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March 29, 2018

VIA ELECTRONIC MAIL

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

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

Dear Sirs/Mesdames:

Re: FortisBC Inc. ("FBC") 2017 Cost of Service Analysis and Rate Design Application ~ Project No. 1598939

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

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

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

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

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA

INFORMATION REQUEST NO. 1 TO FORTISBC INC.

FortisBC Inc. – 2017 Cost of Service Analysis and Rate Design Application
Project No. 1598939

March 29, 2018

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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.

In alignment with the Minister's letter, FBC has considered bill impacts for customers in a variety of circumstances along with the traditional rate design principles discussed in Section 3.2. The Company's proposals for residential rates are discussed in Section 6.1.4 of this Application.

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.

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.

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.

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.

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.

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

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

2.2.2 If no, please explain why not.

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

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.

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.

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.

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

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

2.4.2 If no, please explain why not.

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.

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.

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.

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.

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.

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

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

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.

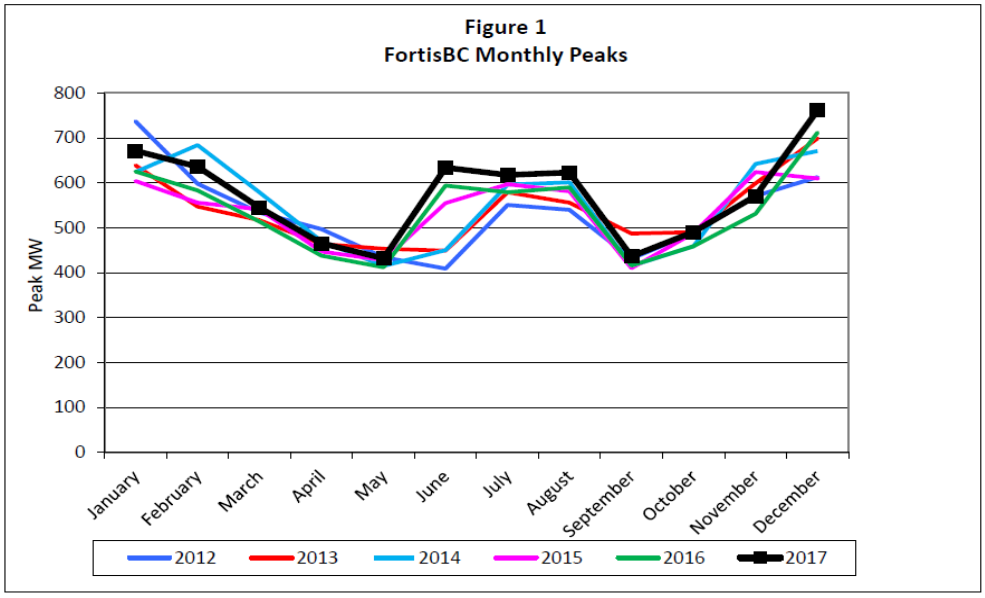
6.1 Please provide a quantitative assessment of the impact that net metering has on other customers at this time.

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.

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.

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

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.

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.

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

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'.

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.

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.

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.

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

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

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.

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?

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

10.4 Does FBC functionalize DSM costs to its customers?

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

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

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

10.6 Please describe RS 37 service and customers.

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.

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

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

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

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

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.

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.

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.

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.

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

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.

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.

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

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?

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.

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

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.

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

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

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

16.3.1 If yes, please provide the results.

16.3.2 If no, please explain why not.

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?
17.1.1 If so, please identify.

17.2 Is FBC aware of any other utilities that use a 2CP allocator?
17.2.1 If so, please provide a list of other that utilities utilize a 2CP allocator.

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.

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.

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.

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

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

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.

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.

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

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.

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.

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.

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

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

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.

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.

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.

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.

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.

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'?

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

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

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.

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?

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.

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.

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?

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

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

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.

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.

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?

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

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?

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

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.

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

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.

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.

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

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

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.

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.

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.

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				

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

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

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.

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.

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

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.

37.1.1 If not confirmed, please provide Table 9-6

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.

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				

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

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

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] 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.

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?

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.

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.
40.2 Please provide the 2015 Decision that resulted in approval of RS 37 and its rates.
40.3 Please confirm that FBC did not conduct a cost of service analysis at this time.
40.4 Please provide a cost of service analysis for RS 37 on the basis used in the application.

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.

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%?

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.

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.

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.

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.

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.

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

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.

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

46.3 Why is FBC eliminating he Reserved capacity charge?

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

46.5 Please provide the % recovery of the Customer charge.

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

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.