2 CP).* Coincident peaks are typically used for allocating a portion of production costs and all of transmission costs as they are generally sized for the system peak as a whole. For FortisBC, it was determined that the sum of the 2 highest summer and 2 highest winter coincident peaks were the most appropriate to reflect critical period system use and planning for facilities, as explained further below. This is consistent with the peak allocation method used in the 2009 COSA. The 2 CP allocator was used for generation and transmission rate base accounts. Note that while 4 months of data were used to develop the 2 CP number, it is not to be confused with the 4 CP method used by BC Hydro using the 4 highest peaks of the year. The 2 CP term was used historically and represents the dual winter/summer peak of the utility.

Given historical FERC cases, using an allocation other than 12 CP is supported if the equation above results in a value greater than 20%. A smaller value supports using 12 CP. It is not clear how many peak months should be included in the calculation. In the past, three, four or six months have been included as the peak period.

Table 8
FERC and OEB Tests for Demand Allocator

Test	C2012	C2013	C2014	C2015	C2016	C2017 Forecast
FERC Tests						
#1	12CP	12 CP	1CP or 4CP	12CP	12 CP	12CP
#2	1CP or 4CP	1CP or 4CP	1CP or 4CP	12 CP	1CP or 4CP	1CP or 4CP
#3	Does not exceed (1CP or 4CP)	Does not exceed (1CP or 4CP)	Does not exceed (1CP or 4CP)	Does not exceed (1CP or 4CP)	Does not exceed (1CP or 4CP)	Does not exceed (1CP or 4CP)
#4	1CP or 4CP	1CP or 4CP	1CP or 4CP	12 CP	1CP or 4CP	1CP or 4CP
OEB Tests						
#1	Use CP Test #2	Use CP Test #2	Use CP Test #2	12 CP	Use CP Test #2	Use CP Test #2
#2	4CP	4CP	4CP	NA	4CP	4CP

16.1 Please confirm that FBC considers itself to be a winter and summer peaking utility.

Response:

The Company consulted with EES to provide the following response.

Confirmed.

16.1.1 If confirmed, are there other instances, other than cost of service allocations, for which this designation is utilized? Please explain.

Response:

The Company consulted with EES to provide the following response.

While it may not be actually used as a designation, the winter and summer peaks would both be used when forecasting future loads, when planning for power supply, when planning for transmission and distribution facilities and for setting the proposed TOU rates.

16.2 How did FBC determine that 4 months was the appropriate number of months to be included in the data? Please explain.

Response:

The Company consulted with EES to provide the following response.

The selection of four months was determined by looking at the actual load data over time. In most years, the two highest winter and two highest summer peaks are the most pronounced peaks.

16.3 Did FBC conduct the tests using differing numbers of months to be included in the calculation?

Response:

The Company consulted with EES to provide the following response.

The tests rely on data for all 12 months in making the determinations as to the appropriate allocator so FBC did not use differing numbers of months in the calculations.

Please refer to the discussion included in the responses to BCUC IRs 1.30.1 to 1.30.5 for more information on the selection of the 2 CP allocator for FBC.

16.3.1 If yes, please provide the results.

Response:

The Company consulted with EES to provide the following response.

Not applicable. Please refer to the response to CEC IR 1.16.3.

16.3.2 If no, please explain why not.

Response:

Please refer to the response to CEC IR 1.16.3.

17. Reference: Exhibit B-1, Appendix A page 36

> The demand allocation method was selected after consideration of past precedent, FERC and OEB tests, comparisons of load shapes and growth of winter and summer peaks. The 12CP approach was rejected as FortisBC does not have a flat load shape over the year. The 2 CP approach was selected rather than a 1 CP or 4CP approach because FortisBC has a significant summer peak. While the summer peak is not at the same level as the winter peak, it is growing faster than the winter peak and will increasingly have a larger impact on the system.

17.1 Are there other utilities with similar consumption patterns as FBC that FBC is aware of?

Response:

Please refer to the response to BCUC IR 1.25.1.

17.1.1 If so, please identify.

Response:

Please refer to the response to BCUC IR 1.25.1.

17.2 Is FBC aware of any other utilities that use a 2CP allocator?

Response:

The Company consulted with EES to provide the following response.

FBC is not aware of another such utility. Please refer to the response to BCUC IR 1.25.1 for a discussion of why 2 CP remains the appropriate allocator for FBC.

17.2.1 If so, please provide a list of other that utilities utilize a 2CP allocator.

Response:

Not applicable. Please refer to the response to CEC IR 1.17.2.

18. Reference: Exhibit B-1, Appendix A page 52

Table 15 Comparison of Residential Rate Charges	
Utility	**Basic Charge per Month**
BC Hydro	$5.78
Manitoba Hydro	$7.28
Nova Scotia Power	$10.83
Hydro Quebec	$12.36
ATCO Electric Yukon	$14.65
Newfoundland Power	$16.04
FortisBC	$16.05
New Brunswick Power	$21.60
SaskPower	$22.01
Fortis Alberta	$23.05
ATCO Electric Alberta	$38.59

For small commercial customers, the customer charge ranged from $0 per month for New Brunswick Power and ATCO Electric Yukon to a high of $62.80 for SaskPower. The majority were in the range of $15 to $30 per month range. However, utilities without a fixed charge tended to have a demand based contract minimum amount.

18.1 Please provide the Commercial rates broken down by utility as was done in Table 15 for Residential rates.

Response:

The Company consulted with EES to provide the following response.

A table showing the basic charge by month for commercial customers can be found in Appendix D of the Cost of Service Study (Exhibit B-1, Appendix A, page 283 of the Application pdf).

19. Reference: Exhibit B-1, Appendix A page 53

Rate Base

The total rate base of $1.28 billion has been classified into various components and allocated to customer classes as found in 4.3 of Appendix A. The split by customer class can be summarized as follows:

	Millions
Residential	$ 733.6
Other Retail	396.0
Wholesale	154.9
Total System	$1,284.5

This amounts to an assignment of 57% to the residential class, 31% to other retail classes and 12% to wholesale customers.

Revenue Requirement

The total revenue requirement of $360.7 million has been classified into various components and allocated to customer classes as found in Schedule 3.3 of Appendix A. The results are summarized as follows:

	Millions
Residential	$188.2
Other Retail	122.1
Wholesale	50.4
Total System	$360.7

This amounts to an assignment of 52% to the residential class, 34% to other retail classes and 14% to wholesale customers.

The allocated revenue requirement can be compared to the following projections of revenue for 2017:

	Millions
Residential	$185.1
Other Retail	126.3
Wholesale	49.2
Total System	$360.5

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19.1 Please confirm that the information presented above may be considered the best information that FBC is reasonably able to attain.

Response:

The information that the COSA was based on was the most recently approved revenue requirements available at the time it was completed. On that basis, this statement is confirmed.

19.2 Please confirm that the information presented above may be considered equivalent or better in quality relative to the information provided in other jurisdictions.

Response:

The Company consulted with EES to provide the following response.

FBC has not reviewed the quality of the COSA filings in all other jurisdictions and while it followed generally accepted methodologies, there are some jurisdictions in which the methodologies used are not exactly the same as the generally accepted ones used for FBC. Since these are generally accepted methodologies it would be expected that, in general, the FBC results would have similar quality to other COSA results where generally accepted methodologies were followed.

19.3 Please provide the historical revenue requirement and allocated revenue requirement for each rate class over the last 20 years.

Response:

The requested information is not available without completing separate Cost of Service Analyses for each of the last 20 years. FBC has provided the requested information for those years within the prior 20 years where a COSA was completed (1997 and 2009) and included results from the 2017 COSA for comparison.

Table 1: Allocated Revenue Requirements by Rate Class for 1997, 2009 and 2017 COSAs

	1997[1,2]	2009[3]	2017[4]
Residential	$43,326,840	$114,220,730	$188,215,388
Small General Service (Small Commercial)	n/a	$16,684,509	$33,555,412

	1997[1,2]	2009[3]	2017[4]
General Service (Commercial)	$16,103,800	$32,386,980	$50,592,085
Large General Service (Primary)	$5,345,772	$8,674,159	$24,783,364
Large General Service (Transmission)	$1,721,645	$4,839,581	$6,627,451
Wholesale (Primary)	$21,753,449	$47,252,720	$44,238,404
Wholesale (Transmission)	$1,773,267	$5,949,276	$6,153,896
Lighting	$978,384	$2,355,098	$3,116,434
Irrigation	$1,330,843	$3,063,706	$3,396,465
Total Allocated Revenue Requirements	**$92,334,000**	**$235,426,757**	**$360,678,900**

[1] West Kootenay Power Rate Design and New Service Options Application, dated September 2, 1997.
[2] The 1997 COSA included Small General Service in the General Service Rate Class.
[3] As filed in the November 19, 2010 Compliance Filing to Order G-156-10.
[4] Schedule 1.1, Appendix A to Appendix A of 2017 COSA and RDA (Exhibit B-1).

Table 2: Percentage of Total Allocated Revenue Requirements by Rate Class for 1997, 2009 and 2017 COSAs

	1997[5]	2009	2017
Residential	46.9%	48.5%	52.2%
Small General Service (Small Commercial)	n/a	7.1%	9.3%
General Service (Commercial)	17.4%	13.7%	14.0%
Large General Service (Primary)	5.8%	3.7%	6.9%
Large General Service (Transmission)	1.9%	2.1%	1.8%
Wholesale (Primary)	23.6%	20.1%	12.3%
Wholesale (Transmission)	1.9%	2.5%	1.7%
Lighting	1.1%	1.0%	0.9%
Irrigation	1.4%	1.3%	0.9%

[5] The 1997 COSA included Small General Service in the General Service Rate Class.

19.4 Please provide the Rate base broken down by rate class for the last 20 years.

Response:

The requested information is not available without completing separate Cost of Service Analyses for each of the last 20 years. FBC has provided the requested information for those years within the prior 20 years where a COSA was completed (1997 and 2009), and included the results from the 2017 COSA for comparison.

Table 1: Allocated Rate Base by Rate Class for 1997, 2009 and 2017 COSAs

	1997[1,2]	2009[3]	2017[4]
Residential	$122,517,287	$463,667,611	$733,572,486
Small General Service (Small Commercial)	n/a	$67,689,578	$120,795,391
General Service (Commercial)[1]	$45,600,895	$122,456,474	$157,310,589
Large General Service (Primary)	$12,293,659	$30,655,084	$73,703,544
Large General Service (Transmission)	$3,319,741	$16,192,225	$16,403,447
Wholesale (Primary)	$46,232,032	$164,659,181	$139,876,791
Wholesale (Transmission)	$3,164,865	$19,147,846	$15,050,920
Lighting	$2,362,617	$11,408,634	$15,991,978
Irrigation	$4,120,318	$12,101,867	$11,817,855
Total Allocated Rate Base	**$239,611,414**	**$907,978,500**	**$1,284,523,000**

[1] West Kootenay Power Rate Design and New Service Options Application, dated September 2, 1997.
[2] The 1997 COSA included Small General Service in the General Service Rate Class.
[3] As filed in the November 19, 2010 Compliance Filing to Order G-156-10.
[4] Schedule 1.5, Appendix A to Appendix A of 2017 COSA and RDA (Exhibit B-1).

Table 2: Percentage of Total Allocated Rate Base by Rate Class for 1997, 2009 and 2017 COSAs

	1997[5]	2009	2017
Residential	51.1%	51.1%	57.1%
Small General Service (Small Commercial)	n/a	7.5%	9.4%
General Service (Commercial)[1]	19.0%	13.5%	12.3%
Large General Service (Primary)	5.1%	3.4%	5.7%
Large General Service (Transmission)	1.4%	1.8%	1.3%
Wholesale (Primary)	19.3%	18.0%	10.9%
Wholesale (Transmission)	1.3%	2.1%	1.2%
Lighting	1.0%	1.3%	1.2%
Irrigation	1.7%	1.3%	0.9%

[5] The 1997 COSA included Small General Service in the General Service Rate Class.

20. Reference: Exhibit B-1, Appendix A page 54

Revenue to Cost Ratios

A summary comparison of the revenues at present rates, allocated cost of service and resulting revenue to cost ratios can be found in Schedule 1.1 of Appendix A. The resulting revenue to cost ratios are shown in Table 16:

Table 16
COSA Revenue to Cost Ratios

	Revenue to Cost Ratio
Residential	98.4%
Small Commercial 20	102.2%
Commercial 21/22	104.7%
Large Commercial Primary 30/32	104.0%
Large Commercial Transmission 31	107.0%
Lighting	92.2%
Irrigation	97.2%
Wholesale Primary 40	96.7%
Wholesale Transmission 41	103.9%
Total	100.0%

The proposed range of reasonableness of 95 to 105 percent is proposed in this application, which is consistent with the last COSA and resulting Order. The majority of rate classes fall within this range and therefore do not need rebalancing. The large commercial (Rate 31) has a RC ratio above the range while the Lighting class has an RC ratio below the range. It would be appropriate to rebalance these two classes to move towards the COSA results.

The revenue to cost ratios and unit costs resulting from the COSA were used as inputs in developing the rates proposed in the Rate Design Application. The rate design for several of the classes are adjusted to better meet goals of the utility. The mechanism for rate rebalancing between classes is also described in the Rate Design Application and relies upon the revenue to cost ratios in the COSA.

20.1 Please provide the historical revenue to cost ratio results for the last 20 years.

Response:

The requested information is not available without completing separate Cost of Service Analyses for each of the last 20 years. FBC has provided the R/C ratios included in the COSA studies for those years within the prior 20 years where a COSA was completed (1997 and 2009) and included the 2017 R/C Ratios for comparison.

Table 1: R/C Ratio by Rate Class for 1997, 2009 and 2017 COSAs

	1997[1,2]	2009[3]	2017
Residential	90.1%	93.3%	98.4%
Small General Service (Small Commercial)	n/a	107.6%	102.2%

	1997[1,2]	2009[3]	2017
General Service (Commercial)[1]	111.6%	128.2%	104.7%
Large General Service (Primary)	114.5%	112.8%	104.0%
Large General Service (Transmission)	125.3%	98.7%	107.0%
Wholesale (Primary)	101.2%	94.0%	96.7%
Wholesale (Transmission)	116.7%	95.1%	103.9%
Lighting	109.1%	84.4%	92.2%
Irrigation	75.8%	88.8%	97.2%

[1] The 1997 COSA R/C Ratios included Small General Service in the General Service Rate Class.

[2] The 1997 COSA R/C Ratios shown are Year 0 (before rebalancing) as filed in the West Kootenay Power Rate Design and New Service Options Application, dated September 2, 1997.

[3] The 2009 COSA R/C Ratios shown are the Year 0 (Initial before rebalancing) as filed in the November 19, 2010 Compliance Filing to Order G-156-10.

21. Reference: Exhibit B-1, page 55

> As informed by past practice and prior Commission proceedings described later in this section, FBC believes that the appropriate RoR for evaluating its R/C ratios is 95 per cent to 105 per cent. An R/C ratio falling within the 95 percent to 105 percent RoR indicates that the revenues recovered from customers on that rate schedule are adequately recovering the allocated cost to serve them.

21.1 Please provide FBC's reasons for utilizing a 'Range of Reasonableness' as opposed to simply utilizing the R:C ratios in its determinations as to the appropriateness of rebalancing.

Response:

FBC believes that a Range of Reasonableness (RoR) is required because the numerous assumptions, estimations, simplifications, judgements and generalizations in the COSA study make the R:C ratios uncertain. Therefore, a ROR for the R/C ratio has been consistently used by the Commission in the past rate designs and is in line with the industry and FBC's past practice.

21.2 Please provide a jurisdictional review of the 'range of reasonableness' for other electric utilities in Canada and the US.

Response:

The Company consulted with EES to provide the following response.

EES did not complete a review of the RoR in its original jurisdictional review. The EES review used the jurisdictional review in the BC Hydro 2015 RDA as one source and their review lists a RoR of 95 to 105 percent for Manitoba Hydro and Puget Sound Energy, a range of 90 to 110 percent for Newfoundland Power, and a target of 100 percent for Idaho Power and Portland General Electric. To complete this response EES looked at the recent Decisions and Applications for the remaining utilities in its own jurisdictional review. For Atco Electric the Commission's Decision discusses a desired 95 to 105 percent range. For Fortis Alberta no particular RoR was provided. For Nova Scotia the Decision reviewed was exclusive to the COSA and did not discuss the RoR in setting rates; however, in another case we are aware of it stated that a 95 to 105 percent range was established by the Board. The New Brunswick application discusses a 95 to 105 percent range, and included the following footnote:

> The PUB decision (April 15, 1992, page 26) states "A target of 1 to 1 is impossible to achieve in light of the ongoing changes in costs and revenues and the inherent inaccuracies in any cost of service study. The Board considers that a long term target range of .95 and 1.05 for revenue to cost ratios is reasonable". The PUB maintained this view in their 2005 decision (December 21, 2005, page 38) which states "We are of the view that a long term target range of .95 to 1.05 for the revenue to cost ratio for each class is reasonable. The Board recognizes that rate impact considerations will require that some classes be moved gradually to or within this range."
>
> The above noted target range continues to be viewed as a reasonable range by the EUB. The EUB's decision (May 13, 2016, page 2) states "In theory, a revenue to cost ratio of 1.0 should apply for each class. There may be valid reasons, however, why rates will produce projected revenues higher than allocated costs for some classes, offset by rates for other classes that will produce revenues lower than allocated costs. In the decision of December 21, 2005, the New Brunswick Board of Commissioners of Public Utilities (PUB) indicated that "… a long term target range of .95 to 1.05 for the revenue to cost ratio for each class is reasonable." This continues to be the view of the Board."

EES also reviewed jurisdictional information presented for electric utilities (see below) by FEI in its Reply Argument on COSA and RoR[1] for its 2016 Rate Design Application.

- The Ontario Energy Board approved a 90 to 110 percent range for Hydro One Networks.[2]
- The Ontario Energy Board uses a RoR of wider than 90 to 110 percent for other electric utilities.[3]
- The Prince Edward Island Regulatory and Appeals Commission approved a 90 to 110 percent range for Maritime Electric Company.[4]
- The Newfoundland & Labrador Board of Commissioners of Public Utilities approved a 90 to 110 percent range for Newfoundland Power.[5]
- The Yukon Utilities Board approved a 90 to 110 percent range for the Yukon Energy Corporation.[6]

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[1] FEI Reply Argument on COSA and Range of Reasonableness dated October 2, 2017, pages 22-23.

[2] Ontario Energy Board, Decision EB-2013-0416/EB-2014-0247, In the Matter of an Application by Hydro One Networks Inc. for Approval of Distribution Rates for 2015-2019, dated March 12, 2015. Online: https://www.oeb.ca/oeb/_Documents/Decisions/Dec_Hydro_One_DX_20150312.pdf.

[3] Exhibit A2-13, BCOAPO-Elenchus IR 2.10.1.

[4] Prince Edward Island Regulatory and Appeals Commission, Order UE16-04R, In the Matter of an Application by Maritime Electric Company, Limited to Approve the Rates, Tolls and Charges for Electric Service for the Period Beginning March 1, 2016 and for Certain Approvals Incidental Thereto, dated July 11, 2015 (Docket UE20942). Online: http://www.irac.pe.ca/orders/electric/2016/Order-UE16-04-Combined.pdf.

[5] Newfoundland & Labrador Board of Commissioners of Public Utilities, Order No. P.U. 13(2013), *Decision and Order of the Board In the Matter of a General Rate Application Filed by Newfoundland Power Inc.*, dated April 17, 2013. Online: http://www.pub.nf.ca/orders/order2013/pu/pu13-2013.pdf.

- Within BC, the Commission has applied a 95 to 105 range for electric utilities (FortisBC Inc. and BC Hydro).[7]
- The Nova Scotia Utility and Review Board approved a 95 to 105 percent range for electric utilities.[8]
- The New Brunswick Energy and Utilities Board approved a 95 to 105 percent range for electric utilities.[9]
- The Alberta Energy Board approved a 95 to 105 percent range.[10]

21.3 Please provide the changes in revenue requirements that would be required to bring the R:C ratios for each rate class to 1.

Response:

The Company consulted with EES to provide the following response.

The revenue requirements from the COSA would not be changed as a result of bringing the R/C ratios for each rate class to 1. The R/C ratios for each class could be moved toward unity over time by raising or lowering the amount of revenue collected from each class through adjustments in the rates. The following table shows the required addition/reduction in revenue required to bring each class to a R/C ratio of exactly 100 percent. The table also shows the percent increase/decrease and the increase/decrease on a $ per kWh basis.

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[6] Yukon Utilities Board, Board Order 2005-1, *In the Matter of an Application by Yukon Energy Corporation for Approval of 2005 Revenue Requirements*, dated January 27, 2005. Online: http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%202000/106_boardorder2005_1.pdf.

[7] Exhibit B-11, CEC IR 1.5.2.

[8] *Nova Scotia Power Incorporated (Re)*, 2014 NSUARB 53. Online: http://canlii.ca/t/g63kl.

[9] New Brunswick Energy and Utilities Board, Decision In the Matter of an Application by New Brunswick Power Corporation pursuant to the Electricity Act, S.N.B. 2013, c.7, for the Approval of a Class Cost Allocation Study Methodology, dated May 13, 2016 (Matter No. 271). Online: http://www.nbeub.ca/opt/M/browserecord.php?-action=browse&-recid=456.

[10] Alberta Energy and Utilities Board, Decision 2007-086, *ATCO Electric Ltd. 2008 Distribution Tariff Phase II*, dated November 8, 2007. Online: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2007/2007-086.pdf.

Class	$ Change	% Change	$/kWh Change
Residential	$3,016,853	1.7%	$0.0022
Small Commercial 20	-$732,327	-2.1%	-$0.0024
Commercial 21/22	-$2,391,731	-4.5%	-$0.0042
Large Comm Primary 30/32	-$981,932	-3.8%	-$0.0032
Large Comm Transmission 31	-$466,858	-6.5%	-$0.0049
Lighting	$241,827	8.5%	$0.0167
Irrigation	$96,424	3.0%	$0.0024
Wholesale Primary 40	$1,457,728	3.4%	$0.0029
Wholesale Transmission 41	-$239,985	-3.7%	-$0.0029

21.4 Please provide the changes in rates (assuming changes to the energy portion of the bill) in $ and % that would be required to bring the R:C ratio for each rate class to 1.

Response:

Please refer to the response to CEC IR 1.21.3.

22. Reference: Exhibit B-1, page 55

- In Order G-130-07 in response to BC Hydro's 2007 Rate Design Application, the Commission determined that a "RoR of 95 per cent to 105 per cent [was] the correct range for the purpose of future rebalancing in the circumstances of BC Hydro."[41] The rationale for the decision was based in part on the "the known system demand and demand metering of large commercial and industrial customers" and "the accuracy of the relatively sophisticated load research analysis."[42] As a result, the Commission panel determined for BC Hydro "that the appropriate target R/C ratio in each class is unity or one and that future rebalancing should only be required when a customer class falls outside of the RoR."[43]

- Similarly, in the October 2010 Decision on FBC's 2009 COSA and RDA, the Commission found that "the appropriate RoR of 95% to 105% is the correct range for the purpose of future rebalancing in the circumstances of FBC."[44] As in the BC Hydro decision, the Commission determined the appropriate target R/C in each rate schedule to be one, with future rebalancing necessary only when customer classes fell outside the range. The Commission also accepted FBC's position that the RoR is "based not only on the accuracy of its data, but also on policy considerations such as the Commission's prior decision regarding the RoR for BC Hydro."

As informed by past practice and prior Commission proceedings described later in this section, FBC believes that the appropriate RoR for evaluating its R/C ratios is 95 per cent to 105 per cent. An R/C ratio falling within the 95 percent to 105 percent RoR indicates that the revenues recovered from customers on that rate schedule are adequately recovering the allocated cost to serve them.

22.1 Please provide references with page numbers to all BCUC decisions that make determinations on a COSA range of reasonableness and the appropriate targets in rebalancing.

Response:

The table below provides references to the Commission decisions for both gas and electric utilities that make determinations on a COSA RoR. FBC did research for this response in Rate Design proceedings before the Commission and did not attempt to assess whether the Commission has made COSA-related or RoR determinations in other proceedings such as revenue requirements proceedings.

Application	Commission Order / Decision	Date of Order / Decision	Range of Reasonableness	Target in Rebalancing
Electric - FortisBC				
Rate Design & New Service Options Application [1]	G-15-98	February 13, 1998	N / A	N / A

Application	Commission Order / Decision	Date of Order / Decision	Range of Reasonableness	Target in Rebalancing
2009 Rate Design and Cost of Service	G-156-10	October 19, 2010	Page 4, Directive 9	Page 4, Directive 10
Electric – BC Hydro				
BC Hydro Rate Design Application	G-36-92	April 24, 1992	Decision, Page 15 - 16	N / A
2007 Rate Design Application Phase 1	G-130-07 / Decision	October 26, 2007	Decision, Page 64 – 71	Decision, Page 64 - 71
BC Hydro 2015 Rate Design Application [2]	G-5-17 / Decision	January 20, 2017	N / A	N / A
Natural Gas – FortisBC (FEI)				
Phase B Rate Design Application	G-101-93 / Decision	October 25, 1993	Decision, Page 11, 15	N / A
1996 Rate Design Application [3]	G-98-96 / Decision	October 17, 1996	N / A	N / A
2001 Rate Design Application [3]	G-116-01 / Decision	November 7, 2001	Decision, Page 3	N / A
2016 Rate Design Application [4]	G-4-18 / Decision	January 9, 2018	Decision, Page 23 - 38	N / A
Natural Gas – Pacific Northern Gas				
1991 Rate Design Application	G-23-91 / Decision	February 27, 1991	Decision, Page 38	Decision, Page 28-29
Reconsideration 1991 Rate Design Application	G-42-91	May 23, 1991	Decision, Page 29	
1995 Rate Design Application [5]	G-106-95 / Decision	December 15, 1995	Decision, Section 1.2.1	N / A
1998 Revenue Requirements and Rate Design Application	G-53-98 / Decision	June 18, 1998	Decision, Page 2 of 3 of Executive Summary and Page 27	Decision, Page 2 of 3 of Executive Summary and Page 28-30
Natural Gas – Centra Gas Fort St. John Inc.				
1996 and 1997 Revenue Requirements and Rate Design Application Phase II Rate Design Decision	G-75-96 / Decision	July 12, 1996	Decision, Page 3	Decision, Page 12
Natural Gas – FortisBC (Centra Gas B.C. Inc.)				
2002 Rate Design Application [5]	G-42-03 / Decision	June 5, 2003	Decision, Page 40-41	N / A

Notes:

[1] No determinations were made regarding range of reasonableness and target in rebalancing.

[2] "… Rate Rebalancing Amendment of the UCA, which states that the Commission must not set rates for the purposes of changing the revenue to cost ratio for a class of customers." Page (ii) and discussed on Page 5 of the Commission Decision.

[3] FEI's 1996 and 2001 Rate Design were the result of Negotiated Settlements approved by the Commission.

[4] FEI's 2016 Rate Design Application filing was in compliance to Commission's Order G-21-14 and Decision dated February 26, 2014 regarding Application for Reconsideration and Variance of Commission Order G-26-13 on the FortisBC Energy Utilities' Common Rates, Amalgamation and Rate

Design Application. In both Commission Orders (G-26-13 and G-21-14) and accompanying decisions, no determinations were made regarding range of reasonableness and target in rebalancing.

The 2016 Rate Design Application is still before the Commission; however, in its decision appended to Order G-4-18, the Commission did make a determination related to range of reasonableness, but not on target in rebalancing.

[5] No determinations were made regarding target in rebalancing.

22.2 Please confirm that it is an appropriate interpretation of the above decisions that R:C ratios of unity are the preferred ratios.

Response:

This response also addresses CEC IRs 1.22.3, 1.22.4, 1.22.5, 1.22.6 and 1.22.7.

As explained in response to CEC IR 1.21.1, a Range of Reasonableness RoR around unity for R/C ratios is required to account for various assumptions, estimations, generalizations and judgements involved in COSA study. FBC believes that the appropriateness of RoR depends on the particular circumstances of a utility.

It is incorrect to say that R/C ratios of unity are the preferred ratios. The Commission in its past decisions has directed utilities to use the RoR as a guide to rate setting and rebalancing proposals. In its recent decision on the FEI's cost of service allocation and revenue to cost ratios, the Commission said:

> The panel finds that the R:C ratios should be used to inform rate design and rate rebalancing proposals.[11]
>
> The Panel directs FEI to use an R:C ratio range of reasonableness of 95 percent to 105 percent to inform rate design and rebalancing proposals in the current Application…
>
> …The Panel accepts that in theory an R:C ratio of 100 percent for each rate schedule would indicate that the revenues recovered from each rate schedule are equal to the cost to serve them. However, due to the assumptions, estimates and judgements involved in a COSA study, the Panel considers it appropriate to use a range of reasonableness.[12]

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[11] Order G-4-18 - FEI 2016 Rate Design Application, page 25.
[12] Order G-4-18 - FEI 2016 Rate Design Application, page 35.

As described in Section 3.2 of the Application, FBC's rate design review and proposals are also guided by the widely accepted rate design principles based on Dr. Bonbright's work. FBC believes that the use of a RoR for R/C ratios for a rate design process is based on the cost causation principle as articulated in Principle 2 (Fair apportionment of costs among customers) and represents an important foundation upon which cost allocation and rate design should rest.

Rate design is a complex balancing process, as it frequently requires the application of multiple, and sometimes conflicting, rate design principles and the consideration of viewpoints from various stakeholders. In addition, different rate design principles may have varying levels of importance in different contexts. FBC, therefore, applies its experience and judgement to consider and balance the most relevant principles in a given context when identifying rate design issues and proposing rate design solutions.

In FBC's view, the Commission takes into account all of these rate design principles and other considerations in evaluating a utility's rate design proposals and establishing the appropriate rates.

22.3 Please confirm that the R:C is but one consideration of many in establishing the appropriate rates.

Response:

Please refer to the response to CEC IR 1.22.2.

22.4 Please confirm that the Commission does not require a 'range of reasonableness' to be established in order to set rates either above or below unity.

Response:

Please refer to the responses to CEC IRs 1.21.1 and 1.22.2.

FBC considers R/C ratios and the RoR to be part of a package and to work in concert with each other. Given the uncertainties associated with pinpointing an R/C ratio, a discussion of "unity" without a RoR is artificial. Even though the Commission can set rates above or below an R/C

ratio of 1.0 for reasons other than a Rate Schedule being outside the RoR, the Commission has chosen consistently to make determinations on RoR in rate design proceedings (with exceptions for rate design processes approved via negotiated settlements or where rebalancing is constrained by government direction).

Please also refer to the response to CEC IR 1.21.1 with reference to the point that the RoR should be consistent with industry and past practice.

22.5 Please confirm that the Commission could account for any perceived lack of accuracy in the determination of R:C ratios by applying other considerations such as fairness, impact to customer, customer understanding and acceptance or other measures.

Response:

Please refer to the response to CEC IR 1.22.2.

22.6 Please confirm that the Commission has broad jurisdiction in setting rates and is not beholden to the Revenue: Cost ratios when determining if rebalancing is appropriate.

Response:

Confirmed, in the sense set out in the response to CEC IR 1.22.2.

22.7 Please confirm that removing the concept of a ‘range of reasonableness’ would in no way deprive the Commission of using many considerations such as fairness, customer impact, customer understanding or others to establish rates.

Response:

Please refer to the response to CEC IR 1.22.2.

22.8 Please confirm that the Commission regularly utilizes less than perfect information in its determinations, such as in its calculation of the appropriate Return on Equity and Revenue Requirements and does not apply a 'Range of Reasonableness' to those figures.

Response:

While the Commission must make judgments without perfect information in any of the regulatory matters it considers, the concept of RoR is appropriate in the COSA and Rebalancing context whereas other proceedings mentioned in the question raise distinct issues.

In the case of COSA and rebalancing the use of a RoR is appropriate for several reasons:

- The COSA results and resulting RC ratios are uncertain due to inherent assumptions, estimations, generalizations and judgments used in the COSA study.
- The COSA results and resulting RC ratios are uncertain due to methodological uncertainty. There are multiple acceptable methods to develop the COSA allocation factors (i.e. there is no single right answer). As one example among many, demand-related costs can be allocated using 1 CP, 2 CP, 3 CP, 12 CP, NCP or various other allocation approaches. A second example pertains to Distribution fixed costs which can be split between the customer-related and demand-related components using a minimum system study, the zero intercept method or other methods.
- The use of a RoR with respect to RC ratios and the need for rebalancing is common and accepted practice in utility ratemaking, and has been considered consistently by the BCUC in the COSA / Rate Design proceedings of BC utilities.

In the case of the other two examples in the question (revenue requirements or return on equity) the Commission must approve a specific value in order to set rates. In arriving at a revenue requirements decision the Commission will typically make various adjustments to applied-for amounts (and where cost items are uncertain or difficult to forecast may establish a deferral account or true-up mechanism), but once those determinations are made, rates are adjusted to match revenues with the resulting revenue requirements. Using revenue requirements to illustrate, adopting a RoR would either leave the utility in a position of not having a fair

opportunity to earn its allowed return on equity (on the low end) or leave ratepayers unhappy about rates being biased towards utility overearnings (on the upper end).

23. Reference: Exhibit B-1, page 55 and page 56

5.2.1.1 Rate Rebalancing

As shown in Table 7-10 above, there are two rate classes, Lighting and Large Commercial - Transmission, that have an R/C ratio that falls outside of the RoR of 95 percent – 105 percent. As such, and in accordance with the prior Commission determination that after the rebalancing associated with the 2009 COSA and RDA, future rebalancing should only be required when a customer class falls outside of the RoR,[45] these are the only two classes that are the subject of FBC's rebalancing proposal. FBC proposes to rebalance the Lighting and Large Commercial – Transmission classes.

A summary of the RoR determination from these two classes is found in Table 5-12 below.

Table 5-12: RoR Details for RS 31 and RS 50

Customer Class	Large Commercial Transmission (RS 31)	Lighting (RS 50)
Total Allocated revenue requirement ($)	6,627,451	3,116,434
Pre-Rebalancing Revenues at Existing Rates ($)	7,094,309	2,874,607
Pre-Rebalancing Revenue to Cost Ratio	107.0%	92.2%
RS 50 Revenues at 95% R/C		2,960,612
Revenue Required to move RS 50 within RoR ($)		155,822
Resulting RS 31 Revenue Reduction	155,822	
Resulting Adjusted Revenues	6,938,487	2,960,612
Post Rebalancing R/C Ratio	104.7%	95%

FBC's proposal results in a revenue shift of $155,822, which results in a rate increase to Lighting (RS 50) of 5.4 percent and a rate reduction of 2.2 percent for Large Commercial Transmission (RS 31).

23.1 Considering the decisions G-130-07 and the October 2010 Decision on FBC's COSA determined that the appropriate target was 1, why did FortisBC not target unity when rebalancing instead of the end-points for its 'range of reasonableness'?

Response:

Please refer to the responses to BCUC IRs 1.20.1 and 1.20.2.3.

23.2 Are there any legal or other requirements preventing FBC from rebalancing towards unity? Please explain.

Response:

There is an existing Commission Decision preventing FBC from rebalancing at all where a R/C ratio is within the currently approved RoR (95 percent - 105 percent).

In the Commission's G-156-10 Decision in FBC's 2009 COSA and RDA, the Commission determined the appropriate target R/C in each rate schedule was to be one, with future rebalancing necessary only when customer classes fell outside the range. (Emphasis added)

It is plausible that where a class R/C ratio falls outside of the RoR that rebalancing could occur such that the impacted class would target unity; however, moving these classes in isolation would not be equitable in the view of FBC.

23.3 Please confirm that it would not be difficult or costly for FBC to rebalance rates towards unity.

Response:

Confirmed, in the exercise required on FBC's part to do so. However, please refer to the response to CEC IR 1.23.2 for more conceptual difficulties that arise.

23.4 Would FBC consider it fair if all rate classes were rebalanced either at once or over a period of time towards unity? Please explain why or why not.

Response:

In the view of FBC, rebalancing all customer classes to unity as a result of this COSA would not be fair since the Commission determined in the 2009 COSA process that such rebalancing

would not occur as long as a customer class remained within the established RoR. While the Commission is not bound by the precedent of its decisions, it would seem unfair to reverse a recent decision on a topic of this nature, in conflict with customer expectations, without a compelling change in circumstances.

24. Reference: Exhibit B-1, page 62 and page 62

> ***6.1.4.1 No Natural Gas Access Rate***
>
> A specific rate available only to customers that do not have access to piped natural gas service was raised by participants in the public consultation sessions and was also included as a suggestion in a number of submissions to the Commission in its RIB Report process.
>
> The Company did not model any particular "no-gas" rate as part of its analysis both because such a rate is not appropriate as discussed further below, and that rate mitigation for high consuming customers that fall within this group can be addressed by making changes to the RCR that impact all customers with similar consumption in a similar manner.
>
> The Company agrees that as a group, customers that do not have natural gas service, whether as a result of the lack of gas delivery infrastructure or as a matter of choice, will have an average annual electrical consumption that is higher than residential customers in general. This is also a factor in higher than average annual bills.

24.1 What proportion of FBC customers have no access to natural gas?

Response:

Please refer to the response to BCUC IR 1.37.1.1.

24.2 Assuming customers used natural gas for space and hot water heating, please provide an estimated comparison of the total bills that an average residential customer would experience using natural gas and electricity versus electricity alone.

Response:

Please refer to the response to AMCS IR 1.4.1.

25. Reference: Exhibit B-1, page 63

> 6.1.4.1.1 **NO BASIS IN COST CAUSATION**
>
> The principle of cost causation is a foundational consideration in rate setting. While it is the case that the analysis performed in order to provide the Company's submission in the BCUC RIB Report process indicated that "no-gas" customers had a slightly higher revenue to cost ratio than customers in general, this was due to higher than average revenues and an atypical load profile as opposed to any significant difference in the cost to serve. In addition, it is expected that these factors would be similar to customers that have access to gas, but do not choose to use it. The Commission examined this issue of cross-subsidization as part of the BCUC RIB Report and found no basis to conclude that a cross-subsidy exists. This is not inconsistent with FBC's earlier statement that the group of customers without gas service has higher average annual bills owing to their higher than average consumption.
>
> In addition, there is no justification for singling out the no-gas group for a special rate when there may be a number of factors, such as geography, seasonality, or demographic attributes that, when examined in isolation, may demonstrate a similar apparent intra-class cross-subsidization. Postage stamp rates in general will result in some intra-class subsidies. This does not mean that separate rate classes, or subdivisions within a particular rate class, should be pursued. FBC supports the postage stamp rate concept where all customers with substantially similar characteristics are billed on the same rate.

25.1 Please confirm that the Commission does not typically regulate rates on the basis of end-use, geography, seasonality or other demographic attributes other than by major rate class.

Response:

Confirmed. As explained in the preamble with reference to postage stamp rates, factors such as geography, seasonality or demographics are ordinarily not considered in isolation of the existence of a cost basis. (FBC is aware of limited cases where factors such as seasonality have been considered where there is a cost basis to do so; however, this is not prevalent.) There is no cost justification to single out the no-gas group in this regard.

26. Reference: Exhibit B-1, page 65 and page 66

The available combinations of rate elements and pricing are virtually endless. FBC modelled a limited number of RCR options for discussion at the July open houses based on suggestions received in June that fell into the general categories of:

- Raising the Threshold above the current level of 800 kWh per month (or 1,600 per two months). Some customers indicated that they cannot reasonably stay below 800 kWh. While FBC has explained that customers should not endeavour to restrict consumption to that level, and that the level of consumption that will produce an equivalent bill on the flat rate is closer to 1,250 kWh per month, this has been a recurring suggestion from customers.
- Reducing the Tier 2 rate. Customers indicate that the Tier 2 rate is too high. Based on cost causation/avoidance, FBC agrees that no measure of the Company's Long Run Marginal Cost (LRMC) of power is close to the current 2017 Tier 2 rate of $0.15617 per kWh.

Table 6-4: July 2017 Open House RCR Option Comparison

	Current RCR	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
Customer Charge ($/mo)	16.05	16.05	18.00	16.05	18.99	17.00	18.25
Tier 1 Rate ($/kWh)	0.10117	0.10700	0,10770	0.10750	0.10220	0.10850	0.10800
Tier 2 Rate ($/kWh)	0.15617	0.15617	0.1460	0.14420	0.14800	0.13900	0.13600
Threshold	800	1,000	1,000	800	800	800	800
Annual Consumption (kWh)	Percent of Total Customers	Average Percent Bill Difference					
Above 35,000	2%	(1%)	(6%)	(6%)	(4%)	(8%)	(10%)
30,000 – 35,000	1%	(1%)	(5%)	(4%)	(3%)	(7%)	(8%)
25,000 – 30,000	2%	(1%)	(5%)	(4%)	(3%)	(6%)	(7%)
20,000 – 25,000	5%	(2%)	(4%)	(3%)	(2%)	(4%)	(5%)
15,000 – 20,000	10%	(2%)	(3%)	(1%)	(1%)	(2%)	(3%)
10,000 – 15,000	22%	(1%)	0%	1%	(1%)	2%	2%
5,000 – 10,000	37%	3%	6%	4%	3%	6%	7%
0 – 5,000	21%	3%	9%	4%	6%	7%	10%
Percent > 10%		0%	2%	0%	1%	0%	4%

26.1 Why did FBC not model an option to change the threshold to 1,250 kWh/mo?

Response:

The various options provided to consultation participants were intended to show typical bill impacts associated with representative rate changes. FBC could have modeled any number of rate variations including any number of thresholds, but it would have been impractical to undertake to model all variations.

26.2 What are the advantages and disadvantages of raising the threshold.

Response:

Raising the threshold is typically proposed by customers on the basis that applying the Tier 1 rate to a greater number of kWh in a billing period will provide bill impact mitigation. However, customers often do not realize that raising the threshold will necessitate changing at least one of the other rate components to ensure revenue neutrality. Depending on how the rate is adjusted, this may make a customer worse off rather than better. There is no result, in terms of bill impact, that cannot be accomplished through another means. The only advantage then, would be an improvement in the customer perception of fairness. However, if the result is not as expected this could turn to a disadvantage.

26.3 On what principles was the 800 kWh/mo originally determined? Please explain.

Response:

FBC originally proposed that the threshold originally be set at the median consumption of the residential class, which was 800 kWh per month. This proposal was approved by the Commission.

27. Reference: Exhibit B-1, page 66

At the July open houses, FBC indicated that if it were to recommend a change to the RCR as part of the Application given the information available at the time, these changes would include:

- A moderate increase to the Customer Charge to better reflect the appropriate fixed charges indicated through the COSA;
- A reduction in the spread between the Tier 1 and Tier 2 rates which would best be accomplished through a moderate increase in the Tier 1 rate and a more dramatic decrease in the Tier 2 rate; and
- No change in the Threshold since any change in bill impact a threshold change would cause can effectively be managed through changes in the other rate components.

27.1 Why would a reduction in the spread between Tier 1 and Tier 2 rates be 'best accomplished' through a moderate increase in the Tier 1 rate and a more dramatic decrease in the Tier 2 rate? Please explain.

Response:

In a general sense, it is more appropriate to have the final flat energy rate settle closer to the current Tier 1 rate than the current Tier 2 rate since the Tier 1 rate is closer to the COSA-derived costs that must be recovered through an energy charge. In terms of the specific proposal made in the Application, for an energy rate settling at $0.11749/kWh, this approach is required.

28. Reference: Exhibit B-1, page 67

Table 6-5: RCR with RS 03 Customer Charge

RCR Charge	Current RCR	Equivalent RCR
Customer Charge ($ per month)	16.05	18.70
Tier 1 Rate ($ per kWh)	0.10117	0.10420
Tier 2 Rate ($ per kWh)	0.15617	0.14850
Threshold (kWh / mo.)	800	800

> This rate option was selected from among a number of alternatives based on the range of billing impacts for customers at different consumption levels, if the change was effected in a single year.

28.1 Please provide the alternatives considered by FBC.

Response:

The options considered are those found in the Application in Table 6-4 as well as those presented to customers as found in the consultation materials in Appendix D.

29. Reference: Exhibit B-1, page 68 and page 69

The bill impact of implementing this change is shown in Table 6-6 below.

Table 6-6: RCR with RS 03 Customer Charge - Bill Impact

Annual Consumption (kWh)	Percent of Customers	Average Bill Difference (%)	Average Annual Bill Difference ($)
Above 35,000	2%	(3%)	(292)
30,000 - 35,000	1%	(2%)	(113)
25,000 - 30,000	2%	(2%)	(74)
20,000 - 25,000	5%	(1%)	(36)
15,000 - 20,000	10%	0%	2
10,000 - 15,000	22%	2%	37
5,000 to 10,000	37%	5%	51
0 to 5,000	21%	9%	44

In the above scenario 96 percent of customers have an annual bill increase of less than 10 percent, however, the immediate bill impact on low consuming customers is a cause for concern.

Table 6-7 also shows the year over year bill impact associated with the changes.

Table 6-7: 5 Year Phase-In of Customer Charge Increase

RCR Charge	Current RCR	Year 1 (Jan 2019)	Year 2 (Jan 2020)	Year 3 (Jan 2021)	Year 4 (Jan 2022)	Year 5 (Jan 2023)
Customer Charge ($ per mo)	16.05	16.58	17.11	17.64	18.17	18.70
Tier 1 Rate ($ per kWh)	0.10117	0.10063	0.10017	0.09971	0.09925	0.09880
Tier 2 Rate ($ per kWh)	0.15617	0.15537	0.15466	0.15396	0.15325	0.15254
Threshold (kWh / mo)	800	800	800	800	800	800
Annual Consumption (kWh)	**Percent of Customers**	**Annual Bill Impact**				
Above 35,000	2%	(0.1%)	(0.7%)	(0.4%)	(0.4%)	(0.4%)
30,000 - 35,000	1%	(0.1%)	(0.6%)	(0.3%)	(0.3%)	(0.3%)
25,000 - 30,000	2%	(0.1%)	(0.5%)	(0.3%)	(0.3%)	(0.3%)
20,000 - 25,000	5%	(0.1%)	(0.4%)	(0.2%)	(0.2%)	(0.2%)
15,000 - 20,000	10%	0.0%	(0.3%)	(0.1%)	(0.1%)	(0.1%)
10,000 - 15,000	22%	0.1%	(0.1%)	0.0%	0.0%	0.0%
5,000 to 10,000	37%	0.3%	0.3%	0.3%	0.3%	0.3%
0 to 5,000	21%	1.1%	1.1%	1.1%	1.1%	1.1%

The rates shown in Table 6-7 exclude the impact of any annual revenue requirement impacts and are all based on the forecast load used in the 2017 COSA. Future rate increases would impact all elements of the rate by the same percentage, and would also impact the current exempt flat rate to the same degree. Therefore, any annual rate increases would not change the relative rate levels and at the beginning of the fifth year the RCR and the flat rate would be the same.

The five-year phase-in is effective in ensuring that annual bill impacts are kept to a minimal and manageable level.

29.1 Why did FBC select 5 years as the appropriate phase in period?

Response:

Please refer to the response to BCUC IR 1.46.2.1.

29.2 Please provide Table 6-7 assuming a 2 year and 3 year phase in.

Response:

Please refer to the response to BCUC IR 1.43.1.

30. Reference: Exhibit B-1, page 71

Table 6-9: Transition of RCR to Flat Rate

RCR Charge	Current RCR	Year 1 (Jan 2019)	Year 2 (Jan 2020)	Year 3 (Jan 2021)	Year 4 (Jan 2022)	Year 5 (Jan 2023)
Customer Charge ($ per mo)	16.05	16.05	16.05	16.05	16.05	16.05
Tier 1 Rate ($ per kWh)	0.10117	0.10441	0.10796	0.11175	0.11583	0.12021
Tier 2 Rate ($ per kWh)	0.15617	0.14985	0.14319	0.13607	0.12843	0.12021
Threshold (kWh / mo)	800	800	800	800	800	800
Annual Consumption (kWh)	**Percent of Customers**	**Annual Bill Impact**				
Above 35,000	2%	(3.0%)	(3.2%)	(3.6%)	(4.0%)	(4.4%)
30,000 - 35,000	1%	(2.4%)	(2.5%)	(2.8%)	(3.1%)	(3.4%)
25,000 - 30,000	2%	(2.1%)	(2.2%)	(2.4%)	(2.6%)	(2.9%)
20,000 - 25,000	5%	(1.6%)	(1.6%)	(1.8%)	(1.9%)	(2.1%)
15,000 - 20,000	10%	(0.8%)	(0.8%)	(0.8%)	(0.9%)	(1.0%)
10,000 - 15,000	22%	0.6%	0.7%	0.8%	0.8%	0.9%
5,000 to 10,000	37%	2.1%	2.3%	2.3%	2.5%	2.6%
0 to 5,000	21%	1.8%	2.0%	2.1%	2.2%	2.3%

30.1 Why does FBC consider 5 years to be the appropriate phase in period for a transition to a Flat Rate?

Response:

Please refer to the response to BCUC IR 1.46.2.1.

30.2 Please provide table 6-9 based on transition periods of 2 and 3 years.

Response:

Please refer to the response to BCUC IR 1.45.6.

31. Reference: Exhibit B-1, page 71

> However, there is no cost basis for the current levels of the Tier 1 and Tier 2 rates that form the RCR, nor for any particular threshold and tiered pricing. These rates were initially set to achieve a desired result (lower residential class energy use) within a constraint linked to the annual bill impact of customers. There is no particular relationship between the level of the existing rates, and any operational or cost basis.
>
> In addition, customers have expressed that over the past five years, most of the steps available to reduce the impact of the RCR on billing have been taken. The conservation achieved to date is now embedded in the forecast residential load. Additional conservation is likely subject to diminishing returns and continuing with the RCR into the future not only lacks a cost basis, but may create inequity amongst customers with regard to the ability to take steps to reduce consumption. This conclusion is also consistent with the assumption made during the original 2011 RIB process where the total rate-related conservation impact was assumed to be fully realized over 5 years, or by 2017.[52]

31.1 Please provide the Commission decision establishing the RCR.

Response:

The Commission Order in which FBC was directed to develop a plan for introducing residential inclining block rates and file a RIB rate application is G-156-10, issued October 19, 2010.

The Commission Decision and Order G-3-12 on FBC's Application for a Residential Inclining Block Rate, dated January 13, 2012, are provided as Attachment 31.1.

31.2 Was establishing a price signal for the cost of new energy one of the objectives in determining the RCR? Please explain.

Response:

One of the objectives of the original RIB Application was to introduce price signals for residential customers that *reflect* the marginal cost of electricity being higher than the embedded cost of electricity. The objective, however, was not to set any rate component *at* the cost of new energy. Both the energy rates of the current RCR are above that cost.

31.3 Is it FBC's position that conservation incentives should normally be considered as finite, or continued on an ongoing basis to meet objectives over the long term of a continually changing customer base? Please explain.

Response:

Generally speaking, conservation initiatives should be maintained as long as they are providing a benefit, in terms of lower overall costs to customers, in the short or long term, or as required by legislation. The RCR has neither of these attributes.

32. Reference: Exhibit B-1, page 73

Table 6-10: FBC Residential Rate Proposal

RCR Charge	Current RCR	Year 1 (Jan 2019)	Year 2 (Jan 2020)	Year 3 (Jan 2021)	Year 4 (Jan 2022)	Year 5 (Jan 2023)
Customer Charge ($ per mo)	16.05	16.58	17.11	17.64	18.17	18.70
Tier 1 Rate ($ per kWh)	0.10117	0.10394	0.10699	0.11024	0.11373	0.11749
Tier 2 Rate ($ per kWh)	0.15617	0.14915	0.14188	0.13421	0.12610	0.11749
Threshold (kWh / mo)	800	800	800	800	800	800
Annual Consumption (kWh)	**Percent of Customers**	**Annual Bill Impact**				
Above 35,000	2%	(3.3%)	(3.6%)	(3.9%)	(4.3%)	(4.7%)
30,000 - 35,000	1%	(2.7%)	(2.8%)	(3.1%)	(3.3%)	(3.7%)
25,000 - 30,000	2%	(2.3%)	(2.4%)	(2.6%)	(2.8%)	(3.1%)
20,000 - 25,000	5%	(1.8%)	(1.8%)	(2.0%)	(2.1%)	(2.3%)
15,000 - 20,000	10%	(0.9%)	(0.9%)	(1.0%)	(1.0%)	(1.1%)
10,000 - 15,000	22%	0.7%	0.7%	0.8%	0.8%	0.8%
5,000 to 10,000	37%	2.4%	2.5%	2.6%	2.7%	2.7%
0 to 5,000	21%	3.0%	3.0%	3.0%	3.1%	3.1%

32.1 Please provide Table 6-10 based on a 2 year and 3 year phase in as well as a 6 and 7 year phase in.

Response:

Please refer to the response to BCUC IR 1.46.3 for a version of Table 6-10 showing a 2 and 3 year phase out.

From a review of the 2, 3, and 5 year phase-in scenarios it is apparent that the result of lengthening the phase-out period is to reduce the magnitude of the annual impact by a fairly consistent degree in each year. Therefore, the lengthening of the phase-out period to 6 years would continue to reduce the magnitude of the annual impact, and the lengthening of the phase-out period to 7 years would further continue to reduce the magnitude of the annual impact.

As the re-calculation of these varying scenarios is largely a manual process and is time consuming, and the lengthening of the period to 6 and 7 years will yield predictable results of little if any additional explanatory value, FBC respectfully has not engaged in the exercise of generating a new table with the granularity of the 6 and 7 year numbers.

32.2 Please provide the maximum annual dollar increase for any customer under both 2 and 3 year phase-ins.

Response:

The maximum annual bill increase under a 2 year phase-out is $100.

The maximum annual bill increase under a 3 year phase-out is $68.

32.3 Please provide the maximum % annual increase for any customer under both 2 and 3 year phase ins.

Response:

The maximum per cent increase for any one customer in the 2 year phase-out is 8.8 percent.

The maximum per cent increase for any one customer in the 3 year phase-out is 6.0 percent.

33. Reference: Exhibit B-1, page 74

> FBC will provide those customers that may be adversely impacted by the return to flat rates over the five years with information that will help them assess whether they could benefit from the residential TOU rate, as discussed in Section 8 of the Application.

33.1 Please confirm that all customers will be provided with information that will help them determine whether or not they could benefit from residential TOU rates.

Response:

Please refer to the response to BCUC IR 1.76.5.2.

34. Reference: Exhibit B-1, page 75 and 76

In examining the annual bill impacts that this change is expected to have on Small Commercial customers, FBC calculated the effect on 11,997 of the 13,750 customers (which is the October 31, 2017 count) within the class, which excluded outlying customers that had less than 100 kWh of consumption over the 2016 year. The results are shown in Table 6-12 below. Although the 18.9 percent increase in the Customer Charge appears high, the table shows that while there are increases for a majority of customers, the average amount of those increases is less than one dollar per month. These customers generally have low levels of consumption, and rely on those customers with higher consumption to pay a disproportionate share of the fixed costs of utility operation.

Table 6-12: Rate Schedule 20 – Small Commercial Bill Impacts

Annual Consumption between			# of Customers#	Percent of Customers	Average Percentage Bill Difference	Average Dollar Bill Difference
110,000	and	above	368	3.1	(1.6%)	$(64.14)
100,000	to	110,000	108	0.9	(1.5%)	$(40.09)
90,000	to	100,000	131	1.1	(1.4%)	$(34.90)
80,000	to	90,000	187	1.6	(1.4%)	$(30.17)
70,000	to	80,000	231	1.9	(1.3%)	$(25.15)
60,000	to	70,000	283	2.4	(1.2%)	$(20.11)
50,000	to	60,000	426	3.6	(1.1%)	$(15.22)
40,000	to	50,000	557	4.6	(0.9%)	$(10.08)
30,000	to	40,000	809	6.7	(0.6%)	$(5.19)
20,000	to	30,000	1,413	11.8	(0.1%)	$(0.03)
10,000	to	20,000	2,575	21.5	1.0%	$4.98
0	to	10,000	4,909	40.9	6.6%	$9.67
Total			11,997	100.0		

Overall, 8.7 percent of RS 20 customers would experience a bill impact greater than 10 percent or $41 as a result of the change, based on 2016 billing.

34.1 Please confirm that the Average Dollar Bill Difference represents annual bills and not monthly, or bi-monthly bills.

Response:

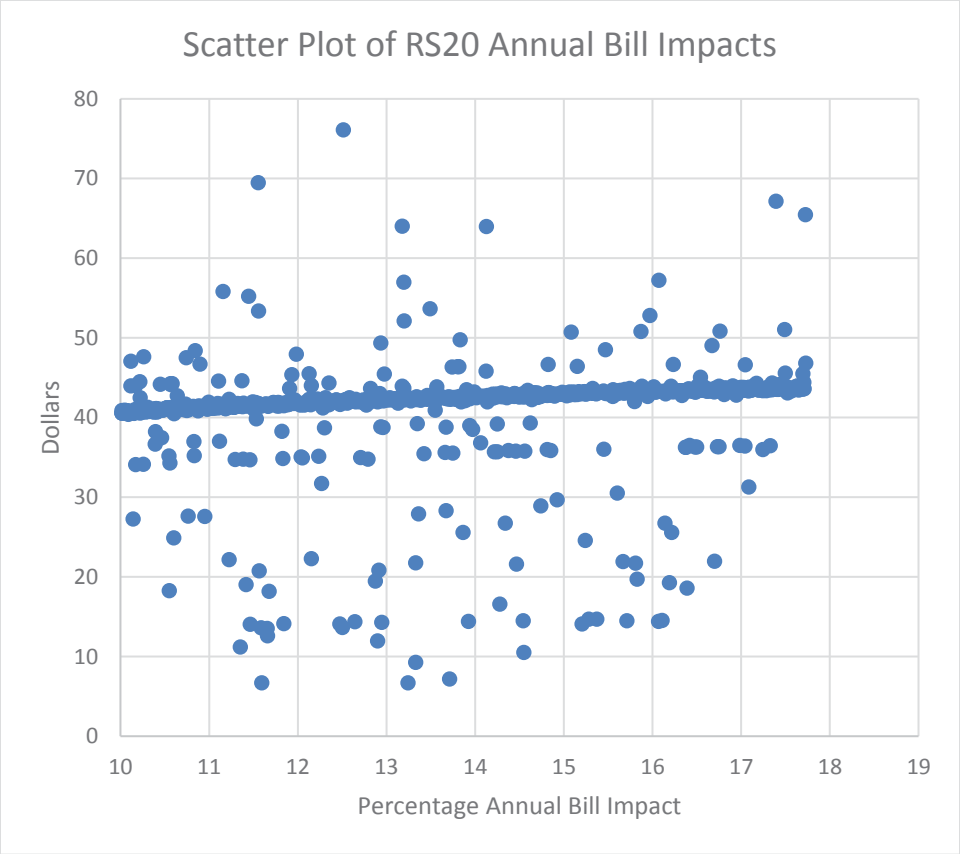
Confirmed.

34.2 Please provide a scatter plot showing the distribution of customers experiencing rate increases greater than 10% by the dollar value of rate increase.

Response:

The requested chart is below. Further detail is also provided in the table that follows.

The table reflects the fact that for the customers with bill impacts above 10 percent (1,039 customers), most have low consumption and relatively low annual bills, so the majority have bill impacts of less than $45 annually on a dollar basis, and only 6 above $60. Most of those customers on average will see an increase of 13.5 percent with a few (6) as high as an average of 14.4 percent.



Bill Impact Range	No of Customers	Average Value of Increase ($)	Average Percent Increase	Average Annual Consumption (kWh)
$60 to $80	6	67.71	14.4	1,059
$40 to $60	923	42.67	13.6	814
$20 to $40	78	32.98	13.6	637
$0 to $20	32	14.16	13.5	268
Total	1039			

34.3 Please complete the following table for customers experiencing bill increases greater than 10%.

Bill Increases	No of Customers	Avg $ Value of Increase	Avg % Increase	Average Consumption
Maximum Bill Increase				
90th %ile				
75th % ile				
50th %ile				
25%ile				

Response:

Please refer to the response to CEC IR 1.34.2.

34.4 Would FBC consider a phased-in approach? Please explain.

Response:

FBC does not believe that the magnitude of the bill impacts for RS 20 customers warrants a phased-in approach. While the percentage increases exceed 10 percent in some cases particularly at very low consumption levels; however, the annual dollar impacts are small.

34.4.1 If yes, over what period of time would FBC consider a phased in approach to be appropriate?

Response:

Not applicable. Please refer to the response to CEC IR 1.34.4.

35. Reference: Exhibit B-1, page 77

The current RS 21 rate components and the corresponding COSA unit costs are shown in Table 6-14 below:

Table 6-14: RS 21 – Current Rate and COSA Unit Costs

Rate Schedule 21 Rate Component	Existing Tariff Rate	COSA Unit Costs	COSA Unit Cost Percentage
Customer Charge ($/mo)	16.48	98.38	16.8%
Tier 1 Energy Rate ($/kWh)	0.08663	0.0408	
Tier 2 Energy Rate ($/kWh)	0.07191		
Demand Rate ($/kVA)	7.72	15.73	49.1%

6.2.2.1 Commercial Rate Discussion

The current Commercial Default Rate has three issues that need to be addressed as part of the Application:

1. The Customer Charge only collects 17 percent of the COSA Unit Cost;
2. The Demand Charge only collects 48 percent of the COSA Unit Cost; and
3. The energy charges are structured as a "declining block" rate, meaning that energy becomes less expensive once a certain amount is consumed in the billing period.

FBC has discussed the fixed charge recovery issues presented by items 1 and 2 earlier in the Application. With regard to item 3, FBC believes that a declining block rate structure runs counter to conservation objectives and should be discontinued. As part of the 2009 Application, RS 21 was partially flattened from a three-tier declining block structure to a two-tier rate for the same reason.

35.1 Please provide the original rationale for the declining block structure.

Response:

Please refer to the response to BCUC IR 1.50.5.

36. Reference: Exhibit B-1, page 78

Table 6-16: RS 21 – Bill Impact by Consumption Strata

Annual Consumption between			# of Customers	Percent of Customers	Average Percentage Bill Difference	Average Dollar Bill Difference
2,200,000	and	Above	21	1.5	1.7%	$5,165.10
2,000,000	to	2,200,000	5	0.4	1.3%	$2,472.67
1,800,000	to	2,000,000	8	0.6	2.9%	$5,415.76
1,600,000	to	1,800,000	9	0.7	1.6%	$2,363.49
1,400,000	to	1,600,000	16	1.2	2.6%	$3,738.58
1,200,000	to	1,400,000	23	1.7	0.9%	$1,130.16
1,000,000	to	1,200,000	27	2.0	2.1%	$2,288.17
800,000	to	1,000,000	47	3.4	1.7%	$1,534.27
600,000	to	800,000	65	4.7	1.5%	$1,366.90
400,000	to	600,000	152	11.1	0.0%	$172.95
200,000	to	400,000	421	30.7	(2.6%)	($371.14)
0	to	200,000	576	42.0	(4.0%)	($363.03)
			1370	100.0		

36.1 Please confirm that the Average Dollar bill difference is an annual bill difference.

Response:

Confirmed.

36.1.1 If not confirmed please identify whether it is monthly or bi-monthly.

Response:

Not applicable. Please refer to the response to CEC IR 1.36.1.

37. Reference: Exhibit B-1, page 78

In terms of the number and percentage of customers with a projected bill impact, Table 9-6 shows the distribution of customers and the percentage bill impact percentage ranges; 4.8 percent of customers have a bill increase greater than 10 percent.

Table 6-17: RS 21 Bill Impact by Percentage

Annual Bill Impact	# of Customers	Percent of Customers	Percent
Greater than 10% Increase	66	4.8	4.8%
5-10% Increase	73	5.3	5.3%
0-5% Increase	311	22.7	22.7%
0-5% Decrease	424	30.9	30.9%
5-10% Decrease	369	26.9	26.9%
Greater than 10% Decrease	127	9.3	9.3%
Total	**1,370**	**100.0**	**100.0%**

37.1 Please confirm that FBC was referring to Table 6-17 rather than table 9-6.

Response:

Confirmed.

37.1.1 If not confirmed, please provide Table 9-6

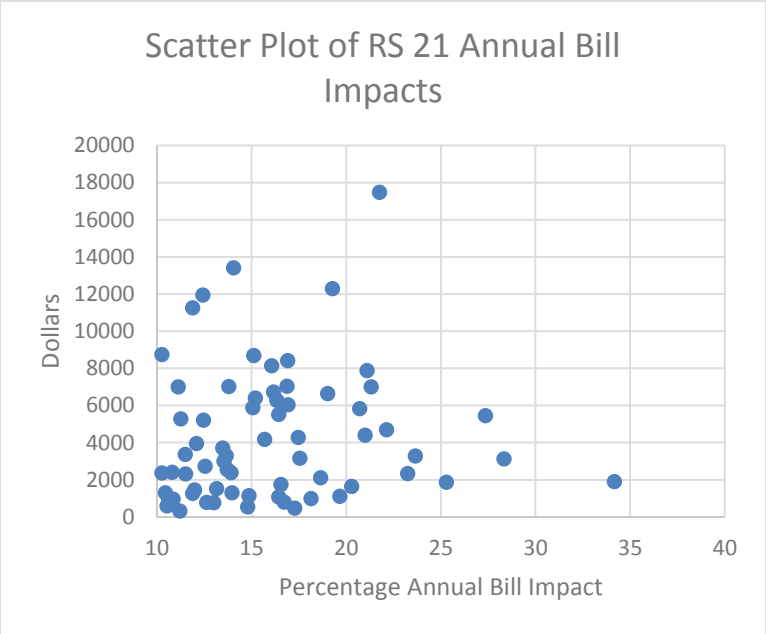
Response:

Not applicable. Please refer to the response to CEC IR 1.37.1.

37.2 Please provide a scatter plot showing the distribution of customers experiencing rate increases greater than 10% by the dollar value of rate increase.

Response:

Please find the requested graph below.



37.3 Please complete the following table for customers experiencing bill increases greater than 10%.

Bill Increases	No of Customers	Avg $ Value of Increase	Avg % Increase	Average Consumption
Maximum Bill Increase				
90th %ile				
75th % ile				
50th %ile				
25%ile				

Response:

Please find the requested information below.

The table reflects the fact that of the few customers with impacts greater than 10%, on average it is customers with relatively low consumption that see the highest annual bill increases on a percentage basis.

Bill Increases	No of Customers	Avg $ Value of Increase	Avg % Increase	Average Consumption (kWh)
Maximum Bill Increase	5	3,215	25.6	27,350
90th %ile	11	6,466	20.4	119,495
75th % ile	17	4,705	16.6	151,857
50th %ile	17	3,958	13.6	181,641
25%ile	16	3,345	11.1	206,265
Total	66			

37.4 Would FBC consider a phased-in approach? Please explain.

Response:

FBC is not proposing to phase-in the RS 21 rate changes because only 4.8 percent of the customers have an annual bill impact greater than 10 percent and there are a much higher number of customers that would benefit from the change. However, FBC is aware that the 4.8 percent of negatively impacted customers may have significant annual increases unless consumption habits change and load profile improves (the average load factor of this group is 5.6 percent).

Rather than phasing in the changes for all customers, FBC would prefer to work with these relatively few customers through its Key Account and Energy Management initiatives to seek ways to mitigate bill impacts.

37.4.1 If yes, over what period of time would FBC consider a phased in approach to be appropriate?

Response:

Not applicable. Please refer to the response to CEC IR 1.37.4.

38. Reference: Exhibit B-1, page 79

> For RS 21, the 2017 COSA indicates that a transformation discount of $0.28 per kW of Billing Demand should be applied to the Demand Charge portion of the rate. The current transformation discount is $0.53 per kW of Billing Demand. FBC is proposing to include the updated amount as the transformation discount in the delivery and metering voltage discounts section of RS 21.[53]
>
> [53] The transformation is currently available only to RS21 and RS30 customers as they have a Demand-related billing component and a higher than standard delivery voltage may be available.
>
> Customers on RS 21 may also be entitled to a metering discount if they are metered at the primary voltage rather than the secondary voltage in recognition of transformer losses. However, since this discount is expressed in tariff as, "a discount of 1 1/2%" applied to the rate, it does not change as a result of the 2017 COSA.

38.1 Please provide an overview of the bill impacts to the customers affected by the change in the discount.

Response:

Please refer to the response to BCUC IR 1.51.2.

39. Reference: Exhibit B-1, page 82

There are only four customers taking service under RS 31, and one is a partial-requirements customer (that is, it is a self-generating customer that does not rely on FBC for its full requirements at all times). Bill impacts of FBC's proposal, based on 2016 billing determinants at current rates compared to the proposed rates, are as shown in Table 6-21 below.

Table 6-21: RS 31 – Bill Impacts by Customer

Customer	Dollar Impact	% Impact
1	(22,031)	(0.49%)
2	2,205	0.11%
3	(267)	(0.09%)
4	20,092	3.92%

39.1 Is the partial requirements customer one of the two customers that will experience a bill increase?

Response:

Yes.

39.1.1 If yes, could the partial requirements customer reduce its load to compensate for the bill impacts if it so desired without significantly disrupting its business activities? Please explain.

Response:

By its nature, a partial requirements customer has latitude to alter its operation to impact utility purchases. In the opinion of FBC, this could likely be done in this case. However, doing so may have an impact on other areas of the customer's operation, such as power sales, which may have an impact on the overall position of the customer. FBC is not in a position to express a view on the overall impact on the customer that would result.

40. Reference: Exhibit B-1, page 82 and page 54

Table 5-11: COSA Revenue to Cost Ratios

Customer Class	Default Rate Schedule	Revenue to Cost Ratio
Residential	RS 01	98.4%
Small Commercial	RS 20	102.2%
Commercial	RS 21	104.7%
Large Commercial Primary	RS 30	104.0%
Large Commercial Transmission	RS 31	107.0%
Lighting	RS 50	92.2%
Irrigation	RS 60	97.2%
Wholesale Primary	RS 50	96.7%
Wholesale Transmission	RS 60	103.9%

6.2.5 Optional Commercial Rates

All of the Commercial Rates currently have an optional TOU rate available. These rates are discussed in Section 8 of the Application which deals with TOU rates in detail.

In addition to the standard default and optional service rates, FBC also offers RS 31 customers that have self-generation with an optional Stand-by Service (RS 37) that provides the customer with a firm supply of electric power and energy when the customer's generating facilities are not in operation or are operating at less than full rated capability. RS 37 was approved recently by the Commission in 2015 and as such FBC is not proposing any changes to this rate schedule as part of the 2017 RDA.

40.1 Please elaborate on why the approval in 2015 means that FBC is not examining RS 37.

Response:

The approval of RS 37 was the result of a separate Commission process that resulted in the Standby rate that is currently in the tariff. There have been no developments since the rate was approved that require it to be re-examined by the Commission. FBC believes that the form of the rate was fully explored during the recent process.

40.2 Please provide the 2015 Decision that resulted in approval of RS 37 and its rates.

Response:

The Stepped and Standby Rates process resulted in numerous Commission Decisions that successively refined the rate.

These Decisions can be located at the follow link:

http://www.bcuc.com/ApplicationView.aspx?ApplicationId=390

40.3 Please confirm that FBC did not conduct a cost of service analysis at this time.

Response:

FBC assumes that "this time" refers to a period coincident with the filing of the Stepped and Standby Rate Application. There was not a full COSA conducted at the time of filing the referenced Application; however, the subject of the cost to serve partial requirements customers was a significant topic of discussion in general terms.

40.4 Please provide a cost of service analysis for RS 37 on the basis used in the application.

Response:

RS 37 was not included in the COSA for the reasons discussed in Section 5.1.1.2.1 of the Application.

The requested information, to the extent it is available is being provided to the Commission in confidence in the response to BCUC IR 1.12.3. This response is confidential since RS 37 has only a single customer and, as such, information of the nature provided relates directly to that specific customer's operations.

41. Reference: Exhibit B-1, page 85

> FBC has examined the impact of this change and finds that these customers have the ability to shift their loads in the non-irrigation season, and that the change would have a minor impact on other customers, but is not proposing the change at this time. As such, the following information is provided for discussion purposes only.
>
> In order to effect this change FBC would need to revise the Rate portion of RS 60 as follows (changes are underlined):
>
> > *During the Non-Irrigation Season*
> >
> > Customers will be transferred to the applicable ~~general~~ Commercial or Commercial – Time of Use service rate. Customers electing a Time of Use option are required to provide notice to the Company by September 1st or non-Time of Use rates will be applied for the entire subsequent non-irrigation season.
>
> FBC believes further investigation into technical and customer information systems issues is required before recommending this change, and these issues may require significant time and expense to overcome. It is also possible that implementation issues may only have solutions that are cost prohibitive. FBC proposes to further investigate the implementation of an off-season TOU Irrigation and Drainage rate and to report back to the Commission.

41.1 Please provide an order of magnitude estimation of the 'minor impact' on other customers that would likely occur.

Response:

Please refer to the response to BCUC IR 1.55.1.

42. Reference: Exhibit B-1, page 86 and 87

A summary of 2017 Wholesale rates and COSA-derived unit costs is shown in the table below.

Table 6-24: Wholesale Rate Details

Rate	Existing Rate	COSA Value	COSA Unit Cost Percentage	Proposed rate
Wholesale Primary (RS 40)				
Energy Charge ($/kWh)	0.05441	0.03887		0.05441
Customer Charge ($/POD/mo)	2645.03	1676.93	158%	2645.03
Wires Charge ($/kVA)	8.98	15.05	60%	8.98
Power Supply Charge ($/kVA)	4.82	6.13	77%	4.82
Wholesale Transmission (RS 41)				
Energy Charge ($/kWh)	0.04501	0.03903		0.04501
Customer Charge ($/mo)	5,974.48	7892.14	78%	5,974.48
Wires Charge ($/kVA)	6.34	6.29	101%	6.34
Power Supply Charge ($/kVA)	4.77	4.66	102%	4.77

6.3.3 Wholesale Rates Discussion and Proposals

FBC is not proposing structural or rate level changes to the default Wholesale rates. In terms of fixed cost recovery, the only rate component that falls short of either the 55 percent Customer Charge or 65 percent Demand Charge threshold is the Wires Charge rate under RS 40, which is at 60 percent.

While there are some variances between the individual COSA-derived unit costs and the rates currently charged to Wholesale customers, in aggregate, the recovery of fixed costs is at a level that is acceptable using the criteria being applied to other rate classes. For this reason, no change is proposed for these rates. The only change being proposed for the Wholesale rates is the addition of a discount to RS 40 for those customers that receive delivery at one or more points of interconnection where the available voltage is at a transmission level (60,000 volts or above). This is discussed in the following section.

42.1 Are there any other rate classes with a customer charge that exceeds 100%?

Response:

After the correction to the RS 40 Customer Charge recovery noted in the response to BCUC IR 1.56.1, there are no classes where the Customer Charge recovery exceeds 100 percent.

42.2 Please confirm that reducing the customer charge and increasing the wires charge for Wholesale Primary customers would result in a rate that more accurately reflects the cost of service.

Response:

Please refer to the response to BCUC IR 1.56.1.

42.3 Please provide a general discussion of the bill impacts that would likely occur if a reduction in the customer charge and an increase in the wires charge were made.

Response:

Please refer to the response to BCUC IR 1.56.1.

43. Reference: Exhibit B-1, page 87

6.3.4 Transmission Discount

FBC is proposing to add a transmission discount to RS 40. The inclusion of a transmission discount is consistent with a similar provision found in both RS 21 and RS 30 that allows a customer that does not meet the eligibility criteria for the rate schedule offering service at a higher voltage to receive a lower rate based on providing their own transformation.

Currently the only Wholesale Transmission rate in the FBC tariff is RS 41 which is derived from the specific load and cost information for Nelson Hydro and is exclusively for the use of the Nelson Hydro. This discount is based on the COSA and effectively excludes some allocated costs for elements of service that are no longer used by the customer. Wholesale-Primary customers are unable to take service under the existing Wholesale Transmission rate (RS 41) since this rate is specific to the service characteristics of the City of Nelson and has no general application to other utilities.

During the consultation that preceded this Application, FBC received correspondence from the City of Grand Forks that it is considering a change to the voltage at which it takes service from FBC. The addition of a transmission discount would facilitate this change without the need for process outside of this RDA, and the discount would then be available for other wholesale customers.

The discount available for Wholesale customers served under RS 40 is determined in the same manner as described for the RS 21 and RS 30 customers (see Sections 6.2.2.3 and 6.2.3.1) and results in rates as follows:

Table 6-25: RS 40 Transmission Discount

Rate	Existing Rate	Discount	Discounted Rate
Wholesale Primary (RS 40)			
Energy Charge ($/kWh)	0.05441	0.0077	0.04671
Customer Charge ($/POD)	2645.03	-	2645.03
Wires Charge ($/kVA)	8.98	2.64	6.34
Power Supply Charge ($/kVA)	4.82	-	4.82

43.1 What, if any, is the likely impact on other rate classes if FBC is to offer a Transmission discount? Please provide a brief discussion with quantification to the extent available.

Response:

Please refer to the response to BCUC IR 1.56.10. There is no impact to other customers by virtue of simply making the discount a feature of the RS 40 rate. There would be an impact to other customers should any or all of the current RS 40 customers become connected at a

transmission voltage; however, the impact would depend on which of the RS 40 customers chose to do so.

44. Reference: Exhibit B-1, page 92 and 94

> Updates to the language contained in RS 101 (Long-term and Short-Term Firm Point-to-Point Transmission Service) and RS 102 (Non-Firm Point-to-Point Transmission Service) are required because the rate schedules, if used to facilitate services other than those anticipated at the time the schedules were originally approved, can be interpreted incorrectly with the potential to lead to FBC being deprived of appropriate revenue that could be used to lower rates for load customers.
>
> In the situation where an Eligible Customer seeks to deliver power generated within the FBC service area to BC Hydro, there is no opportunity for a customer to make use of "two transmission wheeling tariffs". The change that FBC is seeking would maintain the original intent of the anti-pancaking provisions but would allow for the collection of appropriate revenue from IPPs and self-generating customers selling power to BC Hydro, which would provide rate mitigation for all other FBC customers.
>
> As a result of the misinterpretation of the anti-pancaking language, FBC currently has two self-generation customers that are exporting power to BC Hydro and paying no transmission related charges except those for select ancillary services.
>
> FBC requests changes to the text of RS 101 and RS 102 as detailed in the following sections, with the additional language underlined.

44.1 Please provide the revenue that FBC believes it is losing as a result of the self-generation customers exporting power to BC Hydro and not paying transmission related charges.

Response:

Please refer to the response to BCUC IR 1.64.3.

45. Reference: Exhibit B-1, page 32 and page 90

Table 3-2: Current Fixed Cost Recovery Detail

	Current Customer Charge ($/mo)	Customer Charge COSA Unit Cost ($/mo)	Customer Charge Recovery Percent	Current Demand Charge ($/kVA)[32]	Customer Demand COSA Unit Cost($/kVA)	Demand Charge Recovery Percent
Residential (RCR)	16.05	35.60	45%	n/a	n/a	n/a
Residential (Exempt)	18.70	35.60	53%	n/a	n/a	n/a
Small Commercial	19.40	41.75	46%	n/a	n/a	n/a
Commercial	16.48	96.38	17%	7.72	15.73	49%
Large Commercial Primary	945.04	1,474.98	64%	9.19	14.00	66%
Large Commercial Transmission	3,116.03	5,810.78	54%	4.93	7.34	67%
Irrigation	20.96	40.17	52%	n/a	n/a	-
Wholesale Primary	2,645.03[33]	1,676.93	158%	8.98	15.05	60%
Wholesale Transmission	5,978.48	7,892.14	76%	6.24	6.39	98%

[32] Demand Charges shown for Large Commercial Transmission and Wholesale rates are for "Wires" Demand
[33] Customer Charge for Wholesale – Primary is assessed on a per POD/month basis.

Table 7-2: RS 101 Current Firm Point-to-Point Transmission Service Rates

	Large Commercial Service Transmission	Wholesale - Primary	Wholesale - Transmission
	Long-Term Service		
Basic (Customer) Charge ($ Per POD/month)	3,185.00	2,537.00	467.00
Reserved Capacity Charge ($ per kVA)	5.41	9.89	5.10
	Short-Term Service		
Basic (Customer) Charge ($ Per POD/month)	3,185.00	2,537.00	467.00
	Reserved Capacity Charge ($ per kVA)		
Monthly Rate	7.25	13.30	6.85
Weekly Rate	1.87	3.53	1.78
Daily Rate	0.323	0.555	0.311
Hourly Rate	0.016	0.0291	0.015

The current pricing included in RS 102 is summarized in Table 7-3 below:

Table 7-3: RS 102 Non-Firm Point-to-Point Transmission Service Rates

	Large Commercial Service Transmission	Wholesale - Primary	Wholesale - Transmission
	Short-Term Service		
Basic (Customer) Charge ($ Per POD/month)	3,185.00	2,537.00	467.00
	Reserved Capacity Charge ($ per kVA)		
Monthly Rate	7.25	13.30	6.85
Weekly Rate	1.87	3.53	1.78
Daily Rate	0.323	0.555	0.311
Hourly Rate	0.016	0.0291	0.015

45.1 FBC identifies $5,978.48 as the Current customer charge for Wholesale Transmission on page 32. Please identify the rate schedule to which this applies.

Response:

A copy of the portion of RS 41 (Applicable to the City of Nelson) is provided below. The figure of $5,978.48 in Table 3-2 has been mis-typed and should read $5,974.48. A replacement page will be filed as part of an Errata, filed concurrently with these IR responses

SCHEDULE 41 - WHOLESALE SERVICE - TRANSMISSION

APPLICABLE: To supplementary power service to the City of Nelson, subject to written agreement.

AVAILABLE: At suitable City of Nelson interconnections with the Company's 66 kV system.

MONTHLY RATE: A Customer Charge of $5,974.48

plus: A Wires Charge of $6.34 per kVA of Billing Demand; and

plus: A Power Supply Charge of $4.77 per kVA of maximum Demand in current billing month

45.2 Please update Table 3-2 to include RS 101 and RS 102.

Response:

FBC does not have COSA figures for the Customer and Demand Charges available for transmission service customers as this class was not included within the COSA.

46. Reference: Exhibit B-1, page 97 and page 106

FBC is proposing to eliminate the Customer Charge, as it is not a feature of typical Open Access Transmission Tariff (OATT) rates, and to set pricing only according to connection voltage without regard to whether the customer is classed as Commercial or Wholesale. The pricing is derived from the 2017 COSA. Updated rates included in Appendix G and H are as follows.

Table 7-5: Updated PTP Transmission Rates

Delivery	Transmission*	Distribution*
Monthly	4.20	8.07
Weekly	0.9692	1.8623
Daily	0.1381	0.2653
Hourly	0.0058	0.0111

* Per KW of Reserved Capacity Billing Demand

The Minimum Price remains at $0.002/kW/hour.

7.4.8 Summary Tables

Table 7-8: PTP Transmission Rates: Current and Proposed

	Large Commercial Service Transmission	Wholesale - Primary	Wholesale - Transmission	Transmission	Primary
	Current Rates			Proposed Rates	
Long-Term Service					
Customer Charge ($ Per POD/month)	3,185.00	2,537.00	467.00	n/c	n/c
Reserved Capacity Charge ($ per kVA)	5.41	9.89	5.10	n/c	n/c
Short-Term Service					
Customer Charge ($ Per POD/month)	3,185.00	2,537.00	467.00	n/c	n/c
Reserved Capacity Charge ($ per kVA)					
Monthly Rate	7.25	13.30	6.85	4.20	8.07
Weekly Rate	1.87	3.53	1.78	0.9692	1.8623
Daily Rate	0.323	0.555	0.311	0.1381	0.2653
Hourly Rate	0.016	0.0291	0.015	0.0058	0.0111

46.1 Are there any reasons, other than consistency with other OATT rates to eliminate the Customer charge? Please explain.

Response:

The Company consulted with EES to provide the following response.

Yes. The existing rates were based on the assumption that wheeling rates would apply to retail customers that were able to procure their own power supply rather than to wholesale customers that just wanted to use FBC's system to wheel power to facilitate wholesale power transactions. For a retail customer, the Customer Charge is intended to cover the costs associated with meters, service lines, billing, customer service and the customer-related portion of the distribution system. A wholesale transmission customer may not require the installation of a meter or service line, as is the case for a retail customer. They would not use any portion of the distribution system unless they are taking primary level service. Billing and customer service expenses would be minimal for these customers.

46.2 What costs are currently included in the Customer portion of costs and recovered in the Customer Charge

Response:

The Company consulted with EES to provide the following response.

Because the costs were originally set up as retail wheeling rates for each class, and intended to apply to retail customers that obtained their own power supply, the Customer Charge would have been set up to be the same as for retail customers in equivalent classes. The charge would cover the costs associated with meters, services, billing, customer service and the demand-related portion of distribution expenses.

46.3 Why is FBC eliminating he Reserved capacity charge?

Response:

The Company consulted with EES to provide the following response.

The reserved capacity charge is not being eliminated. The new rates do not differentiate between long-term and short-term service and then also show rates for different periods, as is the case with the existing rates. The proposed rates for different periods are intended to cover long-term and short-term service by the nature of the time period used.

46.4 Would the reserved capacity charge be reflective of demand-related costs? Please explain why or why not.

Response:

The Company consulted with EES to provide the following response.

Yes. Wholesale transmission service is based on the costs functionalized as transmission. As transmission is treated as 100 percent demand related in the COSA, and for planning purposes, the charge is reflective of demand-related costs.

46.5 Please provide the % recovery of the Customer charge.

Response:

The Company consulted with EES to provide the following response.

FBC does not have this information available for wholesale transmission customers as this class was not included within the COSA.

46.6 Please provide the % recovery of the Reserved capacity charge.

Response:

The Company consulted with EES to provide the following response.

The wholesale transmission rates are designed to recover 100 percent of the costs associated with the service.

47. Reference: Exhibit B-1, page 110 and 111

> The current TOU rates contain only an on-peak and off-peak period. However, the analysis revealed that it would better reflect system loads to incorporate an on-peak, mid-peak and off-peak period. In developing the structure, EES Consulting confirmed that this is consistent with typical TOU rates of utilities in other jurisdictions, where TOU period have changed from two to three TOU periods within certain months. While the winter and summer months both have relatively higher usage and higher costs in peak hours, loads and costs are lower in the shoulder months. The same is true within days where loads and costs are highest in the morning and early evening.
>
> The analysis also revealed that there is no clear delineation where loads change from one level to another, as changes throughout the day and across months are gradual. There are also some days within a given month where loads are higher because of weather conditions. Loads in each hour were compared to the average load for the day. If the load in these hours was 90 percent or more of the daily peak then the hours were generally considered to be on-peak hours. Mid-peak hours generally reflected hours when loads were between 85 percent and 90 percent of the daily peak.

47.1 Does FBC expect that customers will experience difficulty with the addition of a new 'season' for Time of Use rates? Please explain why or why not.

Response:

FBC does not consider the added season to be difficult for customers to understand or respond to. FBC is offering this rate on an optional basis to gain better data about the response to the rate over the next three years, part of which would be customers' experience with the new TOU seasons and time periods.

Attachment 31.1

IN THE MATTER OF

FORTISBC INC.

RESIDENTIAL INCLINING BLOCK RATE

DECISION

January 13, 2012

BEFORE:

D. Morton, Panel Chair/Commissioner
L.A. O'Hara, Commissioner
M.R. Harle, Commissioner

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1.0 EXECUTIVE SUMMARY

This Decision relates to an application filed by FortisBC Inc. (FortisBC, the Company) to introduce Residential Inclining Block (RIB) rates in its service territory. The filing is in response to an earlier British Columbia Utilities Commission (Commission) directive in Order G-156-10 following FortisBC's 2009 Rate Design and Cost of Service Analysis (2009 RDA) proceeding. A RIB rate is intended to promote conservation by employing a tiered rate structure in which consumption that occurs above a certain threshold level is billed at a higher rate. The higher tier rate is designed to incent customers to reduce their consumption.

The proceeding was conducted as a written hearing. There were 15 Registered Interveners, of which five filed submissions: the BC Sustainable Energy Association (BCSEA), Mr. Andy Shadrack, Nelson Hydro, British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO), and Strata Corporation KAS2464 (Strata KAS2464). The Applicant originally filed 18 different RIB rate options, all with the same basic structure of a Customer Charge, a threshold, and two block rates. During the hearing, a considerable number of additional options were explored. The Applicant submits that Option 8, with the following components:

- A Customer Charge of $29.65 per billing period;
- A bi-monthly threshold of 1,600 kWh;
- A Block 1 rate of 8.453 cents per kWh; and
- A Block 2 rate of 12.408 cents per kWh.

is the most effective approach. The Option 8 charges shown above assume an implementation date of January 1, 2012. This option is approved as requested. The Panel also approves FortisBC's proposed Pricing Principle 1, which governs how the RIB prices will be calculated in subsequent years. FortisBC is directed to apply Pricing Principle 1 to future rate increases for the years 2012 to 2015. Specifically:

a. The Customer Charge is exempt from general rate increases, other than rate rebalancing increases;

b. The Block 1 rate is subject to general and rebalancing rate increases; and

c. The Block 2 rate is increased by an amount sufficient to recover the remaining required revenue (i.e., the residual rate).

In its determination, the Panel considers several factors, including bill impacts, conservation, Bonbright Principles, and FortisBC's proposed pricing principles for the years 2012 to 2015 that will guide FortisBC in applying rate increases going forward. We discuss how these considerations affect the Customer Charge, the threshold, and the Block 1 and Block 2 rates. The Panel also considers the relationship between the Block 2 rate and FortisBC's long-run marginal cost of energy.

FortisBC is directed to implement the residential RIB rate as soon as is reasonably practicable, and by no later than July 31, 2012. It is also directed to establish a control group and such monitoring as is required to enable it to provide a RIB Rate Evaluation Report (Report) on conservation impacts of the RIB rate. FortisBC is also directed to include in the Report an update of the Conservation Potential Review; an in-depth analysis of its long-run marginal cost including the cost to distribute and transport the energy; the potential effect of a two-tier wholesale rate; and an analysis of the interaction of RIB and Time-of-Use (TOU) rates, should TOU rates be implemented during the reporting period. The reporting period is to run from the implementation date to December 31, 2013 and the Report is to be submitted to the Commission by no later than April 30, 2014.

2.0 INTRODUCTION

This Decision relates to an application filed by FortisBC to introduce Residential Inclining Block rates in its service territory (the Application). The Application is in response to an earlier Commission directive in Order G-156-10 following FortisBC's 2009 Rate Design and Cost of Service Analysis proceeding. A RIB rate is intended to promote conservation by employing a tiered rate structure in which consumption that occurs above a certain threshold level is billed at a higher rate. The higher second tier, or "block" rate, is designed to incent customers to reduce their consumption.

There were 15 Registered Interveners in the proceeding including a number of individual residential customers, associations, and corporations.

The introduction of RIB rates in the FortisBC service area is befitting an era where the provincial legislation encourages conservation and British Columbia Hydro and Power Authority (BC Hydro) has had a residential inclining block rate structure in place since October 2008.

2.1 Application

On March 31, 2011, FortisBC filed an Application for Residential Inclining Block rates pursuant to Directive 10[1] of Commission Order G-156-10 which was issued following FortisBC's 2009 RDA proceeding. Directive 10 directs FortisBC "... to develop a plan for introducing residential inclining block rates that also incorporate a lower Basic Charge in the immediate future and to file an RIB rate application with the Commission no later than March 31, 2011."

---

[1] Directive 10 in fact refers to the number in the Summary of Directives in the FortisBC 2009 RDA Decision. That Directive is Directive 5 in Order G-156-10. FortisBC refers to Directive 5 in Footnote 7 on p. 14 of the Application and again at p. 1 of its Final Submissions.

Accordingly, FortisBC applies under sections 58 – 61 of the *Utilities Commission Act* (*UCA*) for Commission approval of a new, two-tier, inclining block rate for its residential customers who are currently served under Rate Schedule RS 01. The RIB rate is intended to be the default, mandatory rate for all residential customers who are not taking service under FortisBC's TOU option, Rate Schedule 2A. This structure, if approved, will result in new rates upon implementation. The Application also seeks approval of a Pricing Principle on a go-forward basis, which will determine how each of the three rate elements (i.e., the Customer Charge, the Block 1 rate and the Block 2 rate) will be increased to meet the general revenue requirement adjustments required each year. (Exhibit B-1, p. 1)

2.2 Legislative and Regulatory Context

2.2.1 Legislative Framework

Utilities Commission Act

Section 59 of the *UCA,* in part, requires the Commission to set rates for a public utility that enable the utility to earn a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property. Further, a public utility must not make, demand or receive a rate that is unjust, unreasonable, unduly discriminatory or unduly preferential or contravenes the *UCA*, the regulations, orders of the Commission or any other law. Section 60, in part, provides that in setting a rate, the Commission may use any mechanism, formula or other method of setting the rate that it considers advisable and may order that the rate derived from such mechanism or formula or other method is to remain in effect for a specified period.

Clean Energy Act

The *Clean Energy Act* (*CEA*) received Royal Assent on June 3, 2010. The *CEA* advances 16 specific energy objectives to help achieve British Columbia's energy vision including new measures to

promote electricity efficiency and conservation. One of these efficiency and conservation objectives is to take demand-side measures and to conserve energy.

The *CEA* defines **"demand-side measure"** to mean a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand.

(*CEA*, Section 2)

The BC Energy Plan (2007): A Vision for Clean Energy Leadership

Prior to the introduction of the *CEA*, the provincial government's emphasis on the promotion of energy efficiency was articulated in both the 2002 and 2007 Energy Plans. The 2007 Energy Plan includes, among other things, the following two Policy Actions relating to energy conservation and efficiency:

> **Policy Action #2:** Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.
>
> **Policy Action #4:** Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.

The 2007 Energy Plan also lists the following future energy efficiency and conservation initiatives in more detail:

- Continuing to remove barriers that prevent customers from reducing their consumption;
- Building upon efforts to educate customers about the choices they can make today with respect to the amount of electricity they consume;

- Exploring new rate structures to identify opportunities to use rates as a mechanism to motivate customers either to use less electricity or use less at specific times (emphasis added);
- Employing new rate structures to help customers implement new energy efficient products and technologies and provide them with useful information about their electricity consumption to allow them to make informed choices (emphasis added); and
- Advancing ongoing efforts to develop energy-efficient products and practices through regulations, codes and standards.

(The BC Energy Plan (2007), p. 5)

FortisBC states it believes that its RIB rate proposal is "one component within a comprehensive demand reduction strategy that helps the Commission and the Province fulfill conservation goals." (Exhibit B-1, p. 8)

2.2.2 The 2009 RDA Decision

In the 2009 RDA Decision, the Commission rejected FortisBC's position that no conservation rates should be introduced before FortisBC implemented its Advanced Metering Infrastructure (AMI) and by Directive 10 directed FortisBC to introduce RIB rates. The Commission articulated its reasons as follows:

- The timeline for the AMI implementation is subject to a number of factors with a potential outcome that introduction of wide spread time-of-use (TOU) rates could be five years away, which is contrary to the intent of the government policy;
- Hourly customer consumption data (available only after the introduction of the AMI) is not necessary to the design of a RIB rate structure. BC Hydro introduced RIB rates in October 2008 – long before its planned Smart Meter installation;
- The Commission Panel disagrees with the FortisBC position that a customer choosing to use less electricity during the peak periods will not use more electricity during the off-peak period to compensate; and
- The Panel is not persuaded by the FortisBC argument that customers would be confused over introduction of two kinds of conservation rates over a short period of time.

By way of summary, the Commission was "especially concerned that backing away from the RIB rate structure in the FortisBC service area today, in anticipation of TOU rates being implemented in five years time, would represent a foregone opportunity for energy efficiency and conservation." (2009 RDA Decision, pp. 56-57)

2.3 Orders Sought

Pursuant to sections 58-61 of the *UCA*, FortisBC is seeking Commission approval to implement a RIB rate structure that reflects two steps, or blocks, and incorporates the following design features:

- A threshold level of bi-monthly consumption, above which the Block 2 rate will apply, set at 1,600 kWh;
- A Customer Charge of $28.93 per two-month billing period, exempt from revenue requirement rate increases, with only rebalancing adjustments applied in future years (Customer Charge and Basic Charge are used interchangeably in this Decision);
- A Block 1 rate and a Block 2 rate determined using the customer impact criterion that 95 percent of customers are subject to annual billing increases no greater than 10 percent as a result of the RIB rate structure;
- The Block 1 rate adjusted by an amount equal to the sum of the general revenue requirement increase and rebalancing adjustments; and
- The Block 2 rate adjusted by an amount sufficient to recover the balance of the general revenue requirement and any rebalancing adjustments after the Customer Charge and Block 1 rate are calculated (the residual rate).

(Exhibit B-1, Appendix B)

FortisBC proposes to implement the RIB rate between six and nine months after receiving the Commission's Decision on the Application. It states that introducing a RIB rate is a significant change that must be preceded and accompanied by thorough information and a customer education component, the development of which cannot commence until direction is provided. (Exhibit B-1, p. 2)

A January 1, 2012 implementation date, using the methodology described in the Application to determine the rate, would produce a RIB rate with the following components:

- A Customer Charge of $29.65 per billing period;
- A Block 1 rate of 8.453 cents per kWh; and
- A Block 2 rate of 12.408 cents per kWh.

These rates are further addressed in Section 4.5. It should be noted, however, that due to some concerns regarding the evidence submitted and related procedural delays, as addressed in Section 2.4, the most likely implementation will now take place in the second half of 2012. This could result in additional adjustments to the rates shown above.

2.4 Regulatory Process

FortisBC proposed a written hearing process, which included only one round of Information Requests (IR), and concluded on June 15, 2011 with the filing of its Reply Submission. Based on this regulatory timetable FortisBC anticipated the RIB rate structure would become effective January 1, 2012. (Exhibit B-1, p. 3)

However, a number of events occurred that resulted in a longer written hearing process. Some of these occurrences were the following:

- Additional rounds of IRs;
- Discussions between Commission staff and FortisBC regarding technical issues that arose while reviewing the responses to IR1;
- Establishment of a Procedural Conference for August 3, 2011 where the Commission Panel sought submissions on seven issues, including sufficiency of the evidentiary record, pricing principles, and conservation impact; (Exhibit A-15) and

- Based on the submissions received on August 3, 2011, the Panel determined that in many instances the record was inadequate to support FortisBC's submissions. Accordingly, the Commission Panel directed FortisBC to file additional evidence addressing, among other issues, revenue stability, calculation of 2012 RIB rates, long-run marginal costs, elasticity and conservation measures, and Basic Charge. (Exhibit A-17)

A more detailed description of the regulatory process is provided in Appendix A.

3.0 OVERVIEW OF FORTISBC PROPOSAL

3.1 Framework for Proposed RIB Rate Structure

FortisBC states the Bonbright Principles continue to provide a framework against which all rate design activities and options can be compared. These principles, as paraphrased by FortisBC, are shown below:

Principle 1	Recovery of the revenue requirement;
Principle 2	Fair apportionment of costs among customers (appropriated cost recovery should be reflected in rates);
Principle 3	Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy);
Principle 4	Customer understanding and acceptance;
Principle 5	Practical and cost-effective to implement (sustainable and meet long-term objectives);
Principle 6	Rate stability (customer rate impact should be managed);
Principle 7	Revenue stability; and
Principle 8	Avoidance of undue discrimination (interclass equity must be enhanced and maintained).
	(James C. Bonbright, Principles of Public Utility Rates, Columbia University Press, 1961)

As a conservation rate, a RIB rate's main purpose is to induce conservation. It is generally acknowledged that the RIB rate design is conducive to savings in energy and its impact on savings in demand is only coincidental to customers' response to the RIB rate design (Exhibit B-5, BCUC 1.9.3; BCUC 1.17.6). The other conservation rate currently in use at FortisBC is its Time-of-Use rate. The purpose of the time-based rate is to conserve capacity (Exhibit B-12, BCUC 2.4.1). FortisBC submits that customers who choose to take service under the TOU billing would not be compelled to move to the RIB rate (FortisBC Final Submissions, p. 1).

Under the Bonbright Principles against which all RIB rate options are evaluated, the RIB rate option that is most preferred would be one that induces the most conservation and also balances the competing Bonbright objectives.

In this Application, FortisBC analyzes 18 rate scenarios and further evaluates the scenarios for a preferred option by making choices that include meeting the following relevant objectives:

- Customer bill impact (Bonbright Principles 4 and 6, customer understanding and acceptance, and rate stability);
- Efficient Price Signal (Bonbright Principle 3, price signals that encourage efficiency use and discourage inefficient use); and
- Promotion of Conservation (Policy Action #44 from the 2007 Energy Plan).

3.2 RIB Rate Scenarios Proposed

FortisBC states that in an effort to design a rate that (i) FortisBC customers will understand, (ii) maintains provincial consistency, (iii) meets the defined objectives, and (iv) complies with the Commission directive, it has restricted the options to RIB rate structures that vary the following four components:

1. Customer Charge: The customer charge is the fixed portion of the bill that does not vary with usage. Typically, the customer charge is used to recover the costs incurred by the utility of providing services such as billing and meter reading to customers. The Commission has specifically directed FortisBC to submit an inclining block rate option that includes a lower customer charge. (Order G-156-10, Directive 5);
2. Threshold: A threshold in an inclining block rate is the kWh consumption level at which the price for each subsequently consumed kWh will increase;
3. Block 1 rate: The rate, expressed in cents per kWh, at which each kWh of consumption up to the threshold is billed; and

4. Block 2 rate: The rate, expressed in cents per kWh, at which each kWh of consumption above the threshold is billed.

The Application includes 18 RIB rate scenarios (Options 1-18) for comparison.

FortisBC states that the Customer Charge under the Rate Schedule (RS) 01 was forecast to be $28.93 per two-month billing period effective May 1, 2011. This number became the starting point for the RIB rate design work. FortisBC points out that at its current level the Customer Charge collects "just under 44 per cent of the amount required by strict adherence to cost causation principles." FortisBC further states that, as the Commission has determined the proposed RIB rate will include a reduction in the Customer Charge, the level at which it will be ultimately set becomes somewhat arbitrary. To gauge the impact of a lower Customer Charge on the other rate components, FortisBC selected a bi-monthly Customer Charge of $21.50 to model for analysis.

For the threshold level, FortisBC has modeled the following three bi-monthly thresholds based on customer billing data from 2009 and 2010:

- Mean Consumption: 2,100 kWh
- Median Consumption: 1,600 kWh
- 85 percent of Median: 1,350 kWh

For each combination of the two customer charges ($28.93 and $21.50) and the above three threshold levels, FortisBC then specified three permissible customer impact levels:

1. 90% of customers will see a RIB related increase of less than or equal to 10%;
2. 95% of customers will see a RIB related increase of less than or equal to 10%; and
3. 100% of customers will see a RIB related increase of less than or equal to 10%.

(Exhibit B-1, p. 17)

The customer impact criterion is expressed in terms of the percentage of residential customers who will experience an annual rate impact due solely to the implementation of the RIB option of less than 10 percent. FortisBC notes that the 10 percent figure is generally seen as the threshold of "rate shock", though it is not an official position of the Commission.

These permutations become the 18 RIB rate scenarios included in the Application for further analysis. (Exhibit B-1, pp. 14-17)

3.3 Evaluation Criteria

For each of the 18 RIB rate scenarios, FortisBC determined the following RIB rate evaluation criteria.

Table 1: RIB Rate Evaluation Criteria

Evaluation factor	Description
Annual Breakeven kWh	The level of annual consumption required to have annual billing under the RIB rate option equal annual billing under the current flat rate option.
Percentage of Customers That Benefit	The percentage of customers whose annual bill for electricity is lower under the RIB Rate option than under the existing flat rate.
Maximum Bill Impact	The highest single percentage increase experienced by a customer in any month when the RIB rate option is compared to the flat rate.
Percentage of Customers with Bill Increases > 20%	The percentage of customers who will experience an annual increase in their bills greater than 20% when billing under the RIB rate option is compared to billing under the existing flat rate.
Number of Customers With Consumption in Block 2 At Least Once	The number of customers who will have consumption in a billing period in the second block at least once in a year.
Percentage of Load Billed in Block 2	Of the total residential load (in kWh), the percentage that is consumed in the second block.
Conservation Impact	The conservation impact of a RIB rate option is the estimated reduction in both consumption and demand that is attributable to the implementation of the given RIB rate option.

Source: Exhibit B-1, p. 20, Table 7-1

To reduce the 18 rate scenarios to a smaller set of scenarios for further analysis, FortisBC relied on the following three RIB rate objectives:

> Customer Bill Impacts: Customer bill impacts, while unavoidable, should not be unreasonable. FortisBC states that the evaluation of customer bill impacts should be informed by concurrently examining the criteria "Maximum Bill Impact" and "Percentage of Customers with Bill Increases > 20%" (Exhibit B-5, BCUC 1.8.1);
>
> Efficient Price Signals: The differential between Block 1 and Block 2 rates must be sufficient to provide a meaningful signal to incent conservation behaviour (the first screening criterion); and
>
> Promotion of Conservation: The total residential load that would be billed in the second block, as a percentage of the entire load, became the second screening criterion.

FortisBC states that by applying the above two screening criteria, it reduced the 18 RIB rate scenarios down to four scenarios (Options 2, 8, 11 and 17) which would be analysed by applying different Pricing Principles over the 2012-2015 time period.

3.4 Pricing Principles for 2012 to 2015

FortisBC states that it must design a RIB rate that will recover its annual revenue requirements for the residential customer class, which becomes a constraint by making it impossible to vary each RIB rate component independently. At a minimum, one of the four variables will be dependent on the levels chosen for the other three. FortisBC designed its 18 RIB rate scenarios to cover its 2011 revenue requirements to begin with. Subsequently, FortisBC had to develop pricing principles regarding how to apply future general revenue requirement related rate increases to each of the three rate components in future years.

FortisBC further states it has based the analysis on the residential rates expected to be in effect as of May 1, 2011. This includes the impact of the 2.5 percent rebalancing increase as approved by Commission Order G-196-10, but does not include any forecast interim flow-through rate adjustments related to the BC Hydro 2012-2014 Revenue Requirements Application. (Exhibit B-1,

p. 15)

The Company takes the position that it is complying with Commission Order G-156-10 to introduce a lower Customer Charge by exempting the existing Customer Charge from future general rate adjustments other than those related to rebalancing through 2015. FortisBC's rationale is that this Pricing Principle effectively reduces the Customer Charge relative to other billing determinants over time. (Exhibit B-1, p. 16)

To further test the remaining four scenarios, FortisBC designed four Pricing Principles to apply the following anticipated residential rate increases to the three rate components.

Table 2: Forecast Residential Rate Increase

Rate Component	2012	2013	2014	2015
	(%)			
Revenue Requirement Increase	6.4	4.2	3.4	6.5
Rebalancing	2.5	2.3	-	-
Total Increase	8.9	6.5	3.4	6.5

Source: Exhibit B-1, p. 25, Table 8-2

Two of the four scenarios (Options 2 and 8) are designed on the above stated premise that the Customer Charge is exempt from rate increase, except for rate balancing adjustments. In these cases, FortisBC explored the following alternatives:

<u>Pricing Principle 1</u>

- The general and rebalancing rate increases are applied to the Block 1 rate; and
- The Block 2 rate is increased by an amount sufficient to recover the remaining required revenue; i.e. the residual rate.

<u>Pricing Principle 2</u>

- The Block 1 rate is frozen; and

- The Block 2 rate is increased by an amount sufficient to recover the required revenue; i.e., the residual rate.

For the remaining two scenarios (Options 11 and 17) the following alternatives were explored:

Pricing Principle 3

- General and rebalancing rate increases applied equally across the Customer Charge and Block 1 rate components; and
- The Block 2 rate is increased by an amount sufficient to recover the remaining required revenue; i.e. the residual rate.

Pricing Principle 4

- Block 1 rate is frozen;
- General and rebalancing increases applied to the Customer Charge; and
- Block 2 rate increase by an amount sufficient to recover the remaining required revenue; i.e. the residual rate.

(Exhibit B-1, p. 25)

3.5 Option 8: FortisBC's Preferred Option

Upon further review, FortisBC eliminated half of the above permutations from consideration due to the high and increasing ratio between the Block 1 and Block 2 rates. FortisBC submits that a second block rate that is too high will be unduly punitive to higher consumption customers, such as those with electric heat. Any scenario in which the annual rate increases are only applied to the Block 2 rate results in such a high ratio.

FortisBC further states that the ratio between Block 1 and Block 2, which is an indication of the conservation incentive provided by the rate, should also remain fairly constant and not decrease over time to the point where this incentive is no longer effective.

As the final outcome of its selection process, FortisBC recommends Option 8 as its preferred option and proposes the following Pricing Principle (Pricing Principle 1):

- A Customer Charge frozen at the existing level, with only rebalancing adjustments applied in future years;
- A Block 1 rate adjusted by an amount equal to the sum of the general revenue requirement increase and rebalancing adjustments; and
- A Block 2 rate adjusted by an amount to recover the balance of the general revenue requirement and any rebalancing adjustments.

The resultant RIB rate structure, based on May 1, 2011 rate levels, is comprised of:

- A bi-monthly Customer Charge of $28.93;
- A Block 1 rate of 7.828 cents per kWh;
- A Block 2 rate of 11.272 cents per kWh, reflecting a 44 percent differential between the two blocks; and
- A bi-monthly threshold of 1,600 kWh.

(Exhibit B-1, p. 27)

3.6 RIB rates and TOU rates

FortisBC refers to its public consultation with respect to customers' preferences for various residential rate options, which was conducted in late 2009. As part of that consultation, FortisBC included a number of RIB rate options in addition to the existing flat rate option.

By way of summary, FortisBC states that the consensus reached during the public consultation, as well as its preference, was for maintaining the status quo pending the AMI implementation. The RIB rate option was seen by customers as a viable option, although it had lower support than

waiting for AMI. Based on the above, FortisBC believes that customer acceptance will be largely based on credible evidence on conservation impacts and careful management of bill impacts. (Exhibit B-1, pp. 12-13)

Based on the Commission directives in Order G-156-10 and BC Hydro's submission in a recent application (RIB Re-Pricing Application) that after its implementation of Smart Meters and Infrastructure Program, BC Hydro would not propose a mandatory TOU rate, FortisBC's current position is to offer a suite of time-based rates to complement its mandatory RIB rate. (Exhibit B-5, BCUC 1.6.4; BCUC 1.4.3.3)

This topic will be addressed in further detail in Section 4.9.

4.0 KEY ISSUES AND COMMISSION DETERMINATIONS

4.1 Residential Inclining Block Rate and its Structure

4.1.1 FortisBC Submission

The RIB rate option proposed by FortisBC has the same four basic components as that implemented by BC Hydro: a Customer Charge, a single threshold, and two block rates. In its Final Submission, FortisBC submits that: "A RIB rate composed of those four components offers provincial consistency, and alternative structures were therefore not included as an option in the original Application."

In addition, FortisBC also provides a non-exhaustive list of examples of other potential RIB rate structures, including:

- RIB rates featuring multiple thresholds and rate blocks;
- RIB rates that include a time component such as hourly or seasonal blocks;
- RIB rates that contain a demographic parameter such as income or heating fuel choice;
- RIB rates that feature a geographic parameter; and
- RIB rates that feature an individual customer consumption baseline.

However, it "believes that consistency with the four component rate structure adopted by BC Hydro is a desirable component of its RIB rate and that the Commission should not consider any rate variant that does not comply." (FortisBC Final Submission, p. 2)

4.1.2 Intervener Submissions

Strata KAS2464 believes the RIB rate proposal mutes market forces and blunts the imagination and innovation of the future. It submits that overall the negative possibilities outweigh the positive benefits. However, it acknowledges that if the Commission continues to believe that conservation can be efficiently promoted via a residential inclining block rate, the FortisBC proposal with its various shortcomings is the preferred option. (Strata KAS2464 Final Submission, p. 3)

The BCOAPO expresses concern about the specific rate proposed and submits that introducing a rate where both blocks will vary from the Long-Run Marginal Cost (LRMC) more than the current flat rate within the short term is counterproductive because it does not promote the efficient use of electricity while causing material customer impacts. Further, it "…sees no value in a rate design for a rate design's sake and submits that the objective is not and should not be simply to reduce use for its own sake, but to do so when and if it makes sense." In summary, the BCOAPO maintains that "…it may be a difficult pill for parties to swallow… to find that the correct action is no action at all, but that is, in BCOAPO's submission, the case here." (BCOAPO Final Submission, p. 6)

BCSEA agrees with FortisBC's proposed RIB rate structure, containing a Customer Charge, a threshold and two block rates. (BCSEA Final Submission, p. 1) No other Interveners commented on this issue.

4.1.3 FortisBC Reply

In Reply, FortisBC notes that "…the BCOAPO does not offer any opinion on what different conclusion or recommendation in terms of an appropriate rate would result from an alternate approach." (FortisBC Reply Submission, p. 11)

4.1.4 Commission Determination

As previously described in this Decision, this Application was brought forward by FortisBC in response to a directive by the Commission. This directive is supportive of the objectives of the *CEA* for British Columbia to take demand side measures, to conserve energy, and to achieve electricity self sufficiency. These objectives can benefit from the use of conservation rates, such as the RIB, for electricity. The issue before the Panel is how best to structure a conservation rate to decrease demand and induce conservation in an efficient manner – a manner that optimizes the utilization of resources.

In a competitive market, rising prices affect consumers' behaviour by sending a price signal to induce consumers to reduce consumption. Thus, rising prices discourage the uneconomic use of scarce resources. In a perfectly competitive market, the price of any increment of a resource will be driven to the full economic cost of that increment, and will therefore be an "economic efficient" price which achieves optimal resource utilization.

In the absence of market pricing, as is the case in the regulated sector, the challenge for utilities and regulators is to establish an economic efficient price, or rate, that encourages energy conservation while ensuring that the utility's revenue requirement is met. While an arbitrary increase in a rate may well encourage less consumption, it may not be an economically efficient reduction in consumption. In any event, given revenue requirement constraints, a flat rate cannot simply be increased. An inclining block structure, which charges a lower rate for amounts consumed below a threshold and a higher rate above that threshold, can potentially be structured to be both economically efficient and meet the utility's revenue requirements. However, a RIB rate structure that is incorrectly priced can have disadvantages and unintended consequences, the principal among them being that customers overuse underpriced resources and underuse overpriced resources. The choices made are suboptimal and the consequence is lower productivity and/or lower conservation. A rate structure based on sound rate-making principles can ensure that what consumers pay will reflect the true economic value of the energy they buy, and that energy resources find their best possible uses.

Bonbright Principle 3 embodies this notion and accordingly, the Panel gives this principle added weight in its consideration. The Panel is of the opinion that the RIB rate structure proposed by FortisBC - a relatively simple inclining pricing structure - incents conservation. However, other Bonbright Principles which provide, for example, for fairness, and stability must also be considered. In this regard, the Panel notes that FortisBC has considered such issues as bill impacts, ease of understanding and rate stability in the design of its proposed RIB rate Option 8. These considerations will be discussed further in subsequent sections of this Decision.

An important characteristic of a RIB rate structure is that it allows the utility to introduce price signals that reflect the increased marginal cost of electricity. Setting the Block 2 rate equal to the LRMC and allowing the Block 1 rate to be set residually ensures that any consumption, in excess of the threshold, is billed at the LRMC. The Panel considers this to be a key element of a RIB rate that can be used to induce conservation and be economically efficient. The Panel notes that while the BCOAPO does not appear to object to the notion of a RIB rate, it does not agree with the RIB rates as proposed because the Block 2 rate is not significantly below the LRMC and could potentially exceed it in the near future**.** The Panel does not agree with this assessment for the reasons given in Section 4.6.3, where we discuss the relationship between FortisBC's LRMC and the approved RIB rate option in more detail.

The Panel also does not agree with the negative possibilities of the RIB rate proposal as articulated by Strata KAS2464. There has been no evidence provided that would support its position that RIB rates mute market forces and stifle innovation.

The Panel is satisfied that the introduction of a RIB rate, in addition to being an effective tool in promoting conservation; is simple for the utility and users to understand; does not unduly discriminate against certain segments of residential ratepayers, as we will discuss in Section 4.2.3; and promotes revenue stability as we will discuss in Section 4.2.3. **Accordingly, the Panel finds that a RIB rate structure is in the public interest and directs FortisBC to implement this rate structure, subject to the parameters described below.**

With regard to the four-component RIB structure proposed by FortisBC, the Panel is supportive of its goal to maintain provincial consistency. The single threshold with two blocks is simpler to implement and understand - for both the utility and its customers – when compared to structures with multiple thresholds. Of the other potential RIB rate structures cited, each introduces a challenge or complexity not present in the proposed structure. For example, there may be privacy issues associated with approaches that require the utility to obtain demographic information from its customers; individual customer baselines may be perceived as unfair and also present difficulties from an implementation and operations perspectives; multiple thresholds may be confusing for some or many customers. These issues have been explored in considerable detail in previous BC Hydro RIB rate hearings and the Panel is satisfied with the Applicant's choice in this regard. **The Commission Panel directs that the FortisBC's RIB rate consist of four components: a Customer Charge, a threshold, and two block rates.**

Although no submissions were received on the specific implementation date, the Panel notes that in the Application and the proposed regulatory schedule included therein, FortisBC estimated an implementation date of April 1, 2012. Given schedule delays, we acknowledge that this date may no longer be feasible. However, we do encourage FortisBC not to delay the implementation process any further. **Accordingly, FortisBC is to implement the RIB rate as soon as is reasonably practicable and by no later than July 31, 2012. FortisBC is to file a revised Tariff Sheet for Rate Schedule 01 no later than 30 days prior to the date the RIB rate becomes effective.**

4.2 Customer Charge

Directive 5 of Order G-156-10 ordered FortisBC "... to develop a plan for introducing residential inclining block rates that also incorporate a lower Basic Charge in the immediate future...". As described earlier, FortisBC's proposed Option 8 would exempt the Customer Charge from rate adjustments other than those related to rebalancing through 2015. FortisBC submits that this rate design effectively reduces the Customer Charge over time relative to other billing determinants. (Exhibit B-1, p. 1) FortisBC further notes that, upon implementing the RIB rate in 2012, the

Customer Charge will also decrease in absolute terms as compared to the Customer Charge that would be in effect in 2012 if the RIB rate were not put in place. Indeed, in 2012, the Customer Charge would increase to $29.65 per billing period with a RIB rate or, by contrast, it would increase to $31.25 if the flat rate structure was maintained, assuming that the 2012 rate increase requested by FortisBC in its 2012-2013 Revenue Requirements Application is approved. (FortisBC Final Submission, p. 4)

Other levels of Customer Charge have been explored as part of this proceeding. They are $0.00, $7.50, $10.00, $15.00 and $21.50.

In FortisBC's RIB rate proposal, the Customer Charge is also a determinant of the Block 1 and Block 2 rates. This is because the rates are determined by first selecting a Customer Charge, a threshold, and an allowable customer bill impact, and then finding the unique combination of Block 1 and Block 2 rates that collects the required revenue.

4.2.1 FortisBC Submission

FortisBC submits that the Customer Charge should not be lowered other than as achieved by applying FortisBC's proposed Pricing Principle as described above for three reasons:

- The current level of the Customer Charge is already below the COSA-derived amount;
- Fixed costs, to the extent possible, should be recovered through fixed charges; and
- Revenue stability for the utility should be considered.

(FortisBC Final Submission, p. 4)

Further to the last point above, FortisBC maintains that "the collection of fixed costs through fixed charges, as well as the established need for revenue stability needs to be considered. Decreasing the customer charge and increasing the energy charges adds sales revenue volatility. FortisBC believes that its proposal provides an appropriate balance between the needs of the Company and

the concerns customers may have with the level of the customer charge." (BCUC 1.1.12.4)

Beyond these reasons, FortisBC demonstrates that lowering the Customer Charge below $28.93 would result in smaller block differentials and lower conservation impacts, all else being equal. (FortisBC Final Submission, pp. 4-5)

4.2.2 Intervener Submissions

BCSEA agrees with FortisBC that the evidence supports the above conclusion and adds that, for any given bill impact constraint, increasing the Block 1/Block 2 rate differential has a larger impact on conservation than does increasing the energy charges by decreasing the Customer Charge. BCSEA places a priority on maximizing conservation within various constraints and, accordingly, supports approval of FortisBC's proposal regarding the Customer Charge. (BCSEA Final Submission, p. 4)

BCOAPO acknowledges that FortisBC's most recent Cost of Service Analysis (COSA) based on its 2009 RDA indicated that the true cost of service per account was almost twice the current Customer Charge. Therefore, BCOAPO submits that there is no reason to either change FortisBC's Customer Charge if the Commission approves a RIB rate or reduce the Customer Charge in any future rate designs. (BCOAPO Final Submission, p. 6)

Mr. Shadrack states that his household "... would be quite happy if that basic charge was reduced over a similar five-year period to avoid rate shock" and "believes that the goal should be to reduce the Customer Charge to $9.78." The methodology suggested by Mr. Shadrack differs from the approach taken by FortisBC in its Application and would see absolute decreases applied to the Customer Charge in each of the five years. However, Mr. Shadrack also comments that if the Commission does not lower the Customer Charge, then it must direct FortisBC to address how it would ensure that those who reduce their electrical consumption, under an inclining block rate, are not going to end up being financially penalized. He also submits that when setting the Customer Charge, the difference between FortisBC's Customer Charge and that of BC Hydro should be considered. He maintains that "….this anomaly must be addressed in a timely manner." (Shadrack

Final Submission, p. 2)

Despite not commenting specifically on the Customer Charge or any other elements of the proposed RIB rate, Strata KAS2464 submits that the FortisBC proposal, with its various shortcomings, is the preferred option should the Commission continue to believe that conservation can be efficiently promoted via a RIB rate. (Strata KAS2464 Final Submission, p. 3)

Finally, Nelson Hydro, which describes itself as an interested but not directly affected party, believes that holding the Customer Charge fixed and applying increases only to the energy charges appears to be a good way to make the transition from cost-based to conservation-based rates. (Nelson Hydro Final Submission, p. 2)

4.2.3 Commission Determination

The Panel does not agree with the submission of Mr. Shadrack that the difference between BC Hydro's and FortisBC's Customer Charges must be addressed, or, indeed, that it even constitutes an anomaly. The cost structures of the two utilities are different, which alone could lead to a difference in the Customer Charge. In any event, how BC Hydro determines its Customer Charge is not within the scope of this hearing. Further there has been no evidence provided in this hearing to show that FortisBC's Customer Charge is anomalous. The Panel notes that in this Application, FortisBC demonstrated that its bi-monthly Customer Charge was well within the range of the residential customer charges of other major utilities in Canada (ATCO Limited Electric, ENMAX Power Company, EPCOR Utilities Inc., Toronto Hydro, Hydro Ottawa, NS Power, NF Power, NB Power (Urban). (Exhibit B-11, p. 28) For those utilities, FortisBC shows that the adjusted 2-month Customer Charge averages $31.28. The Panel also notes that in the FortisBC 2009 RDA, FortisBC submitted a comparison of the Customer Charges for Saskpower, NB Power, NF Power, Manitoba Hydro, Hydro Quebec, NS Power and BC Hydro. This comparison shows FortisBC's proposed Customer Charge lying below the average monthly Customer Charge of $15.34 for those utilities.

The Panel acknowledges the need for revenue stability and notes FortisBC's comments that decreasing the Customer Charge could increase revenue volatility, a claim which no Intervener has refuted.

For these reasons, the Commission Panel is persuaded by FortisBC's submission regarding the Customer Charge and **approves its proposal to set the Customer Charge at $28.93 based on May 1, 2011 rates and exempt it from general rate increases, other than rate rebalancing increases for the years 2012 to 2015.**

4.3 Threshold

A threshold in an inclining block rate is the kWh consumption level above which the price for each subsequently consumed kWh is billed at the Block 2 rate. As noted earlier, the threshold is also one of the key determinants of the Block 1 and Block 2 rates in FortisBC's proposed RIB rate design. Based on 2009 and 2010 customer billing data, FortisBC has modeled three threshold levels, corresponding roughly to the residential mean consumption (2,100 kWh), the residential median consumption (1,600 kWh) and a kWh value set at approximately 85 percent of the median consumption (1,350 kWh). (Exhibit B-1, p. 17)

A threshold set at 1,500 kWh has also been examined through the written hearing process.

4.3.1 FortisBC Submission

FortisBC has selected a threshold of 1,600 kWh per billing period for Option 8, its preferred RIB rate option, which corresponds to the median consumption for residential customers. This threshold would result in approximately 37 percent of the load being billed at the Block 2 rate. (Exhibit B-1, p. 18)

FortisBC acknowledges that the Commission, in Order G-124-08, approved BC Hydro's RIB rate threshold at 1,350 kWh, a reduction from BC Hydro's proposed 1,600 kWh threshold, in order to expose more customers to the Block 2 rate and in consideration of a letter from the Minister of Energy, Mines and Petroleum Resources citing the threshold at 10 percent below the average usage. However, FortisBC notes that in its case, all other RIB rate determinants remaining unchanged, a similar determination would effectively prompt the approval of Option 2 rather than Option 8. (FortisBC Final Submission, p. 3) This would result in lower Block 1 and Block 2 rates with no anticipated increase in conservation. (Exhibit B-11, Appendix B) Furthermore, FortisBC notes that in the BC Hydro case, a threshold of 1,600 kWh results in approximately 62 percent of customers being billed at the Block 2 rate at least once while a threshold of 1,200 kWh would see that number rise to 74 percent. By contrast, a FortisBC threshold set at 1,600 kWh would result in 72.8 percent of customers being billed at the Block 2 rate at least once. Therefore, FortisBC essentially shows that the difference in characteristics between the two utilities means that approximately the same proportion of customers would be billed at the Block 2 rate despite the different thresholds. (FortisBC Reply Submission, p. 6)

FortisBC also states that setting the threshold near the median level provides a rationale that is both easy to understand and communicate to customers and sees no compelling reason to vary the threshold from its proposed 1,600 kWh value. (FortisBC Final Submission, p. 3)

4.3.2 Intervener Submissions

No Intervener took issue in written submissions with the threshold proposed by FortisBC.

In BCSEA's view, three main alternatives have emerged for the RIB rate threshold that can each be relatively easily communicated:

- 1,600 kWh per billing period, preferred by FortisBC, is roughly the residential median consumption;

- 1,500 kWh per billing period is roughly 90 percent of the residential median consumption (Exhibit B-13, BCSEA 2.15.1) and is the basis of the BC Hydro's RIB threshold; and
- 1,350 kWh per billing period is BC Hydro's actual RIB threshold.

(BCSEA Final Submission, p. 4)

BCSEA acknowledges that while a lower threshold exposes more customers to the Block 2 rate, it yields a conservation estimate that is either the same as or, in some designs, slightly lower than with a higher threshold. Therefore, BCSEA tends to agree with FortisBC that there is no compelling reason to vary the threshold from the proposed 1,600 kWh value, although it would also find acceptable thresholds of either 1,500 kWh or 1,350 kWh per billing period. (BCSEA Final Submission, p. 5)

The BCOAPO makes no submission regarding the threshold level. As part of his proposed alternative RIB rate design, Mr. Shadrack supports setting the threshold initially at 1,600 kWh per billing period and lowering it by 15 percent to 1,350 kWh over five years. Strata KAS2464 does not mention the threshold specifically, but indicates its support for FortisBC's preferred option should the Commission approve a RIB rate. (Strata KAS2464 Final Submission, p. 3) Likewise, Nelson Hydro supports the RIB rate option proposed by FortisBC without commenting expressly on the threshold level. (Nelson Hydro Final Submission, p. 3)

4.3.3 Commission Determination

Once the Customer Charge has been established, the remaining elements of the RIB rate can now be set. The threshold value is the amount of monthly consumption above which a customer is billed at the higher rate. Because of the constraint that the amount of revenue recovered by the RIB rate cannot exceed the amount of the approved revenue requirement for the residential customer class, the Block 1 rate will necessarily be less than the current flat rate while the Block 2 rate will be above it. Thus, if customers were billed only at the Block 1 rate, whatever it may be, they will pay less for their electricity under the RIB rate than they do currently under the flat rate.

The Panel is of the opinion that it is desirable to ensure that as many customers as possible incur the Block 2 rate at some point during any given year.

A key determinant, then, in setting the threshold value is the percentage of customers that will be billed in the higher rate at least once in any given year. Generally speaking, the lower the threshold, the more customers are exposed to the higher Block 2 rate. The higher the threshold, the fewer customers will be exposed to the Block 2 rate.

As previously discussed, BC Hydro's initial RIB rate application proposed 1,600 kWh, which was subsequently reduced to 1,350 kWh, in large part because this threshold represents 10 percent below the average usage and would result in increased billing at the Block 2 rate. FortisBC's proposed threshold of 1,600 kWh, although substantially higher than the threshold adopted by BC Hydro, results in roughly the same proportion of customers being billed at the Block 2 rate. **The Panel approves the threshold of 1,600 kWh proposed by FortisBC**. While making this determination, the Panel also notes the observation of BCSEA that while a lower threshold generally exposes more customers to the Block 2 rate, in these particular circumstances, the conservation savings may not actually be higher with a lower threshold. In its Final Submission, it compares Option 2, with a threshold of 1,350 kWh with Option 8 (with a 1,600 kWh threshold). Both options have identical conservation savings.

4.4 Customer Impact Criterion

The customer impact criterion is the last of three key determinants used by FortisBC to determine the Block 1 and Block 2 rates, along with the Customer Charge and the threshold. The customer impact criterion is expressed in terms of the percentage of residential customers who will experience an annual rate impact due solely to the implementation of the RIB rate of less than 10 percent. FortisBC has modeled three levels of allowable customer bill impact, which can be summarized as 90 percent, 95 percent, or 100 percent of customers will see a RIB-related increase of less than or equal to 10 percent. (Exhibit B-1, p. 17)

4.4.1 FortisBC Submission

FortisBC proposes a RIB rate option that incorporates the 95 percent customer impact criterion. FortisBC is concerned about the potential impact of a RIB rate on its customers and therefore seeks a balance between its needs and those of its customers while also considering the goal of conservation. FortisBC acknowledges that allowing a greater percentage of its customers to experience more than 10 percent annual bill impact results in greater anticipated conservation. However, it does so by lowering the Block 1 rate further to create a larger block differential. This potentially results in greater gains to some customers with no accompanying behavioural changes while exposing a larger number of customers to high bill increases. FortisBC also believes that an unduly punitive rate that may disproportionately affect a sub-group of customers, such as those with electric heat, should be avoided. FortisBC submits that the relatively modest increases in conservation results do not justify the move from the 95 percent to the 90 percent customer impact criterion. (FortisBC Final Submission, pp. 6-7)

4.4.2 Intervener Submissions

No Intervener took issue with FortisBC's position with respect to the need to consider consumer impact. In particular, BCSEA noted that Customer Rate Impact (Bonbright Principle 6) and Efficiency Inducing Price Signals (Bonbright Principle 3) were given "additional weight" in the Commission's Decision in the recent BC Hydro RIB Rate Re-Pricing Decision (page 14-28 of Appendix A to Order G-45-11) and as such acknowledges that these two considerations properly form a primary part of the evaluation of FortisBC's proposed RIB.

However, BCSEA strongly supports approval of a RIB rate design based on the 90 percent customer impact criterion, as the RIB rate options based on this bill impact constraint consistently induces more conservation than those based on the 95 percent customer impact criterion, all else being equal. BCSEA submits that the most important choice in designing a RIB rate that induces the most conservation while meeting the other valid constraints and objectives is the adoption of the 90 percent bill impact constraint. BCSEA compares the conservation results anticipated under

FortisBC's preferred option (Option 8) with those under Option 7, which differ only with respect to the customer impact criterion. BCSEA disagrees with FortisBC's characterization that the conservation differential between those two options is "relatively modest" and shows graphically that Option 7 achieves substantially more conservation than Option 8. BCSEA further disagrees with the premises that customers with electric heat are a sub-group that would be disproportionately impacted by Option 7, as those customers are distributed across the spectrum of low to high consumption. In fact, BCSEA shows how Options 7 and Option 8 result in exactly the same impact in terms of the percentage of customers with electric heat who see a bill decrease (59 percent) or a bill increase (41 percent). To conclude, BCSEA submits that the Commission should prefer RIB rate designs based on the 90 percent customer impact criterion because those designs induce substantially more conservation without causing unacceptable bill impacts. (BCSEA Final Submission, pp. 1-3)

BCOAPO does not specifically comment on the appropriate level of customer bill impact in its written submission. Nonetheless, BCOAPO acknowledges that customer bill impact should form a primary part of the evaluation of FortisBC's proposed RIB. (BCOAPO Final Submission, p. 2)

Mr. Shadrack also does not comment specifically on the appropriate level of customer bill impact in his written submission.

Strata KAS2464 does not mention the customer impact criterion specifically, but indicates its support for FortisBC's preferred option should the Commission approve a RIB rate. (Strata KAS2464 Final Submission, p. 3) Likewise, Nelson Hydro supports the RIB rate option proposed by FortisBC without commenting expressly on the various individual rate components. (Nelson Hydro Final Submission, p. 3)

4.4.3 FortisBC Reply

In Reply, FortisBC notes that in his written submission, Mr. Shadrack did not explicitly express support for one of the customer impact criteria over another. The Company submits, however,

that given Mr. Shadrack's alternative RIB rate proposal, with both a Customer Charge and a Block 1 rate predetermined, the use of the customer impact criterion in the manner in which FortisBC proposes is precluded and ultimately, the customer bill impact is ignored in the determination of the rate.

FortisBC stresses that the customer impact criterion, as an integral input into the determination of the rate itself, is more than just a yardstick for gauging the changes to bills as a result of the RIB rate. Furthermore, the selection of one customer impact level over another while holding the Customer Charge and threshold constant constitutes a trade-off between conservation and customer impact. FortisBC asks: Is the greater conservation potential worth the associated increase in negative customer impact? Its view is that customer impact directly influences the general acceptance of the rate – a key consideration when implementing a new rate. In conclusion, FortisBC submits that while the BCSEA acknowledges that it "... puts a priority on maximizing the amount of conservation", FortisBC seeks a balance that considers as fundamentally important the impact on customers. (FortisBC Reply, pp. 2-3)

4.4.4 Commission Determination

The Panel agrees that customer impact is an important criterion and will thus consider customer impact in its further determination of the appropriate RIB rate components.

FortisBC is proposing a RIB rate option with a customer impact of 95 percent (Option 8). The Panel accepts BCSEA's submission that a level of customer impact greater than this can, all else being equal, encourage greater conservation, and its proposal to adopt a 90 percent customer impact level (Option 7). Although FortisBC characterizes the conservation differential between Option 7 and Option 8 as being "relatively modest," BCSEA submits that the conservation savings associated with Option 7 are approximately half as much compared to those of Option 8. (Final Submission, BCSEA, p. 2) However, the Panel notes that consideration must be given, when weighing conservation benefits against bill impacts, to the factual basis of these two elements. There is an acknowledged uncertainty surrounding elasticity estimates and the resulting conservation

forecasts. (FortisBC Final Submission, pp. 10-11) This is in contrast to the considerably better understanding of bill impacts and the fact that bill impacts may affect customers with large families and not just profligate consumers of electricity. Given this, the Panel is inclined to give somewhat more weight to the bill impacts than the conservation impacts.

In addition, this increase in conservation comes at a cost, which is disproportionately borne by a small sub-group of ratepayers. For example, in its Reply Submission, FortisBC estimates that the percentage of customers with bill increases above 20 percent rises from 0.2 percent to 2.7 percent when the customer impact changes from 95 percent to 90 percent. Additionally, the maximum bill impact rises from 22.6 percent to 36.2 percent and the Block 1 rate falls further below the current flat rate.

The Panel questions whether it is just and fair to disproportionately burden these ratepayers while, in essence, reducing rates for a greater number of customers. BCSEA argues that Option 7 is not "punitive", nor does it agree "with the premise that customers with electric heat are a sub-group that would be disproportionately impacted by Option 7." (BCSEA Final Submission, pp. 1-3) BCSEA further submits that a RIB rate is not inherently unjust, unreasonable, unduly discriminatory or unduly preferential. The Panel agrees, but is of the opinion that a RIB rate should be calibrated to ensure that the intended benefits are not out of proportion to their costs and that these costs should be borne by as broad a base of ratepayers as possible. **Thus the Panel agrees with FortisBC's proposed 95 percent bill impact criteria.**

4.5 Block 1 and Block 2 Rates

The Block 1 and Block 2 rates are determined as a function of the Customer Charge, threshold and customer impact criterion, meaning that for each combination of these three determinants, there is only one combination of Block 1 and Block 2 rates that would collect the required revenue. (Exhibit B-1, p. 17)

4.5.1 FortisBC Submission

Given FortisBC's position regarding the Customer Charge, threshold and customer impact criterion, as described in Sections 4.2 to 4.4 above, FortisBC's proposal for a RIB rate remains its original preferred option (Option 8). A January 1, 2012 implementation, using the methodology described in the Application to determine the rate, would produce a RIB rate with the following components:

- A Customer Charge of $29.65 per billing period;
- A Block 1 rate of 8.453 cents per kWh; and
- A Block 2 rate of 12.408 cents per kWh.

(FortisBC Final Submission, p. 7)

This determination is described at length in Exhibit B-11, in response to the Commission's request for clarification on how 2012 rates are to be calculated, as well as in Exhibit B-13 in response to BCOAPO IR2 Q4a. (FortisBC Final Submission, pp. 7-8) The above RIB rate stands in contrast to the current flat rate, which if continued in 2012, would yield a Customer Charge of $31.25 and an Energy Charge of 9.816 cents per kWh. FortisBC notes that the actual RIB rate will vary from the above description as it depends upon the month of implementation and the amount of actual residential consumption that occurs up to the implementation date while under the flat rate. (FortisBC Final Submission, p. 7)

4.5.2 Intervener Submissions

BCSEA did not comment specifically on the attributes of Block 1/Block 2 rates in FortisBC's proposed Option 8 or in any other RIB rate options. However, FortisBC's proposed RIB rate components as described in Section 4.5.1 cannot be supported by BCSEA given its support for the 90 percent customer bill impact, as opposed to the 95 percent customer bill impact supported by FortisBC.

BCOAPO submits that "there really is no need for FortisBC to implement a RIB rate in order to send the proper price signals to customers" and that "the correct action is no action at all." (BCOAPO Final Submission, p. 6) As a result, BCOAPO did not comment on the specific levels of the Block 1 and Block 2 rates.

Strata KAS2464 and Nelson Hydro express their overall support for the RIB rate as proposed by FortisBC without commenting specifically on the levels of the Block 1 and Block 2 rates.

4.5.3 FortisBC Reply

In Reply, FortisBC stresses that if levels for the Customer Charge, threshold and customer impact criterion are selected and deemed to be the most appropriate on an individual basis but then generate a Block 1 and Block 2 rate combination that is ineffective or unpalatable, then one may conclude that a RIB rate may not provide the best solution. Furthermore, manipulating the rate themselves would compromise the other rate determinants. (FortisBC Reply, p. 7)

4.5.4 Commission Determination

The Panel recognizes that once the three key determinants - the Customer Charge, threshold and customer impact criterion - have been selected, there is only one combination of Block 1 and Block 2 rates that can satisfy the revenue requirement constraint. **Given the Commission Panel's approval of FortisBC's proposal for each of the determinants, it follows that the Panel also agrees with its proposal for the Block 1 and Block 2 rates. The Panel also acknowledges that the Block 1 and Block 2 rates will differ somewhat from the values of 8.453 and 12.408 cents per kWh respectively as they are dependent upon the specific 2012 implementation date.**

4.6 FortisBC's Long-Run Marginal Cost

The issue of determining FortisBC's true LRMC arose as the Commission probed the potential relationship between the utility's LRMC and the level of the Block 2 rate and, in particular, the appropriateness of capping the Block 2 rate at the LRMC.

FortisBC defines LRMC as the cost to acquire additional energy where existing resources are insufficient to meet load requirements. In the near to medium term, FortisBC expects to meet incremental requirements through increased market purchases. (Exhibit B-8, Commission Panel IR 7.1) This is why, in a first instance, FortisBC calculated its LRMC based on the forecast of the market price of energy as opposed to construction of new resources. In the additional evidence filed at the Commission Panel's request, FortisBC acknowledged that a LRMC from new resources could be developed from a forecast of the cost of potential new resources. FortisBC submits that a reasonable proxy for the cost of new resources in the long-term is the BC New Resources Market Energy Curve presented in its 2012 Long-Term Resource Plan. (Exhibit B-11, pp. 16-17) The following table summarizes FortisBC's various marginal cost and LRMC values presented throughout this Application.

Table 3: FortisBC's Marginal Cost and Long-Run Marginal Cost of Energy

Definition	Value	Reference
Marginal Cost: short-term avoided costs over the 2012 to 2015 period, based primarily on avoided 3808 Energy Purchases with minor amount of market purchases and surplus sales)	$38.04 per MWh	Exhibit B-8, Commission Panel IR 7.1 Exhibit B-8, Commission Panel IR 7.2
Long-Run Marginal Cost: cost to acquire additional power through market purchases where existing resources are insufficient to meet load requirements	$84.94 per MWh	Exhibit B-8, Commission Panel IR 7.1 Exhibit B-8, Commission Panel IR 7.2

Long-Run Marginal Cost: cost to acquire additional power from new resources	$111.96 per MWh (30-year levelized value starting in 2011 using a nominal discount rate of 8 percent) $125.80 per MWh (including 11 percent losses)	Exhibit B-11, p. 17

Source: Exhibit B-11, p. 17

In the second round of Information Requests, FortisBC was asked to confirm that the LRMC set at $125.80 per MWh did not include the cost of delivery and to calculate its LRMC segmented by: 1) the energy cost (including line losses); 2) transmission delivery cost; and 3) distribution delivery cost. (Exhibit B-12, BCUC 2.9.3; BCUC 2.9.6) In response, FortisBC affirms that the plant-gate levelized value of $111.96 per MWh is the estimated required contractual price to procure energy from a newly constructed BC generation resource and the $125.80 per MWh includes line losses of 11 percent. FortisBC also confirms that the LRMC of $125.80 per MWh does not include other delivery costs, since it assumes that any incremental transmission costs would be paid directly by the project proponent or would be reflected in an adjustment to the plant-gate price paid to the project. FortisBC does not, however, indicate by how much the plant-gate price would need to be adjusted to reflect those delivery costs. (Exhibit B-12, BCUC 2.9; BCUC 2.9.6)

4.6.1 FortisBC Submission

FortisBC acknowledges that fundamentally the move to marginal cost based pricing is undertaken to set prices that lead to the most efficient use of resources and that, purely in terms of economic theory, it may not be desirable to price any electricity above the marginal cost. (Exhibit B-11, pp. 15-16) However, FortisBC submits that, given the utility's current cost structure and existing rates, pricing the Block 2 rate at LRMC fails the test of workability. Indeed, the LRMC of $125.80 per MWh is only slightly above the Block 2 rate of $0.12408 per kWh if the RIB rate as proposed by FortisBC becomes effective in 2012. An increase in the Block 2 rate of only 1.4 percent would push it beyond the LRMC. FortisBC further argues that, in order to have the LRMC cap the Block 2 rate and given the mandate to lower the Customer Charge, subsequent rate increases would impact

only the Block 1 rate, which would then rapidly lead to a convergence of the Block 1 and Block 2 rates and effectively nullify the conservation impact. In addition, FortisBC submits that residential customers are far more likely to look at the Block 1/Block 2 rate differential when making consumption-related decisions than they are to relate the Block 2 rate to any measure of LRMC. As a result, they argue conservation would be driven more by customer consideration of the rate differential than of whether the Block 2 rate is above or below the LRMC value. (FortisBC Final Submission, pp. 8-9)

In conclusion, FortisBC recommends that no cap be introduced on the Block 2 rate at this time. (FortisBC Final Submission, p. 9)

4.6.2 Intervener Submissions

BCSEA agrees that the Block 2 rate should not be capped going forward as annual revenue requirement increases would more or less quickly cause the Block 2 rate to reach the cap and the Block 1/Block 2 rate differential to begin to disappear and states that the priority should be on inducing conservation. Should the Commission choose to cap the Block 2 at the LRMC, BCSEA submits that the reference point for the Block 2 rate should be FortisBC's marginal cost of new generation and not a blended figure that includes market supply. (BCSEA Final Submission, p. 5)

BCOAPO acknowledges FortisBC's view that capping its Block 2 rate at its LRMC would result in a rapid convergence of the two block rates with dwindling conservation impacts resulting. BCOAPO further notes in its written submission:

> "... the inherent flaw in FortisBC's reasoning is that they have interpreted the purpose of this exercise as being the introduction of RIB rates and the reduction of electricity use. Instead, BCOAPO submits that RIB rates are not and should not be the overall objective, but rather a means to an end. The means is the rate structure and the end is to encourage efficient electricity use via rates that send the proper price signals to encourage customers to make the appropriate consumption decisions and this can only be achieved using a RIB rate structure when the LRMC is significantly higher than the existing rate."

This leads the BCOAPO to conclude that FortisBC is a different utility than BC Hydro with significantly different circumstances regarding rates and avoided costs. Consequently, the two utilities are not directly comparable and BCOAPO argues there is really no need for FortisBC to implement a RIB rate in order to send the proper price signals to customers, as they are coming soon, whether the utility has a RIB or not. (BCOAPO Final Submission, pp. 5-6)

Mr. Shadrack, Nelson Hydro and Strata KAS2464 do not address FortisBC's LRMC or the issue of capping the Block 2 rate in their respective Final Submissions.

4.6.3 Commission Determination

In the 2007 BC Hydro Rate Design Application Decision, the Commission acknowledged the pivotal role of conservation rates and found that conservation is the only practical way to avoid dilution of the Heritage benefit with the ever increasing reliance on high marginal cost of incremental supply (BC Hydro 2007 RDA Decision, p. 57, Order G-130-07). In the 2008 BC Hydro Residential Inclining Block (RIB) Decision, the Commission determined that the long-run cost of new supply is the appropriate referent for the Step-2 energy rate (BC Hydro 2008 RIB Decision, p. 107, Order G-124-08). The Panel finds that no new evidence has been provided in this proceeding to cause it to depart from those conclusions. **Accordingly, the Commission Panel determines that the long-run marginal cost of new supply continues to be the appropriate referent for the Block-2 energy rate.**

Should, then, the Block 2 rate be capped at the long-run marginal cost of new supply? The Panel accepts FortisBC's submission that pricing electricity above FortisBC's long-run marginal cost is not economically efficient. However, the Panel is not prepared to direct that the Block 2 rate be capped at the LRMC as proposed by FortisBC in this hearing. Table 3 above shows three different marginal costs:

1. Short-term avoided costs based on avoided Rate Schedule 3808 Energy Purchases;
2. LRMC to acquire additional power through market purchases; and

3. LRMC to acquire additional power from new resources.

While the Panel considers the most appropriate referent to be the cost of acquiring energy through new resources, we note that all of the above marginal costs represent only the cost of acquiring the energy. Thus, there is ambiguity between the LMRC as defined by FortisBC and the true long-run marginal cost of new supply to the customer. The Block 2 rate is a delivered rate, while the LRMC is a cost of acquisition – it only relates to the cost of procuring energy but does not include the LRMC of transporting that energy to customers through transmission and distribution networks. FortisBC estimates the LRMC at $125.80 per MWh, or 12.58 cents per kWh, which includes line losses of 11 percent, but does not include other delivery costs. FortisBC has provided no further information about the cost to deliver this additional energy acquired from market purchases or new resources. Accordingly, the Panel finds that there is insufficient evidence to support the position of the BCOAPO that there is "…no need for FortisBC to implement a RIB rate in order to send the proper price signals to customers."

FortisBC's proposed Block 2 rate is 12.408 cents per kWh, assuming a 2012 implementation date, which is below its estimated LRMC cost of 12.58 cents per kWh, which includes line losses but excludes other delivery costs. Thus, the Panel is satisfied that this Block 2 rate is below the actual delivered LRMC. Because of the uncertainty of the actual LRMC, the Panel does not agree that the Block 2 rate be capped at this time. **However, FortisBC is directed to provide an update of the full long-run marginal cost of acquiring energy from new resources, including the cost to transport and distribute that energy to the customer as part of the reporting to be submitted in 2014.**

4.7 Pricing Principles

Throughout this written hearing process, the term "Pricing Principle" referred to the manner in which future rate increases are applied to the Customer Charge, Block 1 rate and Block 2 rate. FortisBC's proposed Pricing Principle (Pricing Principle 1), which allows the Customer Charge to decrease over time in relation to the other RIB rate components, is as follows:

Customer Charge: exempt from revenue requirement rate increases but subject to rebalancing adjustments;

Block 1: adjusted by an amount equal to the sum of the general revenue requirement increase and any rebalancing adjustments; and

Block 2: adjusted by an amount sufficient to recover the balance of the general revenue requirement and any rebalancing adjustments.

(Exhibit B-1, p. 15)

In its Application, FortisBC also examined three alternative Pricing Principles which, together with Pricing Principle 1, are summarized in the following table.

Table 4: FortisBC's Pricing Principles Summary

Pricing Principles Summary			
	Treatment of Customer Charge	**Treatment of Block 1 Rate**	**Treatment of Block 2 Rate**
Pricing Principle 1	• Exempt from ARR* and BC Hydro flow-through Increase • Rebalancing applied	• Subject to all increases	• Calculated residually to ensure Revenue requirement is collected
Pricing Principle 2	• Exempt from ARR* and BC Hydro flow-through Increase • Rebalancing applied	• Frozen	• Calculated residually to ensure Revenue requirement is collected
Pricing Principle 3	• Subject to all increases	• Subject to all increases	• Calculated residually to ensure Revenue requirement is collected
Pricing Principle 4	• Subject to all increases	• Frozen	• Calculated residually to ensure Revenue requirement is collected
*ARR = Annual Revenue Requirement			

(FortisBC Final Submission, p. 10)

4.7.1 FortisBC Submission

FortisBC believes that its proposed Pricing Principle provides the most workable combination because Pricing Principles 3 and 4 do not result in a lowering of the Customer Charge and therefore do not comply with Commission Order G-156-10 and Pricing Principle 2 causes the Block 2 rate to escalate too quickly resulting in a block differential that is too large and unduly penalizes some customers. Thus, FortisBC submits that the Commission should approve Pricing Principle 1. (FortisBC Final Submission, p. 10)

4.7.2 Intervener Submissions

BCSEA supports FortisBC's proposed Pricing Principle 1, which it considers a middle-of-the-road approach compared to the alternatives because the Block 1 rate does not increase so quickly as to eliminate the Block 1/Block 2 rate differential and the Block 2 rate does not increase excessively. (BCSEA Final Submission, p. 5)

In its written submission, Nelson Hydro also supports FortisBC's proposed Pricing Principle. (Nelson Hydro Final Submission, p. 2) BCOAPO and Strata KAS2464 do not comment specifically on this topic. Mr. Shadrack, who proposes an entirely different RIB rate scenario in his written submission, does not comment specifically on FortisBC's proposed Pricing Principle 1.

4.7.3 Commission Determination

We have previously determined that the Customer Charge will be frozen (except for rate rebalancing increases). Pricing Principles 3 and 4 are not consistent with this approach and are not considered further. The difference between Pricing Principles 1 and 2 is that the Block 1 rate is frozen in Pricing Principle 2 and subject to all rate increases in Pricing Principle 1. Freezing the Block 1 rate will cause the differential between the two rates to increase over time. The Panel accepts FortisBC's submission that this will quickly result in a block differential that is too large and

will unduly penalize some customers. **Accordingly, the Panel directs FortisBC to apply Pricing Principle 1 to any future price increases until 2015.**

4.8 Anticipated Conservation

4.8.1 FortisBC Submission

FortisBC "is supportive of the Government's Energy Plan goal of having conservation offset 50 per cent of cumulative load growth by 2020." To this end it has proposed rate structures that encourage energy efficiency and conservation. It believes that "RIB rates can encourage customers to conserve by increasing electricity rates as consumption rises." In all the scenarios it has proposed, the price of energy consumed in the upper block is greater than the current flat rate energy price and represents a real rate increase over current charges for the consumption above the threshold. (Exhibit B-1, p. 4)

The proposals are the first step down the path to FortisBC's commitment to implementing time based conservation and efficiency rates. "FortisBC believes that the proposal for a RIB rate contained in this application is one component of a comprehensive demand reduction strategy that helps the Commission and the Province fulfill conservation goals." (Exhibit B-1, p. 8) In the Application, FortisBC defines the conservation impact of the RIB rate as "the estimated reduction in both consumption and demand that is attributable to the implementation of the given RIB rate option." (Exhibit B-1, p. 20) FortisBC later clarifies that no capacity savings were assumed for the RIB program and the only change is to FortisBC's energy requirements. (Exhibit B-5, BCUC 1.9.3, BCUC 1.17.6)

FortisBC adopts the assumption that a 1 percent change in price in the Block 1 rate will result in -0.05 to -0.20 percentage change in energy consumption and that a 1 percent change in price in the Block 2 rate will result in -0.10 to -0.30 percentage change in consumption. Based on these assumptions, the proposed two-block RIB rate, if approved, would result in estimated conservation savings in the range 1.9 percent to 5.5 percent. (Exhibit B-1, Table 7-2, p. 22)

FortisBC acknowledges the uncertainty inherent in assessing conservation impacts of the RIB rate structures but takes the position that this should not be viewed as a barrier to proceeding to choose the preferred option. FortisBC believes that based on the conservation analysis, the implementation of a RIB rate will lead to conservation behaviour on the part of those customers. (FortisBC Final Submission, p. 10)

It is clear that a RIB rate is not FortisBC's preferred approach to encouraging conservation. "The Application was filed upon the Direction provided in BCUC Order G-156-10. Of its own volition, FortisBC would not have arrived at the conclusion that a RIB rate is preferred as a method of mitigating increasing demand…The Company takes no position on the likelihood or degree to which conservation results will materialize while the RIB rate is in place and further cannot forecast annual conservation impacts with any degree of confidence." (Exhibit B-5, BCUC 1.18.1, p. 60)

Part of the uncertainty on the conservation results that can be attributed to a RIB rate is the unknown relationship between the existing DSM programs and a conservation RIB rate that would cover 99 percent of its residential customers. FortisBC believes that introducing a RIB rate may reduce DSM expenditures but DSM targets will not be affected by RIB rates. It submits that: "factors make it difficult to predict the impact of RIB on DSM programs as a whole. FortisBC expects a positive impact on DSM measures that result in significant energy savings…" (Exhibit B-5, BCUC 1.23.1), and that: "RIB and other conservation rates are not considered 'part' of PowerSense DSM…Although the goal of conservation rates is similar to PowerSense programs, the expertise required to design and implement them is different. For this reason, conservation rates have not been considered part of the PowerSense program." (Exhibit B-13, BCOAPO 2.2c) FortisBC has not indicated whether or not its DSM targets would be reviewed as a result of the implementation of a new rate structure that would cover almost all of its residential customers. Nor has it indicated whether it would initiate a new or an updated Conservation Potential Review (CPR) to assess the potential of DSM savings and therefore, new DSM targets, following implementation of the RIB rate.

With regard to conservation savings and energy efficiency from RIB rate, FortisBC is of the opinion that: "Savings would occur due to a change to a RIB rate starting with the time the rate is implemented. It may take several years for those full savings to occur due to the fact that a portion of the savings result from behavioural changes, which would be immediate, and another portion results from a change in electric-consuming devices, which occurs over time. FortisBC does not have an estimate of the savings in each year as a result of the RIB rate." (Exhibit B-6, Okanagan Environmental Industry Alliance (OEIA) 1.11.1.2)

Another source of uncertainty on conservation results is FortisBC's assumption on elasticity. FortisBC submits: "Given the uncertainty surrounding elasticity estimates and the resulting conservation forecasts, FortisBC believes a prudent and conservative approach to evaluating the efficacy of the RIB rate is to implement its preferred option, submit to the Commission its plan for monitoring and evaluating the RIB rate over the period ending December 31, 2013, and then address any program modifications that may be indicated by the resulting report." (FortisBC Final Submission, pp. 10-11) Therefore, "FortisBC … requests the Commission approve a RIB rate that includes: …The development of a plan to evaluate the conservation impact of the RIB with a reporting requirement for the period covering the date of implementation to December 31, 2013." (FortisBC Final Submission, p. 13)

4.8.2 Intervener Submissions

BCSEA supports the approval of a FortisBC RIB rate as a means to achieve conservation. However, BCSEA strongly prefers Option 7 where '90% see <10% bill impact', rather than Option 8 proposed by FortisBC where '95% see <10% bill impact', as "RIB rate designs based on the '90% see <10%'s constraint consistently induce more conservation than those based on the '95% see <10%'s constraint." (BCSEA Final Submission, pp. 1-3)

BCSEA also supports a requirement that FortisBC use a control group to enhance its evaluation of the impact of the proposed RIB rate. It submits that "…FortisBC's ability to quantify the analysis in the RIB rate application was limited by the lack of data on the elasticity of demand of FortisBC's

own customers. Using a control group in parallel with the introduction of the RIB rate is an opportunity for FortisBC to develop elasticity data for its own customers." In BCSEA's view, this opportunity should not be missed. It submits that such data would be very useful both for evaluating the RIB rate and for FortisBC's consideration of time-of-use rate designs after its Advanced Metering initiative has been implemented. (BCSEA Final Submission, p. 6)

Nelson Hydro supports "the implementation of the RIB rate as proposed by FortisBC as a means to encourage conservation. Nelson Hydro's interest in this is to monitor the outcome of this rate design to determine answers to:

- What energy consumption reductions are achieved,
- Do the consumption reductions persist or are they temporary,
- How does the rate design impact electric heat customers,
- What operating cost reductions result to the utility?"

(Nelson Hydro Final Submission, p. 3)

"BCOAPO suggests … the promotion of conservation through pricing is only appropriate where it encourages energy efficiency initiatives that cost less than new supply and if the pricing is sending signals that actually lead to cost-effective decisions." (BCOAPO Final Submission, p. 3) BCOAPO believes that "A change in focus with a greater emphasis on "cost-effectiveness" would align the objectives of FortisBC's conservation rates with its DSM programs…" (BCOAPO Final Submission, p. 3)

BCOAPO submits that there is a serious disconnect between the screening measures adopted by FortisBC in this rate design and the Bonbright Principles. (BCOAPO Final Submission, p. 4) It states that FortisBC has fundamentally erred in its screening measures by deciding that an efficient price signal is that which encourages some portion of customers to reduce consumption. This leads to FortisBC's claim that the primary goal of the RIB is to promote conservation with no consideration as to how the resulting Block rates …compare to the Utility's avoided costs (BCOAPO Final

Submission, pp. 4-5).

BCOAPO argues that "To introduce a RIB rate where both Blocks will vary from the LRMC more than the current flat rate within the short term is counterproductive because it does not promote the efficient use of electricity while causing material customer impacts…It may be a difficult pill for parties to swallow… to find that the correct action is no action at all, but that is, in BCOAPO's submission, the case here." (BCOAPO Final Submission, p. 6)

Strata KAS2464 believes the RIB rate proposal will result in only marginal conservation benefits. (Strata KAS2464 Final Submission, p. 3) It supports a requirement that FortisBC use a control group to evaluate the impact of the proposed RIB rate and disagrees with FortisBC submission that it is premature. Throughout the RIB application FortisBC did not demonstrate it understood the demands of its own customers." (Strata KAS2464 Final Submission, pp. 1-2)

Mr. Shadrack does not specifically address the linkage of the RIB rates to conservation. However, he does make several observations related to the introduction of the RIB rate, including:

- "the Commission needs to set an inclining block rate with clear hard targets and a mechanism to get there." (Shadrack Final Submission, p. 1)
- "any inclining block rate design…should allow the customer to recoup the cost of investing in energy efficient devices in a timely manner." (Shadrack Final Submission, p. 2)
- "the introduction of an inclining block rate, in and of itself, must be accompanied by clearly focused DSM programs that compliment [sic] the inclining block rate" (Shadrack Final Submission, p. 3)

4.8.3 Commission Determination

Balancing energy conservation with the Bonbright Principles is an appropriate evaluative approach by FortisBC to select the RIB rate option. While we acknowledge the submission made by BCSEA regarding Option 7's inducement of greater conservation than the proposed Option 8, we are not

persuaded that this, in itself, is sufficient to over-ride the balance of the various Bonbright Principles achieved in Option 8. In particular we have previously discussed the issues to be considered in the trade-off between bill impact and conservation**.** The Commission Panel acknowledges FortisBC's position that the conservation impact between the various options may be small enough to not have much impact on the final determination of the rate option selected. However we feel that further analysis of conservation impacts is required because of the uncertainties articulated by FortisBC.

The Panel fully supports FortisBC's intention to develop a plan to monitor and estimate the conservation impacts that can be attributed to RIB implementation. **Accordingly, the Commission Panel directs FortisBC to meet a reporting requirement covering the period from the date of implementation to December 31, 2013**. This report (the 'RIB Rate Evaluation Report') should provide FortisBC, the Commission and the Interveners the opportunity to evaluate the effectiveness of the RIB rate program, particularly with respect to its impact on conservation. In addition to including an update of the Conservation Potential Review and a report on the potential effects of interaction between RIB rates and DSM targets, the RIB Rate Evaluation Report should also address the questions raised by Nelson Hydro at page 3 of its Final Submission:

- What energy consumption reductions are achieved,
- Do the consumption reductions persist or are they temporary,
- How does the rate design impact electric heat customers, and
- What operating cost reductions result to the utility?

The RIB Rate Evaluation Report is to be submitted to the Commission by no later than April 30, 2014.

We also concur with both BCSEA and Strata KAS2464 that it is not too early to make use of a control group to enhance the evaluation of the impact of the RIB rate. **Accordingly, the Panel directs FortisBC to establish a control group in conjunction with the introduction of the RIB rate**

to develop elasticity data for its own customers. The results of this elasticity study are also to be included in the RIB Rate Evaluation Report. In this regard we note that in its Final Submission, FortisBC indicated that it works together with municipal utilities in offering demand side programs and incentives. It may be helpful if FortisBC could provide comparisons of consumption of its direct and indirect customers throughout the reporting period.

While the Commission Panel acknowledges BCOAPO's position on the desirability of understanding the linkage of conservation rates to the long-run marginal cost of electricity, we do not concur with its view that it is counterproductive to introduce a RIB rate because it does not promote the efficient use of electricity. The conservation associated with the RIB rate is, in itself, a legitimate reason for its introduction, taking account of all Bonbright Principles of pricing, not just the principle associated with efficient price signals.

4.9 Voluntary TOU rates and Mandatory RIB Rates

4.9.1 FortisBC Submission

As noted in Section 4.8.1, it is clear that a RIB rate is not FortisBC's preferred approach to encouraging conservation. Submissions of FortisBC from the Application and the IR process include:

- "The consensus reached during the public consultation, and the preference of FortisBC, was for maintaining the status quo pending the AMI implementation (Exhibit B-1, p. 13)
- "FortisBC does not believe that the implementation of a RIB rate eases the introduction of time based rates. The Company further believes that the interim nature of the RIB rate, being effective between the current flat rate and the implementation of any time-based rates will create difficulties for the transition. FortisBC is concerned that customer confusion may result from the implementation of the two types rate types in fairly quick succession." (Exhibit B-5, BCUC 1.4.3)
- "FortisBC believes that time based rates provide conservation benefits which are at a minimum as good as a RIB rate while simultaneously providing customers with more of an opportunity to conserve, thus reducing their total cost of electricity." (Exhibit B-5,

BCUC 1.6.3,) "FortisBC believes that the primary goal of time-based rates is to conserve capacity, but that energy conservation also occurs." (Exhibit B-12, BCUC 2.4.1)

FortisBC submits that time-based conservation rates offer the best alternatives to flat rates for FortisBC and its customers. It is currently FortisBC's intention to introduce some suite of time-based rates to complement the RIB rates, likely on a voluntary participation basis, if a RIB rate is mandated by the Commission. (Exhibit B-5, BCUC 1.6.4) However, despite this reservation, FortisBC states that the implementation of the RIB rate is a stand-alone program and that the eventual move to time-based rates does not feature as a consideration in any of the work done to date." (Exhibit B-6, OEIA 1.5.1)

The RIB rate Application has not changed FortisBC's intention regarding the implementation of Advanced Metering Infrastructure and time based rates although those rates are now expected to be optional rather than mandatory (Exhibit B-6, OEIA 1.8.4.1). FortisBC states that "in due course" it will consider a rate structure that combines time-based and RIB principles, but believes that such a rate structure is overly complex to customers (Exhibit B-13, BCSEA 2.31.1) At this juncture, FortisBC has not yet completed any detailed analysis on the effects of wide-scale time based rates that could be implemented after an Advanced Metering Infrastructure was implemented, and therefore it cannot state conclusively as to whether TOU rates can achieve better conservation than RIB rate. (Exhibit B-8, BCUC IR 1.5.2, p. 20)

4.9.2 Intervener Submissions

Mr. Russell Work is opposed to the proposal to implement the RIB rate, as he believes that "it will have minimal impact on energy conservation." (Exhibit B-6, Work IR 1, p. 1) He argues for promoting TOU metering but provided no evidence on the benefits of doing so. No other Intervener addressed the relative merits of a voluntary TOU rate and mandatory RIB rates or provided any submission on combining RIB and TOU rates.

4.9.3 Commission Determination

FortisBC refers to the "interim nature" of the RIB rate, being effective between the current flat rate and the implementation of any time based rates. The Commission Panel cautions FortisBC against concluding that the RIB rate is only temporary in nature, particularly in view of not yet having made application for its AMI initiative, nor for any TOU rates associated with it. The RIB rate could well be an integral part of a longer-term conservation initiative and should be designed with that in mind, including the approaches used to measure and manage its ongoing efficacy.

In its submission, FortisBC proposes that: "Customers who choose to take service under FortisBC's existing conservation rate, Time-of-Use billing, would not be compelled to move to the RIB rate." The Panel acknowledges the difficulties of applying the RIB rate to these customers and accordingly **directs that customers currently receiving service under Time-of-Use billing will not be charged at the RIB rate until and unless these customers elect to move from TOU billing to RIB rate billing. However, the Panel directs FortisBC to apply the RIB rate on a mandatory basis to all residential customers not currently receiving service under TOU billing.**

If FortisBC moves forward with its Advanced Metering Initiative as it currently plans to do, it will need to develop a strategy to integrate the RIB rate regime with its TOU rate regime. If this is accomplished during the reporting requirement period, there will be an opportunity to include the effect of combined TOU and RIB rates on conservation in the RIB Evaluation Report. **The Panel directs FortisBC to consider effective ways to report this information and include the results in the RIB Rate Evaluation Report.**

4.10 Indirect Customers

On October 27, 2011, the Commission Panel requested that the parties address in their Final Submissions the following questions:

1. Should the Panel consider the implications of conservation rate setting for indirect customers of FortisBC in this proceeding?
2. Should the Panel consider the implications of conservation rate setting for these indirect customers in future FortisBC rate design proceedings?

(Exhibit A-22)

4.10.1 FortisBC Submission

FortisBC submits that whether or not the Commission "should" have these considerations is a matter of provincial policy "best left to the Commission and government to determine." FortisBC further submits that if the questions are rephrased to inquire as to whether the Commission "can" directly influence rates of indirect customers in the current regulatory environment, then FortisBC's answer is "no" to the two questions. FortisBC states that electric utilities who are direct customers of FortisBC, as a Wholesale customer class, set their own rates for their customers, and are not regulated by the Commission. FortisBC also submits: "The Commission may consider the implications of conservation rate setting for FortisBC direct customers, including those rates for wholesale municipal electric utilities; however the Commission cannot consider the implications of conservation rate setting for FortisBC indirect customers." (FortisBC Final Submission, p. 12)

FortisBC further submits that: "Municipal electric utilities who are direct customers of FortisBC (Wholesale customer class) set their own rates for their customers, and are not regulated by the Commission in doing so other than if operating outside municipal boundaries. The definition of 'public utility' in the *Utilities Commission Act* excludes 'a municipality or regional district in respect of services provided by the municipality or regional district within its own boundaries'."

FortisBC also acknowledges that these five municipal utilities' residential customers, though indirect, do, in aggregate, comprise a significant portion of FortisBC's load. These indirect residential customers will not be subject to a conservation rate.

FortisBC submitted the 'Residential End Use Survey' which "took into account responses from indirect customers of FortisBC because the purpose of the Survey was in part to assist FortisBC in forecasting future electrical demand and in designing demand side management programs." (FortisBC Final Submission, p. 12)

4.10.2 Intervener Submissions

BCSEA also submits that the Panel should not consider the implications of conservation rate setting for indirect customers in this proceeding. BCSEA further notes that it has insufficient information to comment on the consideration of implications on indirect customers of future rate design applications by FortisBC. (BCSEA Final Submission, p. 6)

Nelson Hydro responded to the first of the above questions with the comment: "No…. we note that broadening the scope to include customers of other utilities could require a substantive repeat of the process." In response to the second question, it submitted: "No. In BC there are eight distinct electrical utilities and the proceedings for one should not spill over into the others. Some of these utilities do not require BCUC approval for their rate setting." (Nelson Hydro Final Submission, p. 1)

4.10.3 Commission Determination

The Panel agrees with the submissions of the parties, but notes that five of FortisBC's wholesale customers: the Cities of Kelowna, Grand Forks, Nelson, Penticton and Summerland all have a significant component of residential ratepayers. In this regard, the Panel also notes that FortisBC and municipal utilities work together in offering demand side programs and incentives and this cooperative approach to DSM is mutually beneficial.

Accordingly, we question why FortisBC should not work together with these municipal utilities to assist them to implement a RIB rate for their own residential customers as part of a demand side management program. As FortisBC gains experience with its own RIB rate, and if it can demonstrate customer acceptance and conservation savings, it will be in a better position to assist

its wholesale customers with their own RIB rates, should they choose to go that route.

FortisBC could also consider a two-tier conservation rate for its Wholesale customers. In this regard, the Panel refers to a recent Commission Decision concerning the resolution of a complaint filed by Zellstoff Celgar Limited Partnership regarding the failure of FortisBC to complete a general service agreement and FortisBC's application of RS 31 demand charges. (Celgar Complaint Decision, Order G-188-11) In that Decision, FortisBC was directed to submit an application to the Commission by May 31, 2012 for a two-tier stepped transmission rate to reflect conservation objectives. FortisBC was further directed to consult with all classes of its customers to determine guidelines for the level of non-Power Purchase Agreement embedded cost of power to which eligible self-generation customers should be entitled.

The Panel is of the opinion that ideally, all of FortisBC's customers, including Wholesale customers, should be charged a rate that reflects conservation objectives. Accordingly, after introduction of inclining block rates for its residential customers, FortisBC should consider the implementation of two-tier rates for its wholesale customers. **In particular, the Panel directs FortisBC, as part of its RIB Rate Evaluation Report, to provide an analysis of the potential effect of a two-tier wholesale rate on the consumption of its wholesale customers.**

5.0 SUMMARY OF COMMISSION PANEL DETERMINATIONS

In this decision, the Panel has provided a number of directives. These are summarized below:

1. **FortisBC is directed to implement a RIB rate, which consisting of four components: a Customer Charge, a threshold, and two block rates, set at the following values, based on May 1, 2011 rates:**

    - **A Customer Charge of $28.93 per billing period;**
    - **A threshold set at 1,600 kWh per billing period;**
    - **A Block 1 rate of 7.828 cents per kWh; and**
    - **A Block 2 rate of 11.272 cents per kWh.**

2. **FortisBC is to implement this RIB rate as soon as is reasonably practicable and by no later than July 31, 2012. FortisBC is to file a revised Tariff Sheet for Rate Schedule 01, no later than 30 days prior to the date the RIB rate becomes effective.**

3. **FortisBC is directed to apply Pricing Principle 1 to future rate increases for the years 2012 to 2015. Specifically:**

    a. **The Customer Charge is exempt from general rate increases, other than rate rebalancing increases;**

    b. **The Block 1 rate is subject to general and rebalancing rate increases; and**

    c. **The Block 2 rate is increased by an amount sufficient to recover the remaining required revenue (i.e., the residual rate).**

4. **FortisBC is directed to apply the RIB rate on a mandatory basis to all residential customers with the exception of those taking service at a Time of Use rate at the time this Decision is issued.**

5. **FortisBC is directed to file a RIB Rate Evaluation Report (Report), covering the period from the date of implementation to December 31, 2013. The Report should provide the utility, the Commission and the interveners the opportunity to evaluate the effectiveness of the RIB rate program, in particular with respect to its impact on conservation. The RIB Rate Evaluation Report is to include, but not be limited to, the following:**

    a. **The energy consumption reductions achieved;**
    b. **Whether the consumption reductions persist or are temporary;**
    c. **How the rate design impacts electric heat customers; and**
    d. **The resulting operating cost reductions to the utility.**

    The Report should also include an in-depth analysis of the full long-run marginal cost to acquire energy from new resources, including the long-run marginal cost to transport and distribute that energy to the customer, and how that cost compares to the Block 2 rate; the combined effect of integrating TOU and RIB rates on the conservation achieved by the RIB, should that information be available; an update of the Conservation Potential Review and report on the potential effects of interaction between RIB rates and DSM targets; comparison of energy usage of indirect customers with the energy usage of direct customers; and an analysis of the potential effect of a two-tier wholesale rate on the consumption of its wholesale customers. The Report is to be filed with the Commission by no later than April 30, 2014.

6. **FortisBC is directed to establish a control group in conjunction with the introduction of the RIB rate to develop elasticity data for its own customers. The results of this elasticity study are to be included in the RIB Rate Evaluation Report.**

DATED at the City of Vancouver, in the Province of British Columbia, this 13th day of January 2012.

D. MORTON
PANEL CHAIR

L.A. O'HARA
COMMISSIONER

M.R. HARLE
COMMISSIONER

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-3-12

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Inc.
for Approval of a Residential Inclining Block Rate

BEFORE: D. Morton, Panel Chair/Commissioner
L.A. O'Hara, Commissioner
M.R. Harle, Commissioner

January 13, 2012

O R D E R

WHEREAS:

A. On March 31, 2011, FortisBC Inc. (FortisBC) filed an application for approval of a Residential Inclining Block (RIB) Rate (Application) to the British Columbia Utilities Commission (Commission) pursuant to sections 58 to 61 of the *Utilities Commission Act*;

B. The Application proposes to implement a default mandatory RIB rate for FortisBC's residential customers. The RIB rate is composed of a Customer Charge and two rate blocks separated by a threshold level of consumption of 1,600 kWh per two-month billing period;

C. The Application examines 18 options. The option proposed by FortisBC has the Block 1 and Block 2 rates set at levels such that 95 percent of customers will experience annual bill impacts of less than 10 percent;

D. FortisBC proposes to exempt the Customer Charge from future rate increases, other than those related to rebalancing through 2015, effectively reducing the Customer Charge relative to the other billing determinants. FortisBC also proposes to apply future general revenue requirement rate increases as follows:

   1) Block 1 rate would be increased by an amount equal to the sum of the general revenue requirement increase and any rebalancing adjustments; and

   2) Block 2 rate would be calculated residually to recover the balance of the general revenue requirement and any rebalancing adjustments;

E. FortisBC proposed that the Application be reviewed through a written hearing process, including only one round of Information Requests (IRs) and concluding on June 15, 2011 by way of its Reply Submission. Based on this Regulatory Timetable, FortisBC anticipated the RIB rate structure to become effective January 1, 2012;

F. The Application was reviewed through a written hearing process. The Regulatory Timetable was revised a number of times and ultimately included:

- One round of IRs from Commission staff and Interveners;
- One round of IRs from the Commission Panel;
- A Procedural Conference held in Vancouver on August 3, 2011 to consider, among other matters, whether FortisBC had filed sufficient evidence to enable the evaluation of the Application, and whether the Application should proceed with an oral or written hearing;
- The filing by FortisBC of additional evidence on August 24, 2011 to clarify, among other issues, how 2012 RIB rates are to be calculated, the value of the long-run marginal cost, elasticity and conservation measures, and the customer charge calculated on a cost of service basis;
- An additional round of IRs from Commission staff and Interveners; and
- The filing of evidence by Interveners;

G. The Commission has reviewed the Application and the material submitted through the written hearing process.

NOW THEREFORE the Commission, for the reasons set out in Decision issued concurrently with this Order, determines as follows:

1. FortisBC is directed to implement a RIB rate consisting of four components: a Customer Charge, a threshold and two block rates, set at the following values, based on May 1, 2011 rates:

    a. A Customer Charge of $28.93 per billing period;
    b. A threshold set at 1,600 kWh per billing period;
    c. A Block 1 Rate of 7.828 cents per kWh; and
    d. A Block 2 Rate of 11.272 cents per kWh.

2. FortisBC is to implement this RIB rate as soon as is reasonably practicable, and by no later than July 31, 2012. FortisBC is to file a revised Tariff Sheet for Rate Schedule 01, no later than 30 days prior to the date the RIB rate becomes effective.

3. FortisBC is directed to apply Pricing Principle 1 to future rate increases for the years 2012 to 2015. Specifically:

    a. The Customer Charge is exempt from general rate increases, other than rate rebalancing increases;
    b. The Block 1 rate is subject to general and rebalancing rate increases; and
    c. The Block 2 rate is increased by an amount sufficient to recover the remaining required revenue (*i.e.*, the residual rate).

4. FortisBC is directed to apply the RIB rate on a mandatory basis to all residential customers with the exception of those taking service at a Time-of-Use (TOU) rate at the time this Decision is issued.

5. FortisBC is directed to provide a RIB Rate Evaluation Report (Report) covering the period from the date of implementation to December 31, 2013. This Report should provide the utility, the Commission and Interveners the opportunity to evaluate the effectiveness of the RIB program, in particular with respect to its impact on conservation. The Report is to include, but not be limited to, the following:

    a. The energy consumption reductions achieved;
    b. Whether the consumption reductions persist or are temporary;
    c. How the rate design impacts electric heat customers; and
    d. The resulting operating cost reductions to the utility.

    The Report should also include an in-depth analysis of the full long-run marginal cost of acquiring energy from new resources, including the long-run marginal cost to transport and distribute that energy to the customer, and how that cost compares to the Block 2 rate; the combined effect of integrating TOU and RIB rates on the conservation achieved by the RIB, should that information be available; an update of the Conservation Potential Review and report on the potential effects of interaction between RIB rates and Demand Side Management targets; comparison of energy usage of indirect customers with the energy usage of direct customers; and an analysis of the potential effect of a two-tier wholesale rate on the consumption of its wholesale customers. This Report should be submitted to the Commission no later than April 30, 2014.

6. FortisBC is directed to establish a control group in conjunction with the introduction of the RIB rate to develop elasticity data for its own customers. The results of this elasticity study are to be included in the RIB Rate Evaluation Report.

DATED at the City of Vancouver, in the Province of British Columbia, this 13th day of January 2012.

BY ORDER

D. Morton
Panel Chair/Commissioner

THE REGULATORY PROCESS

FortisBC filed the RIB rate application on March 31, 2011. By Order G-68-11the Commission established an Initial Regulatory Timetable for the review process. (Exhibit A-2)

Due to the limited interest expressed by parties for the Procedural Conference scheduled for May 10, 2011, the Commission Panel decided to cancel that proceeding and requested written submissions on the procedural matters. (Exhibit A-3)

On May 20, 2011, after reviewing the written submissions by parties the Commission Panel established a written hearing process and issued a revised Regulatory Timetable by Order G-94-11 which included two rounds of Information Requests (IRs). (Exhibit A-7)

In response to some technical issues raised by Commission Staff during the review process FortisBC indicated that it had identified a discrepancy in some of the information presented in the RIB application. Accordingly, the Commission Panel suspended the Regulatory Timetable pending FortisBC's proposed update. (Exhibit A-10, Exhibit A-11)

In response to the June 27, 2011 filing of FortisBC's Errata No. 3 (Exhibit B-1-2), the Commission Panel issued its own IR to FortisBC on July 8, 2011. (Exhibit A-12)

In reference to FortisBC's responses to the Panel IR, Mr. Shadrack's IR, and to the issues of simplification and a convenient comparison of RIB rate options raised by BCSEA, the Commission Panel convened a Procedural Conference for August 3, 2011 in Vancouver. (Exhibit A-15) Specifically, the Panel was seeking submissions from the participants on whether there was sufficient evidence on the record to introduce a RIB rate and whether the hearing of the Application by way of a written hearing process remains preferable to an oral hearing process. (Exhibit A-15)

Following the Procedural Conference the Panel, by Order G-142-11, directed FortisBC to file additional evidence as described in the Reasons for Decision on or before August 24, 2011. FortisBC was also directed to ensure that all evidence that is filed is accurate. (Appendix A-17)

By Letter L-84-11 the Commission Panel confirmed that the hearing will continue to proceed as a written hearing and established a revised Regulatory Timetable leading to the completion of the evidentiary record by November 21, 2011. (Exhibit A-20)

The only Intervener filing Intervener Evidence was Mr. Shadrack.

On October 27, 2011, the Commission Panel requested submissions regarding conservation rates for indirect customers of FortisBC. ((Exhibit A-22)

Final Submissions were filed by FortisBC and Interveners on November 4, 2011 and November 14, 2011 respectively, with a reply Submission of FortisBC filed on November 21, 2011.

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Inc.
Residential Inclining Block Rate Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated April 6, 2011 – Appointment of Panel
A-2	Letter dated April 12, 2011 and Order G-68-11 - Establishing an initial Regulatory Timetable and Procedural Conference
A-3	Letter dated May 5, 2011 - Cancellation of Procedural Conference
A-4	Letter dated May 9, 2011 – Commission Staff response to Exhibit C10-2
A-5	Letter dated May 11, 2011 – Commission Information Request No. 1
A-6	Letter dated May 12, 2011 – Amended Initial Regulatory Timetable
A-7	Letter dated May 20 – Revised Regulatory Timetable and Reasons for Decision
A-8	Letter dated May 20 – Response to WR regarding Exhibit C15-2
A-9	Letter dated May 30 – Correction to the Regulatory Timetable
A-10	Letter dated June 21, 2011 – Possible amendment to the current Regulatory Timetable
A-11	Letter dated June 24, 2011 - Suspension of Regulatory Timetable
A-12	Letter L-55-11 dated July 8, 2011 – Commission Panel Information Requests
A-13	Letter dated July 12, 2011 – Clarification regarding Suspension of Regulatory Timetable
A-14	Letter dated July 13, 2011 – Clarification regarding Interveners Information Request No. 2
A-15	Letter Dated July 25, 2011 – Procedural Conference

Exhibit No.	Description
A-16	Letter Dated July 25, 2011 – Order of Appearances for Procedural Conference on August 3, 2011
A-17	Letter Dated August 10, 2011 and Order G-142-11 – Revised Regulatory Timetable
A-18	Letter Dated August 15, 2011 –Clarification – Order G-142-11
A-19	Letter Dated September 8, 2011 –Commission Information Request No. 2
A-20	Letter Dated October 14, 2011 – Commission Letter L-84-11 Revised Regulatory Timetable
A-21	Letter Dated October 20, 2011 –Commission Information Request No. 1 to Intervener Mr. Andy Shadrack
A-22	Letter Dated October 27, 2011 – Commission Request for Comments from Applicant and Interveners in Final Submissions
A-23	Letter Dated November 21, 2011 – Response on Late Final Submission
A2-1	Letter Dated May 11, 2011 – Commission Staff filing British Columbia Hydro and Power Authority – 2008 Residential Inclining Block Rate – Appendix C, Utility Survey Results
A2-2	Letter Dated May 11, 2011 – Commission Staff filing Regulation of the Minister of Ministry of Energy, Mines and Petroleum Resources – Ministerial Order No. M 271 dated November 6, 2008 – Demand-Side Measures
A2-3	Letter Dated October 19, 2011 – Email exchange between BCUC Staff and FortisBC Inc. (Michael Leyland) confirming FortisBC's residential rates from January 2005 to October 2011

APPLICANT DOCUMENTS FORTISBC INC.

B-1	**FORTISBC INC. (FBC)** Letter dated March 31, 2011- Filing Residential Inclining Block Rate Application
B-1-1	Letter dated June 7, 2011 – FBC Submitting Errata No. 1 to the Application
B-1-2	Letter dated June 27, 2011 – FBC Submitting Errata No. 3 to the Application including responses to BCUC IR 1 and responses to BCOAPO IR1

Exhibit No.	Description
B-2	Letter dated April 6, 2011- FBC Submitting comments on NH (C2-1) letter regarding proposed regulatory agenda
B-3	Letter dated May 9, 2011 – FBC Submitting comments on proposed process
B-4	Letter dated May 13, 2011 – FBC Reply submissions on Proposed Process
B-5	Letter dated June 7, 2011 – FBC Submitting Responses to BCUC Information Requests No. 1
B-5-1	Letter dated June 17, 2011 – FBC Submitting Erratum No. 2 to its Responses to Commission Information Requests No. 1
B-6	Letter dated June 7, 2011 – FBC Submitting Responses to Interveners Information Requests No. 1
B-7	Letter dated July 14, 2011 – FBC Submitting Response to BCUC Letter L-55-11
B-8	Letter dated July 22, 2011 – FBC Responses to BCUC IRs on Errata 3
B-9	Letter dated July 29, 2011 – FBC Submitting Errata to IR No.1 from BCUC and TR
B-10	Letter dated August 2, 2011 - FBC Submitting responses to Exhibit A-15
B-10-1	Letter dated August 4, 2011 - FBC Submitting corrected spreadsheet
B-11	Letter dated August 24, 2011 - FBC Submitting Additional Evidence
B-12	Letter dated September 29, 2011 – FBC Responses to BCUC IR No. 2
B-13	Letter dated September 29, 2011 – FBC Responses to Intervener IRs No. 2

INTERVENER DOCUMENTS

C1-1	**TARNOFF, RICHARD (TR)** Online Registration dated April 4, 2011– Request for Intervener Status by Richard Tarnoff
C1-2	Letter dated May 14, 2011 Via Email – TR Submitting Information Request No. 1
C1-3	Letter dated July 31, 2011 – TR Submitting comments regarding Basic Charge
C1-4	Letter Dated September 8, 2011 Via Email – TR Submitting IR No. 2

Exhibit No.	Description
C2-1	**NELSON HYDRO (NH)** Letter dated April 5, 2011- Submitting comments regarding proposed regulatory agenda
C2-2	Letter dated May 11, 2011 – NH Submitting comments on procedural matters
C2-3	Letter dated May 16, 2011 – NH Submitting Information Request No. 1
C2-4	Letter Dated September 8, 2011 Via Email – NH Submitting IR No. 2
C3-1	**OKANAGAN ENVIRONMENTAL INDUSTRY ALLIANCE (OEIA)** Online Registration dated April 14, 2011 - Request for Intervener Status by Ludo Bertsch
C3-2	Letter dated May 10, 2011 – OEIA Submitting comments on procedural matters
C3-3	Letter dated May 16, 2011 – OEIA Submitting Information Request No. 1
C4-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Online Registration dated April 14, 2011 - Request for Intervener Status by Joanna Sofield
C5-1	**BRITISH COLUMBIA OLD AGE PENSIONERS ORGANIZATION ET AL (BCOAPO)** Email Registration dated April 15, 2011 – Request for Intervener Status by Jim Quail
C5-2	Letter dated May 10, 2011 – BCOAPO Submitting comments on proposed process
C5-3	Letter dated May 13, 2011 – BCOAPO Submitting Information Request No. 1
C5-4	Letter dated June 28, 2011 – BCOAPO Submitting Information Request No. 2
C5-5	Letter dated August 3, 2011 - BCOAPO Submitting notice of Counsel change
C5-6	Letter Dated September 8, 2011 Via Email – BCOAPO Submitting IR No. 2
C6-1	**CITY OF KELOWNA** Email Registration dated April 19, 2011 – Request for Intervener Status by Cindy McNeely
C7-1	**GABANA, NORMAN (GN)** Email Registration dated April 21, 2011 – Request for Intervener Status
C7-2	Letter dated May 9, 2011 – GN Submitting comments on proposed process
C7-3	Letter dated May 15, 2011 Via Email – GN Submitting Information Request No. 1
C8-1	**RAJAPAKSHE, RASIKA** Email Registration dated April 25, 2011 – Request for Intervener Status

Exhibit No.	Description
C9-1	**SHADRACK, ANDY (SA)** Email Registration dated April 26, 2011 – Request for Intervener Status
C9-2	Letter dated May 9, 2011 – SA Submitting comments on proposed process
C9-3	Letter dated May 11, 2011 Via Email – SA Submitting comments on Oral Hearing
C9-4	Letter dated May 12, 2011 Via Email – SA Submitting Information Request No. 1
C9-5	Letter dated May 16, 2011 Via Email – SA Submitting Additional Information Request No. 1
C9-6	Letter dated June 12, 2011 Via Email – SA Request for extension
C9-7	Letter dated June 16, 2011 Via Email – SA Submitting comments regarding IR No. 1 responses
C9-8	Letter dated June 21, 2011 Via Email – SA Submitting response to Exhibit A-10
C9-9	Email dated July 8, 2011 – SA Submitting Late Information Request No. 2
C9-10	Email dated July 16, 2011 – SA Comment regarding FBC Information Request No. 1 Responses
C9-11	Letter dated July 28, 2011 Via Email – SA Submitting comments
C9-12	Letter Dated September 8, 2011 – SA Submitting Information Request No. 2
C9-13	Letter Dated October 13, 2011 Via Email – SA Submitting Evidence
C9-14	Letter Dated October 13, 2011 Via Email – SA Submitting Response to Commission Information Request No. 1
C10-1	**STRATA CORPORATION KSA2464 (SCK)** Email Registration dated April 26, 2011 – Request for Intervener Status by Henry Stanski and John Loewen
C10-2	Letter dated May 5, 2011 Via Email – SCK Submitting comments on Application
C10-3	Letter dated May 9, 2011 Via Email – SCK Response to Exhibit A-3
C10-4	Letter dated May 15, 2011 Via Email – SCK Submitting further comments on Application
C10-5	Letter dated May 23, 2011 - SCK Additional Comments and Questions #2

Exhibit No.	Description
C10-6	Letter dated July 11, 2011 – SCK Comments and Information Request No. 2
C10-7	Letter dated July 31, 2011 – SCK submissions regarding A-15
C11-1	**B.C. SUSTAINABLE ENERGY ASSOCIATION (BCSEA)** Web Registration dated April 28, 2011 – Request for Intervener Status by William J. Andrews
C11-2	Letter dated May 10, 2011 – BCSEA Submitting comments on procedure
C11-3	Letter dated May 16, 2011 – BCSEA Submitting Information Request No. 1
C11-4	Letter dated July 12, 2011 – BCSEA Submitting Information Request No. 2
C11-5	Letter Dated September 8, 2011 Via Email – BCSEA Submitting IR No. 2
C12-1	**SLACK, BURYL** Facsimile Registration dated April 30, 2011 – Request for Intervener Status
C13-1	**IRRIGATION RATEPAYERS GROUP (IRG)** Dated May 4, 2011 - Request for Intervener Status by Fred Weisberg
C14-1	**KOOTENAY TAX PAYERS ASSOCIATION (KTPA)** Dated May 4, 2011 - Request for Intervener Status by Josh Smienk
C14-2	Letter dated May 4, 2011 – KTPA Submitting request to register for the procedural conference
C15-1	**WORK , RUSSELL (WR)** Letter Dated May 4, 2011 Via Email and Online Registration - Request for Late Intervener Status by Russell Work
C15-2	Letter submitted May 19, 2011 – WR Submitting Information Request No. 1

LETTERS OF COMMENT

E-1	Mersereau, Brent - Letter of Comment dated April 25, 2011 Via Email
E-2	Marty, Maurice - Letter of Comment dated July 31, 2011