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FortisBC Inc.

2017 Cost of Service Analysis and Rate Design Application

Decision
and Order G-40-19

February 25, 2019

Before:
D. A. Cote, Panel Chair
R. I. Mason, Commissioner
D. M. Morton, Commissioner

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Executive Summary

FortisBC Inc. (FBC) filed its 2017 Cost of Service Analysis (COSA) and Rate Design Application (RDA) on December 22, 2017 (Application). Prior to this Application, FBC and its predecessors have filed three major rate design applications with the British Columbia Utilities Commission (BCUC) – in the years' 1983, 1997 and 2009. The current Application contains FBC's 2017 COSA study, proposals for rate rebalancing of certain rate classes, rate design proposals for residential, commercial, irrigation, wholesale and transmission services rate classes, a proposal to re-open the residential optional Time of Use (TOU) rate and to revise all other optional TOU rates, and proposed amendments to FBC's Electric Tariff and General Terms and Conditions.

The context for the Panel's review of FBC's rate design proposals consists of (1) the legal framework as set out in sections 58 to 61 of the *Utilities Commission Act*; (2) accepted rate design principles identified by Dr. James C. Bonbright; (3) the *Clean Energy Act*; (4) FBC's regulatory history, including the 2011 Residential Inclining Block (RIB) Rate Design Decision; and (5) BC Government direction.

The review process for the Application included a procedural conference, two rounds of information requests (IRs) and responses, intervener submissions of evidence, IRs and responses to the intervener evidence, and written final and reply arguments.

In this Decision, the Panel makes the following findings and determinations.

2017 Cost of Service Analysis Study

The Panel finds the 2017 COSA Study results reasonable and accepts the 2017 COSA Study as the basis for FBC's rate rebalancing and rate design proposals. Overall, the method and results of the 2017 COSA Study are consistent with FBC's previous COSA study, and the approach reflects cost causation. The Panel acknowledges there is a certain degree of judgment that must be applied when conducting a COSA study which can lead to more than one option for treatment of certain items. In these cases, FBC has provided adequate reasoning and evidence to support its chosen treatment.

A number of issues were raised by interveners regarding the 2017 COSA Study, including the following:

- Use of the Minimum System Study (MSS) method combined with the Peak Load Carrying Capability (PLCC) adjustment to classify distribution costs.
- FBC's approach of applying Rate Schedule (RS) 37 revenues as an offset to the overall revenue requirement.
- The treatment of Generation-Related Transmission Assets and Demand-Side Management (DSM) Costs within the 2017 COSA Study.
- Use of the 2 Coincident Peak (CP) allocator to allocate production and transmission rate base.

In each of the above cases, the Panel finds FBC's proposed approach reasonable and therefore declines to take any of the actions requested by interveners.

Rate Rebalancing

The Panel directs FBC to rebalance the Lighting customer class (RS 50) and the Large Commercial Transmission customer class (RS 31) as follows: rebalance RS 50 to achieve a revenue-to-cost ratio of 100 percent and allocate the resulting revenues to RS 31.

The Panel directs FBC to file with the BCUC a Cost of Service study by no later than December 31, 2020. We are concerned that the R/C ratios will move outside the range of reasonableness before FBC's next planned rate design application, and a cost of service study in 2020 will provide the opportunity for a further rebalancing before customer classes move too far outside the range of reasonableness.

Fixed Cost Recovery

A key proposal within the Application is FBC's request to change the rate structure of all applicable customer classes to achieve a minimum fixed cost recovery of 55 percent of customer-related costs and a minimum fixed cost recovery of 65 percent of demand-related costs.

The Panel approves FBC's proposals for rate changes to the fixed Customer and Demand Charges for all rate classes as outlined in the Application. The Panel notes that the changes FBC is proposing will be revenue neutral and are primarily designed to better match customer costs on a cost causation basis and allow for a greater portion of fixed costs to be recovered through fixed charges rather than those that are volumetric.

The Panel also approves FBC's proposal to phase in the customer charge for residential customers. With respect to a phase-in of RS 21 changes as proposed by the CEC, the Panel agrees and directs FBC as part of its compliance filing to provide a proposal outlining a phase-in option of up to three years for those RS 21 customers that have been identified as having a bill impact greater than 10 percent as a result of changes to fixed charges.

Flattening of the Residential Rate

In the FBC 2011 RIB Rate Decision, the BCUC directed FBC to implement a two-tier inclining block rate for residential customers. This rate is referred to as the Residential Conservation Rate (RCR). In the current Application, FBC proposes to decrease the differential between the Tier 1 and Tier 2 rates such that after a period of five years the differential between the Tier 1 and Tier 2 rates will be zero, resulting in a flat rate.

The Panel approves FBC's Application to switch to a flat rate for residential customers and to phase in the flat rate over a 5-year period, along with the previously approved phase-in of the increased customer charge of $18.70 per month.

In making the above determination, the Panel considers the evidence regarding a switch to a flat rate – in particular, in the following areas:

- **Cost causation** – the Panel finds the flat rate more closely aligns with cost causation principles than the RCR.

- **Alternative rate designs** – The Panel is satisfied with the alternative designs that have been considered by FBC, and with the level of analysis of each alternative. There is no persuasive evidence that any of these options better meet the objectives that FBC has laid out – i.e. cost causation, customer ease of understanding, additional conservation, or reduced bill impact on high consuming customers – nor are they better aligned with the Provincial government's objectives.
- **Long Run Marginal Cost (LRMC) and its relation to both the Tier 2 rate and the flat rate** – The Panel acknowledges that economic theory is used to support the use of LRMC as a referent for rates that lead to economically efficient consumption decisions on the part of customers and that the BCUC has previously commented that the "appropriate referent for the Tier 2 rate is the LRMC".[1] However, as FBC has pointed out, the LRMC has never actually been used to set its Tier 2 rate.[2] The appropriate LRMC likely lies in the range between something greater than $95/MWh and something less than $131.13/MWh. Given our approval of FBC's proposed flat rate, there is no need to determine a more accurate measure of LRMC at this time.
- **BC's energy policy objectives and the Minister's letter to FBC** – The Panel finds FBC's proposed rate changes are not in conflict with BC's energy policy objectives. We note that efficient electrification remains a key element of the Provincial government's climate action plan. In the Panel's view, the flat rate can contribute to efficient electrification.
- **Bill impacts and the phase-in period** – The Panel finds that FBC's proposed phase-in period of five years appropriately smooths the rate impact related to the move to the flat rate and increased Customer Charge for those customers that are most impacted.
- **Access to natural gas for heat and hot water** – The Panel finds FBC's proposal to replace the RCR with a flat rate and an increased customer charge to be just, reasonable and not unduly discriminatory and it will reduce the significant bill impact that some customers have faced.

Optional Time of Use Rates

The Panel rejects FBC's proposals to revise and re-open the optional residential TOU rate to all residential customers and revise all other non-residential TOU rates.

The Panel acknowledges that FBC, with assistance from its consultant EES, has expended much effort in examining the current TOU rate program and in making changes which it believes will result in a more effective TOU rate program that is more reflective of the current load profile and related costs. However, the Panel has a number of concerns which, when considered collectively lead us to our determination to reject FBC's proposals. These concerns, and the Panel's recommendations for addressing them, are as follows:

- **Lack of examination and analysis related to customer reaction to current TOU rates.** The Panel recommends that prior to moving forward with any future application for TOU rates, that FBC conduct primary research among its existing customer groups to better understand their perspective on the current program and issues they believe need to be addressed.

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[1] FortisBC Inc. (FBC) Application for a Residential Inclining Block Rate, Order G-3-12 and Decision dated January 13, 2012 (RIB Rate Decision), p. 40.
[2] FBC Final Argument, p. 22.

- **Lack of direct customer involvement in developing new TOU rates.** In addition to the lack of research on existing customers, FBC has conducted no research to understand the concerns and expectations of potential new customers to TOU rates. This could provide insight as to how to best design certain elements of the program and how best to communicate with these new potential customers.
- **Lack of financial estimates regarding the financial impact of the TOU rate changes.** An important element of introducing any rate change is to have an indication of how these rate changes will affect customers who participate and those who do not. FBC might consider a series of model impacts ranging from the most likely to less likely outcomes and impacts, and provide explanations as to how these estimates were arrived at.
- **Scope of the TOU program.** The Panel is not persuaded that a full rollout of TOU rates for a three-year program is the most appropriate approach. If conducted carefully, the desired learning with respect to these rates could just as easily be achieved with a pilot program involving a select number of ratepayers in select areas.
- **Lack of specifics related to FBC's goals.** FBC has stated that the goal of TOU rates is to reduce overall peak demand (not shift loads) which in turn will result in less need for outside power requirements and, at some point, potentially lower requirements for additional generation. FBC has provided no evidence that there will be a need for additional generation, so the Panel concludes that expected savings to achieve the goals and objectives will come exclusively from a reduction in outside power requirements. Prior to the implementation of any trial or pilot TOU program, the magnitude of these reductions in outside power requirements must be specified and how this is to be achieved articulated. This will serve as a basis for analysis following the conclusion of the program's initial trial period.
- **Optional TOU program versus other alternatives.** The Panel notes that in its final argument the British Columbia Sustainable Energy Association and Sierra Club of BC (BCSEA-SCBC) observes that FBC's sole focus on TOU rates has potentially precluded examination of other approaches to load shifting and demand response that could be successful. These include options like critical peak pricing and direct (smart) load control which have been chosen by other utilities over optional TOU rates. The Panel notes that these may be worth exploring in the event further analysis dictates that optional TOU rates have little likelihood of success and mandatory TOU rates are likely to result in inequitable treatment of customers.

Commercial Service, Irrigation and Wholesale Rates

In consideration of the Panel's previous approvals regarding changes to the fixed customer and demand charges, the Panel approves FBC's requested revenue neutral changes to the energy charges for RS 20, RS 31, RS 40 and RS 60.

With regard to RS 21, the Panel finds FBC's proposal to flatten the energy rate from a two-tier declining block rate to be reasonable. We agree that declining block rates run counter to conservation objectives and therefore consider a flat rate to be better aligned with Bonbright Principle 3 – Price signals that encourage efficient use and discourage inefficient use. The Panel therefore approves flattening the energy rate to replace the current declining block rate structure, resulting in an energy rate of $0.06875 per kWh for all consumption. The Panel directs that the energy rate be phased-in, in accordance with the Panel's decision regarding the RS 21 Customer and Demand charges.

The Panel approves FBC's proposed changes to the RS 21 and RS 30 transformation discounts, as the changes are cost-based and are driven by the results of the 2017 COSA Study.

The Panel also approves the addition of a transformation discount for RS 40 customers that take delivery at Transmission voltage.

Transmission Services

The Panel approves the Proposed Changes to the tariff for RS 101 and RS 102 as applied for by FBC. However, the Panel finds that the Proposed Changes constitute rate shock for at least one current customer of RS 101, and finds that it is appropriate to mitigate the effects of this shock. We therefore direct that FBC phase-in the rate impact of the Proposed Changes over three years and apply the phase-in period for all applicable customers taking service under RS 101.

Additionally, the Panel recommends that the BCUC establish a proceeding to conduct a broader review of transmission rate harmonization, with the involvement of transmission owners and transmission customers in the Province.

With regard to FBC's transmission and ancillary services, the Panel approves the changes as applied for.

Electric Tariff and General Terms and Conditions

The Panel approves all of FBC's requested changes to its General Terms and Conditions, as shown in Appendix G and H to the Application. The Panel also approves the removal of Schedules 74, 80, 81 and 82 within FBC's Rate Schedules from the Electric Tariff, as the charges contained in these schedules have been moved to the GT&C's section of the Tariff.

The Panel notes that as part of FBC's 2016 Long Term Electric Resource Plan (LTERP) and DSM Plan application, FBC requested that Schedule 90 be rescinded. The Panel approves this request.

The Panel also approves FBC's request to increase the per-read fee for the Radio-Off AMI option from $18 to $19.50 and to continue to record any additional shortfall in the Radio-Off Shortfall Deferral Account until December 31, 2019. The Panel acknowledges that the increase in the per-read fee reflects the increased cost to manually read the meters. FBC is also approved to amortize the balance in the Radio-Off Shortfall Deferral Account over a five-year period from 2019 to 2023. This deferral account shall be closed at the conclusion of the five year amortization period.

The Panel makes the following determinations regarding intervener requests related to FBC's Electric Tariff and General Terms and Conditions:

- The Panel denies the British Columbia Old Age Pensioners' Organization *et al.*'s (BCOAPO) request to direct FBC to separate the charges for new accounts and account transfers. The Panel finds that maintaining the single charge is reasonable, as FBC has stated it does not separately track when the Account Setup or Transfer fee is applied for a new customer requesting an account versus an existing customer requesting to transfer an account.

- The Panel denies ICG's request that the Electric Tariff terms and conditions be revised to include provisions specifying a 30 minute demand window for metering demand. We note FBC's statement that the current metering interval used for billing is consistent with the interval used for FBC's other commercial customers. Given that the intervals are consistent amongst customers, the Panel finds the current approach to be reasonable.

As a result of the Panel's determinations in this Decision, a number of adjustments are required to be made to customer classes' rates. Some of these changes, including rate rebalancing, transitioning to the flat rate from the RCR, increases to certain customer classes' customer charge, and wording changes to the RS 101 tariff, require phase-in periods which must be presented in detail in the compliance filing to this Decision.

FBC is directed to submit to the BCUC, for review by this Panel, a compliance filing containing all of the items directed in this Decision and a proposed implementation date(s) for the changes approved by this Decision. FBC must submit the compliance filing within 60 days of the date of this Decision. The Panel directs that the rate changes identified in this Decision in the various rate schedules be based on the FBC rates in effect in 2017 and be exclusive of any subsequent revenue requirement rate changes that have been approved or may be approved prior to implementation of the changes in this Decision.

1.0 Application and Approvals Sought

1.1 Introduction

FortisBC Inc. (FBC) filed its 2017 Cost of Service Analysis (COSA) and Rate Design Application (RDA) on December 22, 2017 (Application). In its Application, FBC reviews its existing rate design and proposes what it describes as a limited number of changes to rates which it states are in keeping with rate design principles and are brought forward in response to changes in needs and circumstances of certain rate classes. FBC states that the Application is a result of a comprehensive review of its rates and rate related policies as well as a COSA study (2017 COSA Study). EES Consulting Inc. (EES) was retained as a third party expert in public utility rate design matters to develop the 2017 COSA Study as well as to provide assistance in FBC's rate design. The 2017 COSA Study and rate design review considered each of the rate schedules associated with Residential, Commercial, Irrigation and Wholesale customers as well as optional rate structures, transmission access and wheeling rates, and FBC's General Terms and Conditions (GT&Cs).

1.2 Background

FBC states that, including its predecessors, rate design applications have previously been filed with the British Columbia Utilities Commission (BCUC) in 1993, 1997 and 2009. The outcomes of these proceedings are reflected in utility rates as they exist today. In addition, the most recent of these, the Application by FBC for Approval of a 2009 Rate Design and Cost of Service Analysis (2009 COSA and RDA) proceeding, led to further filings of individual rate applications, the results of which are now also embedded in the current rates. These additional filings are inclusive of the following:

- The 2011 Residential Inclining Block (RIB) Rate Application;
- The 2013 Application for Stepped and Stand-by Rates for Transmission Voltage Customers (4 Stages);
- The 2015 Application Regarding FBC's Self-Generation Policy; and
- The 2016 Net Metering Program Tariff Update Application.

The key rate design methodologies approved in the 2009 COSA and RDA and these additional proceedings have been summarized in Table 1.

Table 1: FBC Rate Design – Major Proceedings and Approvals Since 2009[1]

Application	Key Rate Design Methodologies Approved
2009 COSA and RDA Proceeding	• The range of reasonableness for FBC's revenue to cost ratio (R/C ratio) was approved at 95 percent to 105 percent, and if the ratio is outside this range, the appropriate target for rebalancing the R/C ratio was set at unity, subject to defined bill impact constraints with future rebalancing only required when a customer class falls outside the range of reasonableness • For Large Commercial Service – Transmission (RS 31), and Wholesale rates (with exception of TOU rates), the demand component was separated into a power supply charge and a wires charge. • The demand ratchet[20] used to calculate billing demand under the wires charges for both RS 31 and Wholesale customers should be consistent and was set at 80 percent. • The energy rate for small commercial service (RS 20) to be flattened from the two step declining block rate structure • For commercial service (RS 21), the energy rate to move from a three-step to two-step declining block rate in which the first block rate and the flat rate of RS 20 are the same. • Zellstoff Celgar Limited Partnership (Celgar) was transferred from Large Commercial Service – Transmission Time-of Use (RS 33) to (RS 31).
2011 Residential Inclining Block Rate Design Proceeding	• FBC's proposed rate structure consisting of a customer charge, a threshold, and two energy rates was approved. • The threshold at which consumption would be billed at the higher Tier 2 rate was set at 1600 KWh per two-month billing period • A "Pricing Principle" whereby the customer charge would remain unchanged and future revenue requirement increases would be recovered from Tier 2 revenue was put in place for three years. • After the three year period, revenue requirement increases have been applied to all rate components equally (in percentage terms).
2013 Stepped and Stand-by Rates for Transmission (Voltage) Customers Proceeding stage I to IV	• Stage I decision: Several components of proposed stand-by service rate schedule (RS 37) such as notification fee and replacement power energy charge were approved. • Stage II decision: The restrictions for back-up and maintenance services under stand-by service were determined. Three key components of RS 37 were determined: RS 31 contract demand, Standby demand limit (SBDL) and standby billing determinant (SBBD). • Stage III decision: The final form of RS 37 and penalties for exceeding the contractual obligations were approved. The panel set Celgar's contract demand at 3 MVA and its SBDL at 42MVA. • Stage IV decision: Celgar's SBBD was set at 16.8 MVA or at 40 percent of its SBDL.
2015 Self-Generation Policy Proceeding (Stage I)	• The Commission provided guidance to FBC for its Stage II filing regarding a comprehensive self-generation policy as well as generation baseline guidelines.
2016 Net Metering Program Tariff Update Proceeding	• New customers will not be accepted into the Net Metering Program if their proposed generating capacity exceeds their anticipated annual consumption. In addition, FBC's proposal for billing calculation method was approved.

[1] Exhibit B-1, pp. 21–22.

The current Application has been filed with the BCUC pursuant to sections 58-61 of the *Utilities Commission Act* (UCA). FBC states that the Application encompasses a review of its rate design for all rate schedules and includes proposals for a limited number of rate design changes that will adjust rates where indicated by the 2017 COSA Study.

FBC reports that it conducted extensive stakeholder consultation inclusive of information sessions, a technical COSA workshop, notification mail outs, and various meetings with intervener groups. In its view, this engagement process has led to an increased level of stakeholder understanding of the COSA and rate-design related issues.

In preparing the Application, FBC states it has conducted an overall review of its rate design. The 2017 COSA Study was conducted consistent with standard utility practice allowing FBC to assess the adequacy of each rate schedule to recover its allocated cost of service. In addition, FBC's rate schedule review considered rate design principles, government policy, stakeholder comments, jurisdictional comparisons as well as an analysis of load characteristics. Finally, FBC's rate design review was conducted with consideration of customer segmentation, alternative rate structures, the level of fixed versus variable charges, intra and inter-class rate economics and the calculation of demand charges as well as some of the terms and conditions of service.

FBC states that the current rate design is "working as designed" but has proposed a number of changes to improve the consistent application of rate design principles among customer classes. In addition, these changes will respond to the changing needs and circumstances of certain rate classes. Its proposed changes include a limited rate rebalancing, the adjustment of customer and demand charges allowing fixed cost recovery to be more consistent across the customer base.

1.3 Approvals Sought

The Application seeks approval of rate changes with respect to residential rate schedules, commercial and irrigation rate schedules, wholesale rate schedules, optional time of use rates, transmission service rates as well as housekeeping and other amendments to general terms and conditions. Specific details of approvals sought are included in Appendix B, attached to this Decision.

1.4 Regulatory Process

By Order G-23-18 issued on January 25, 2018, the BCUC established an initial regulatory timetable inclusive of a procedural conference which was held in Kelowna, BC on Tuesday March 6, 2018 followed shortly after by a round of Information Requests (IRs) on the Application. Following the procedural conference, by Order G-62-18, a revised regulatory timetable was established providing for a second round of IRs, the filing of Intervener Evidence and Rebuttal Evidence if required and a round of IRs for each. Dates for these were further revised by Order G-101-18 on May 30, 2018. Following submissions from participants on the content and timing for the remainder of the process, the BCUC found that the evidentiary record for the proceeding was sufficient and by Order G-180-18 on September 25, 2018 established the regulatory timetable for written arguments. These were completed on November 22, 2018.

Thirteen parties intervened in the review of the Application:

- British Columbia Hydro and Power Authority (BC Hydro);
- BC Sustainable Energy Association and Sierra Club BC (BCSEA-SCBC);
- Anarchist Mountain Community Society and Regional District of Okanagan-Similkameen (AMCS/RDOS);
- Kaslo Senior Citizens Association, Branch 81 (KSCA);
- Village of Kaslo;
- British Columbia Municipal Electrical Utilities (BCMEU);
- Norman Gabana;
- Irrigation Ratepayers Group (IRG);
- Resolution Electric Limited (Resolution);
- Commercial Energy Consumers Association of BC (the CEC);
- Zellstoff Celgar (Celgar);
- Industrial Consumers Group (ICG); and
- British Columbia Old Age Pensioners Organization *et al.* (BCOAPO).

Most of the interveners participated fully in the regulatory process, although a few were selective as to their level of participation.

1.5 Approach to Review of the Application

Section 2.0 of this Decision is designed to provide context and includes a review of topics of importance to this Application, including the Bonbright Principles, the *Clean Energy Act* (CEA), residential and inclining block rate history, and BC Government direction. Section 3.0 reviews the 2017 COSA Study with a discussion of COSA-related issues. In addition, this section addresses changes in rate rebalancing and issues related to the range of reasonableness. Section 4.0 is focused on changes to rate design as proposed by FBC. This section begins with a review of changes to fixed cost recovery before considering changes to residential rates which deals with two major issues: the Residential Conservation Rate (RCR) versus the proposed flat rate; and FBC's proposal for optional Time of Use (TOU) rates. Section 4.0 also considers changes to Commercial Service, Irrigation and Wholesale Rates before considering issues related to Transmission Services, with a detailed discussion of issues related to rate harmonization for Rate Schedules (RS) 101 and RS 102. Finally, Section 5.0 deals with issues related to Electric Tariff and General Terms and Conditions.

2.0 Context to Rate Design and Cost of Service Analysis

As context to its Application, FBC provided information on a number of internal and environmental factors that it believes are relevant and have been considered in preparing this Application. Among these are the following:

- Rate design principles;
- The CEA;
- The history related to RIB rates and FBC's RCR; and
- BC Government direction.

The Panel agrees that these are important considerations and provides a brief review of each one to provide context that is relied upon within this Decision.

2.1 Bonbright Principles

FBC states that the fundamental principles relied upon in this Application are those identified by Dr. Bonbright in his book “Principles of Public Utility Rates.” Specifically, FBC has relied upon principles as summarized by the BCUC in the BC Hydro RIB Rate Re-Pricing Application Decision.[2] These are listed as follows:

Principle 1: Recovering the Cost of Service; the aggregate of all customer rates and revenues must be sufficient to recover the utility’s total cost of service.

Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates).

Principle 3: Price signals that encourage efficient use and discourage inefficient use.

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.

Principle 8: Avoidance of undue discrimination (inter-class and intra-class equity must be maintained, and if possible, enhanced.[3]

FBC describes rate design as a balancing process requiring the consideration of viewpoints from various stakeholders and the application of multiple and what are sometimes conflicting principles. Further, different rate design principles may have varying levels of importance dependent upon the context. FBC states that it has therefore applied its judgment and experience in balancing the most relevant principles in a given context when identifying rate design issues and proposing solutions. While considering the principle of cost causation as a foundation for cost allocation and rate design, FBC does not apply any particular weighting or priority to the eight principles.[4]

2.2 *Clean Energy Act*

The CEA, announced by the BC Government on April 28, 2010, advanced sixteen specific energy objectives. These objectives addressed electricity self-sufficiency, using clean and renewable energy sources, demand-side management (DSM) and energy conservation, greenhouse gas (GHG) emission reduction targets, and encouraging fuel switching to lower carbon intensity energy sources all of which do not apply to FBC (Appendix B includes a complete listing of the sixteen BC Government energy objectives). FBC states that the applicable objectives were embodied in the BCUC’s decision on FBC’s 2009 COSA and RDA (2009 RDA Decision) as well as the rate design proceedings established as a result of the 2009 RDA Decision.[5]

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[2] BC Hydro RIB Rate Re-Pricing Application, Order G-45-11 and Reasons for Decision dated March 14, 2011, p. 5.

[3] Exhibit B-1, p. 16.

[4] Ibid., pp. 16-17.

[5] Ibid., p. 17.

2.3 BC Hydro RIB Rate and FBC RCR History

In response to complaints to the Minister raised by customers of BC Hydro and FBC, the BCUC was requested to report to government on the impact of BC Hydro's RIB rate and FBC's RCR on customers (in particular, those who do not have access to natural gas for home heating and those who are low-income customers). FBC states that in response to this request a consultation process was initiated by the BCUC with utilities and the public where utilities were asked to respond in the form of a report to a series of questions raised by the Minister. The resultant BCUC RIB Rate Report was released on March 28, 2017.

FBC reports that the BCUC RIB Rate Report states there is a kilowatt-hour (kWh) per billing period break-even point above which the RCR bill exceeds the equivalent flat-rate bill and below which the RCR bill is lower. With reference to this, the BCUC RIB Rate Report concluded that this is neither unjust, unreasonable, unduly discriminatory nor unduly preferential and does not constitute a subsidy. FBC states that in response to the BCUC RIB Rate Report, the Minister sent a letter to BC Hydro and FBC on April 10, 2017, which referred to FBC's then upcoming rate design application and asked FBC to use this opportunity to "examine a range of alternative rate designs with price signals for energy efficiency and electrification". The Minister's letter concludes with the following:

> 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.[6]

FBC states that in alignment with this letter, it has considered customer bill impacts for varying circumstances along with traditional rate design principles.[7]

2.4 BC Government Direction

FBC references the 2016 BC Climate Leadership Plan (CLP) released in August of 2016, which discusses advancement of efficient electrification through work with BC Hydro on the expansion of DSM programs that include investments that increase efficiency and reduce GHG emissions. FBC notes that the CLP also supports the expansion of the Clean Energy Vehicle Program and stated the government's commitment to 100 percent renewable or clean energy generation except where there is a need to address reliability and cost concerns. FBC notes that its investments in vehicle charging stations and its forthcoming EV Charging Applications demonstrate its commitment to the CLP policies.

FBC points out that the BC government has been consistent in its support of postage stamp rates, noting that the BCUC has consistently rendered decisions supporting their application. However, FBC also asserts that postage stamp rate setting "does not necessitate that rates must or should be the same across the service territories of different utilities across the province." FBC cites the Application by FBC for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan Decision,[8] in which the BCUC stated there

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[6] Exhibit B-1, p. 18; Appendix J.

[7] Ibid., pp. 18–19.

[8] Application by FBC for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan, Order G-110-12

was no mandate nor did "it find it appropriate, to require FortisBC to manage its utility business to produce rates or programs identical to those of BC Hydro."[9]

3.0 2017 COSA Study and Rate Rebalancing

The following sections provide an overview of the 2017 COSA Study and the implications and results on FBC's various customer classes, including the revenue to cost (R/C) ratios resulting from the 2017 COSA Study and FBC's proposal for rate rebalancing. A number of issues were raised by interveners related to the COSA, including FBC's use of the minimum system study approach, the use of the 2 coincident peak (2 CP) for allocation, the treatment of RS 37 revenues, and the functionalization and classification of certain items within the 2017 COSA Study. These issues are addressed in Section 3.2 of the Decision. FBC's proposal for rate rebalancing and the Panel's determinations are provided in Section 3.3.

3.1 Introduction and Overview of the 2017 COSA Study

FBC's 2017 COSA Study, performed by EES, provides the basis for the rate design recommendations in the Application. FBC last filed a COSA study in 2009 (2009 COSA Study) as part of the 2009 COSA and RDA. EES also conducted the 2009 COSA Study and has been utilized by FBC to perform COSA and RDA work since 1982.[10]

The basic purpose of a COSA study, as explained by FBC, is to "equitably allocate the costs of operating the utility (as represented by the Revenue Requirement) to the various customer classes of service in order to determine the level of revenue responsibility for each class." The equitable allocation of costs is one of Bonbright's eight rate design principles. This principle is described as the "fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates)."[11]

FBC states that the methodology from the 2009 COSA Study and the resulting BCUC decisions[12] were considered as a starting point for the 2017 COSA Study. The inputs and assumptions included in the 2017 COSA Study are as follows:

- The total approved 2017 revenue requirement of $360.7 million, which includes an offset of $9.5 million in revenues from sources other than electric rates.
- A 2017 mid-year rate base of $1.28 billion, which includes the mid-year gross plant of $1.9 billion, offset by accumulated depreciation and customer contributions.
- Average total customers for 2017 of 133,853 and gross energy consumption of 3.3 million mega-watt hours (MWh).
- A forecast winter system peak of 761 megawatts (MW) and a forecast summer peak of 634 MW.
- Classification of monthly power supply costs as demand-related or energy-related based on the demand and energy charges for electricity supply from BC Hydro under RS 3808, allocated on a monthly basis.

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dated August 15, 2012 and decision, p. 20.
[9] Exhibit B-1, pp. 19-21.
[10] Ibid., p. 41.
[11] Ibid., p. 16.
[12] Orders G-156-10, G-196-10, G-24-11, G-57-11.

- Classification of distribution plant based on a "minimum system" approach. A peak load carrying capability (PLCC) credit was applied to correct for the inherent double counting of demand with the standard minimum system study.
- Allocation of demand-related transmission costs using the 2 CP method, which is the sum of two winter and two summer peaks.[13]

FBC states that customers are grouped into classes that reflect common usage characteristics or facility requirements. The following are the main customer classes:

- Residential;
- Small Commercial;
- Commercial;
- Large Commercial Primary;
- Large Commercial Transmission;
- Lighting;
- Irrigation;
- Wholesale Primary; and
- Wholesale Transmission.[14]

FBC provided the following table which shows the number of customers in each customer class and the amount of energy sales in gigawatt hours (GWh):[15]

Table 2: Number of Customers and Energy Sales by Customer Class

Customer Class	Rate Classes	Number of Customers (%)	Energy Sales GWh (%)
Residential	RS 01, RS 02, RS 03	115,595 (86%)	1,353 (41%)
Commercial	RS 20, RS 21, RS 22, RS 23	15,517 (12%)	879 (27%)
Industrial (Large Commercial)	RS 30, RS 31, RS 32, RS 33	50 (0.04%)	407 (12%)
Wholesale	RS 40, RS 41, RS 42, RS 43	6 (0.004%)	587 (18%)
Lighting & Irrigation	RS 50, RS 60	2,685 (2%)	55 (2%)
Total		133,853 (100%)	3,282 (100%)

The key steps to developing a COSA study are the functionalization, classification and allocation of costs.

Functionalization separates costs into major categories that reflect the utility's plant investment and different services provided to customers. The primary functional categories are production (power supply), transmission, distribution and general. Once functionalized, the costs are classified to cost-causation categories. The cost-

[13] Exhibit B-1, pp. 41-42.
[14] Ibid., p. 42.
[15] Exhibit B-8, BCUC IR 14.1.

causation categories are demand, energy and customer. Demand-related costs are fixed costs that vary with the kilowatt (kW) demand imposed on the system. Energy-related costs are variable costs that vary with the kilowatt-hours (kWh) provided by the utility. Customer-related costs are those that vary with the number and type of customers served. The classified costs are then allocated to specific customer classes based on the customer's contribution to the specific classifier selected.[16]

3.2 2017 COSA Study Issues

The following sections address the 2017 COSA Study-related issues raised by interveners and provide the Panel's discussion and determinations on these issues, as well as the Panel's determination on the 2017 COSA Study as a whole.

3.2.1 Use of the Minimum System Study

FBC classifies distribution costs using the Minimum System Study (MSS) approach and by applying a PLCC credit to correct for the inherent double counting of demand with the standard MSS.

Distribution services include all services required to deliver the energy supply from the point of interconnection between the transmission system and the utility's load centres to the end use of the power. Most distribution costs are split between demand and customer components. The demand component is the cost of facilities built to serve a particular load, such as distribution substations. The customer component is the cost of facilities that varies with the number of customers, such as meters.[17]

What is the MSS?

The MSS is a theoretical analysis using both engineering and accounting inputs to develop a split of the distribution costs between demand and customer components. The MSS analysis is used to theoretically determine the lowest level of plant investment required to serve a utility's customers compared to the actual facilities in place to meet varying customer demands. EES describes the approach as reflecting "the philosophy that the system is in place in part because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kWh of energy per year." The MSS method assumes that a minimum-size distribution system can be built to serve the minimum loading requirements of the customer. The total costs of the minimum-sized system are then compared to the cost of the as-built system to reflect the percentage of costs attributed to the system that would be in place if all customers used a minimum amount of power. The remaining percentage of costs is then attributed to the demand-related component.[18]

What is the PLCC adjustment?

The PLCC adjustment determines how much demand for a customer class can be met by the minimum system and credits this amount against the classification's non-coincident peak (NCP) demands used for determining demand allocators. The adjusted customer class's NCPs can then be used to allocate the distribution demand-related costs, eliminating double-counting. The issue of over-allocating demand arises because the minimum

[16] Exhibit B-1, p. 45; Appendix A, p. 7.
[17] Ibid., Appendix A, p. 25.
[18] Ibid., Appendix A, pp. 25–26.

system, while in theory designed to carry only a minimal amount of load, is actually capable of carrying some amount of demand. This results in an overstatement of the customer-related component.[19]

The following table shows the percentage splits between demand-related and customer-related costs based on the MSS and PLCC adjustment:[20]

Table 3: Classification of Distribution Costs using MSS and PLCC Adjustment

Description	Classified to:		Note:
Distribution	Substations	100% Demand	Per Minimum System Study with Peak Load Carrying Capability (PLCC) Adjustment
	Poles, Towers & Fixtures	19% Demand 81% Customer	
	Conductors & Devices	35% Demand 65% Customer	
	Line Transformers	31% Demand 69% Customer	
	Services, Meters and related	100% Customer	
	Street Lights and Signals	Direct Assignment[40]	

[40] These costs are all directly related to the lighting class of customers and are directly assigned to that class.

Other Classification Methods and Jurisdictional Comparisons

In the 2017 COSA Study, EES states that there are generally two methods that can be used to classify distribution costs: the 100 percent demand method and the MSS approach. The 100 percent demand methodology assumes the distribution system is built to meet the NCP; thus, distribution costs are classified as 100 percent demand-related. Another method which can be used to classify distribution costs is the zero-intercept method. This method is very similar to the MSS approach, except that it creates a theoretical size of equipment which would carry zero load on the system.[21]

EES provided the following table summarizing the classification splits for each of the jurisdictions analyzed by EES:[22]

[19] Exhibit B-1, Appendix A, p. 27.
[20] Ibid., Table 5-7, p. 49.
[21] Ibid., Appendix A, pp. 24, 26.
[22] Exhibit B-21, BCUC IR 116.1.

Table 4: Jurisdictional Comparison of Distribution Cost Classification

	BC Hydro	ATCO Electric Alberta	Fortis Alberta	Manitoba Hydro
Substations	100% Demand	100% Demand	Skips step where costs are split between demand and customer and allocates directly by class	100% Demand
Poles, Towers & Fixtures	50% Demand 50% Customer	30% Demand 70% Customer		60% Demand 40% Customer
Conductors & Devices	50% Demand 50% Customer	30% Demand 70% Customer		60% Demand 40% Customer
Line Transformers	50% Demand 50% Customer	40% Demand 60% Customer		100% Demand
Services, Meters	100% Customer	100% Customer	100% Customer	100% Customer
Street Lights & Signals	Direct Assignment	NA	NA	NA
	Hydro Quebec	Nova Scotia Power	Newfoundland Power	New Brunswick Power
Substations	100% Demand	NA	100% Demand	100% Demand
Poles, Towers & Fixtures	79% Demand 21% Customer	65% Demand 35% Customer	64% Demand 36% Customer	50% Demand 50% Customer
Conductors & Devices	79% Demand 21% Customer	60% Demand 40% Customer	64% Demand 36% Customer	50% Demand 50% Customer
Line Transformers	100% Customer	NA	73% Demand 27% Customer	75% Demand 25% Customer
Services, Meters	100% Customer	NA	100% Customer	100% Customer
Street Lights & Signals	NA	NA	NA	Direct Assignment

EES confirmed in response to BCUC IR 26.1 that only two out of the eight utilities surveyed (Hydro Quebec and Newfoundland Power) use a minimum system approach. When asked to describe the methods used by the other six utilities, EES responded as follows:

> It does not appear that any of the six utilities used a zero-intercept method in developing the splits. In most cases there is not analysis presented in the rate filings to support the splits and in many cases they have been used for many years. The percent splits are often round numbers, like 70 percent/30 percent or 50 percent/50 percent, leading us to believe they were not based on a pure analytical approach.[23]

EES provided the following assessment of the various methods:

- **100 percent demand approach** – advantageous for residential and other small customers and is a simpler approach with fewer data requirements. It does not reflect the fact that one large customer would likely require far fewer distribution facilities than a combined group of 100 customers with the same peak load.

[23] Exhibit B-8, BCUC IR 26.1, 26.2.

- **Zero intercept method** – best matches the theory behind a minimum system; however, the results do not make sense as the zero-intercept cost is often a negative number or the regression used does not have a high level of statistical significance.
- **Fixed or negotiated split between customer and demand components** – may balance the interests of various stakeholders and reflect some recognition that both customers and peak demand are factors in the need for distribution facilities. However, it is not data intensive and is highly uncertain.
- **MSS approach** – matches the theory that both the customers and the peak load of those customers contribute to the need for distribution facilities. It allocates a greater cost on residential and other small customers than the 100 percent demand approach. It is data intensive but subject to uncertainty.[24]

In addition to these alternatives, EES states it has increasingly seen the use of more detailed studies that look at the actual use of the distribution system by various customer classes, rather than completing the classification and allocation steps required by an MSS. Such an approach requires more detailed data than the MSS approach and provides a greater level of complexity. Additionally, the analysis is usually completed for a sample of the system rather than for the entire system. EES submits that in its experience, any shift away from the MSS is towards more complex methods rather than to a more simple approach such as the 100 percent demand approach. The reason for this shift is that there is greater data availability arising from new technologies.[25]

Positions of the Parties

With the exception of KSCA, the interveners either support or express no opinion on the use of the MSS approach and PLCC adjustment.

The CEC submits that the MSS approach with the PLCC adjustment should be used because the information is readily available and it is presently the better method available, when compared to the 100 percent demand approach. The CEC does not consider the 100 percent demand approach suitable because it "moves away from the information for cost causation to a simplistic assumption." The CEC suggests, however, that moving towards methodologies that utilize increased detail, such as those discussed in response to BCUC IR 118.2, could be useful in future COSA studies.[26]

BCOAPO considers the MSS method when combined with the PLCC adjustment to be a reasonable approach to splitting distribution system costs between demand and customer. In BCOAPO's view, this approach is reasonable because "facilities must not only be sized to meet the total load being delivered but must also be built so as to deliver that power to all customers (i.e. the amount of poles and lines and number of transformers required will vary with the number of customers on the system)."[27]

KSCA opposes the use of the MSS and PLCC adjustment for classifying distribution costs, stating that it does not address the "complexity in the range in size of residential property that now exists, and the broad range of residential appliance and equipment uses that also now exist."[28] Instead, KSCA requests that the BCUC direct

[24] Exhibit B-8, BCUC IR 26.2.1.
[25] Exhibit B-21, BCUC IR 118.2.
[26] CEC Final Argument, pp. 6–7.
[27] BCOAPO Final Argument, p. 20.
[28] KSCA Final Argument, p. 15.

FBC to set the "residential Basic Customer Charge (BCC) at a rate of no more than 100% of those delineated costs as espoused by the rate design-making principles of Garfield and Lovejoy…, as supported by the statement of James Bonbright…, and in accordance with, for example, the applied practices of the Washington Utilities and Transportation Commission (WUTC)."[29]

With regard to the fact that FBC has been approved by the BCUC to use the MSS approach in previous RDA decisions, KSCA argues that what the BCUC "allows or directs a utility to do in one era is not necessarily the right approach in another, and just because other utilities use the MSS methodology does not mean that it is the right one to use in the FBC service area in 2018." KSCA asserts that customer-related costs should be "strictly limit[ed]" to the following:

- The amortized capital cost of a smart meter;
- The cost of reading a meter;
- Computing the information and billing the customer; and
- Any additional capital, fixed and variable costs associated with servicing a customer's account.[30]

KSCA further asserts that any distribution-related costs "in the form of 'poles, conductors and transformers' should be stripped away from the true customer related costs, as they are in fact capacity or demand related costs that more properly belong in the energy portion of a residential customers bill."[31]

KSCA requests the BCUC to consider whether "allowing FBC to continue using both the MSS methodology and its variant PLCC creates an unduly discriminatory BCC [basic customer charge] rate, and as a question of fact, this form of COSA analysis should be discontinued in accordance with section 59(4) of the UCA."[32]

FBC responds that the MSS and PLCC adjustment approach is a "valid and accepted standard in multiple jurisdictions and used by NARUC [National Association of Regulatory Utility Commissioners] generally." FBC points to the fact that the MSS has been approved by the BCUC in FBC's previous three COSAs and the MSS was approved for use by the BCUC in FortisBC Energy Inc.'s (FEI) recent RDA.[33]

FBC argues that KSCA "bases much of its justification for a low Customer Charge on a misunderstanding of the manner in which costs are allocated, including through the use of the minimum system study and confusion between capacity and energy related costs." FBC states that it will appropriately assume that most, if not all, residential customers have the same capacity requirement. The capacity requirement is based on a peak demand requirement, not energy use over the year, and installed facilities are likely the same for most customers. FBC further states that its system is designed to ensure that the maximum use of each customer can be met, regardless of whether it occurs one hour per year or in all hours of the year and that FBC must plan for the maximum peak demand for a typical residential customer.[34]

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[29] Ibid., p. 1.
[30] Ibid., p. 12.
[31] Ibid., p. 12.
[32] Ibid., p. 17.
[33] FBC Reply Argument, p. 36.
[34] Ibid., p. 38.

FBC points outs that the major differences in the need for poles, wires and transformers is based on terrain and density, and that those factors have more influence on the number of poles and transformers and the length of wire as opposed to customer size. FBC submits that if the cost of the distribution equipment is primarily recovered in the energy charge instead of a Customer or Demand Charge, customers that use very little energy during the year “will not pay a fair share of the cost.”[35]

Panel Determination

The Panel acknowledges that utilities use a variety of approaches to classify distribution costs. While only a limited number of the utilities reviewed by EES in its jurisdictional analysis appear to use the MSS, there are at least two examples of utilities in other jurisdictions that do. Further, FEI’s use of the MSS was recently affirmed by the BCUC in the FEI 2016 RDA proceeding (and Order G-4-18).

As stated previously, the purpose of the 2017 COSA Study is to equitably allocate the costs of operating the utility to FBC’s various customer classes. The Panel must therefore assess whether the MSS method with the PLCC adjustment reasonably assigns FBC’s distribution costs to the driver of those costs (i.e. demand or customer). The Panel agrees with FBC, the CEC and BCOAPO that the MSS method with the PLCC adjustment reasonably reflects cost causation because most distribution costs, with the exception of substations and services and meters, are driven by a combination of both the size of the load and the number of customers.

KSCA in its final argument has used the term “basic customer charge” or “BCC” to voice its opposition both to FBC’s proposal to increase the percentage of fixed costs recovered through the basic charge and to FBC’s proposal to classify distribution costs using the MSS and PLCC adjustment. While the method of distribution cost classification does impact the amount of costs classified as demand-related compared to customer-related, it does not in and of itself impact the percentage of fixed costs to be recovered from residential customers through the basic charge. Additionally, as FBC stated in its reply argument, shifting of costs from customer-related to demand-related does not necessarily mean the costs will not be allocated to residential customers.[36]

The Panel is satisfied that the MSS, when combined with the PLCC adjustment to avoid double-counting of demand, is a reasonable approach for classifying distribution costs. There is no evidence that this approach does not provide reasonable results based on FBC’s specific circumstances. Further, while the UCA does not require consistency with past BCUC decisions, the Panel finds in this instance that consistency with the method approved by the BCUC in the 2009 RDA Decision is appropriate, particularly as there have been no circumstances identified by FBC or interveners which support a deviation from the current method. The Panel disagrees with KSCA’s argument that the “complexity in the range in size of residential property that now exists, and the broad range of residential appliance and equipment uses that also now exist”[37] support a change from the MSS and PLCC adjustment. As noted by FBC, KSCA appears to have applied the concepts of capacity and energy use incorrectly.[38]

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[35] FBC Reply Argument, p. 38.
[36] Ibid., pp. 36-37.
[37] KSCA Final Argument, p. 15.
[38] FBC Reply Argument, p. 38.

KSCA argues that FBC should be directed to set the residential BCC at a rate of "no more than 100% of those delineated costs as espoused by the rate design-making principles of Garfield and Lovejoy." KSCA references Garfield and Lovejoy when arguing that the BCC should only include the costs related to "meter reading, billing, collecting and accounting, and the costs associated with such company property as metering equipment and service connection."[39]

The Panel does not find this approach reasonable. As stated previously, the Panel finds that most distribution costs, with the exception of substations and services/meters, are driven by a combination of both the size of the load and the number of customers, and are therefore appropriately classified as both demand-related and customer-related costs. The Panel also notes that despite the fact that EES' jurisdictional analysis shows the majority of utilities do not use the MSS and PLCC adjustment method, the majority of utilities also do not restrict the classification of customer-related distribution costs to the narrowly defined cost categories proposed by KSCA. This is evidenced by the fact that most distribution cost categories are split between demand-related and customer-related components to varying degrees.[40] Thus, even if the Panel were to consider an alternative classification approach to the MSS and PLCC adjustment, we would not be persuaded that KSCA's proposed approach is an appropriate alternative, as we do not consider such an approach to reflect cost causation.

Based on the reasons stated above, the Panel declines to take the actions requested by KSCA regarding the classification of distribution costs.

3.2.2 Treatment of RS 37 Revenues

FBC's 2017 COSA Study uses the approved 2017 revenue requirement of $362.1 million. The revenue requirement is then adjusted for RS 37 revenues of $1.4 million, which results in a "COSA" revenue requirement of $360.7 million.[41]

FBC explains that it has a single customer taking service under RS 37 (Stand-By and Maintenance Service). RS 37 is available to customers taking service under RS 31 (Large Commercial Service – Transmission). The RS 37 rates are calculated based on the hourly Mid-C price in effect when stand-by service is used. FBC states that the RS 37 revenues are outside of the typical embedded COSA framework because the actual rate and revenue are market-driven rather than being based on a value per billing unit that has been approved by the BCUC. This also results in the energy sales being made at rates below the fully embedded cost resulting from the 2017 COSA Study.[42]

FBC submits that because the RS 37 rates are less than the fully embedded cost resulting from the 2017 COSA Study, it treats the revenues as an offset to the overall revenue requirements and therefore the revenues are allocated to all ratepayers to compensate for the use of the system, which is paid for by all ratepayers. FBC states the energy and demand associated with the RS 37 sales are also left out of the RS 31 class amounts and

[39] KSCA Final Argument, pp. 1, 6.
[40] Exhibit B-21, BCUC IR 116.1.
[41] Exhibit B-1, p. 43.
[42] Ibid., p. 43.

the total system amounts. FBC considers customers to be better off having the standby sales because "even at a reduced rate, the sales are contributing to the fixed costs of the system."[43]

FBC explained in response to an ICG IR that the revenues associated with RS 37 are related to service from generation and transmission facilities. If the 2017 COSA Study was changed to allocate the revenues only on the basis of generation and transmission rate base, the R/C ratio for the RS 31 class would change from 107.0 percent to 107.2 percent (before FBC's proposed rate rebalancing).[44]

Positions of the Parties

ICG makes two separate arguments regarding RS 37. It characterizes the first argument as "Revenue to Cost Ratios for RS 37" and the second argument as "RS 37 Revenues and R/C ratios." With regard to the first argument, ICG states: "Given the significant time and expense of all interested parties and the Commission to approve RS 37, this Commission Panel should not now review RS 37 service and rates."[45] ICG argues that RS 37 has been the subject of many regulatory decisions, and is a unique service that "should not have been, and, as noted by FBC, was not included in the COSA."[46]

With regard to ICG's second argument, it notes that RS 37 is not included as a rate class in the 2017 COSA Study; however, the revenues from RS 37 are included in the R/C ratios that are calculated in the 2017 COSA Study and are therefore included in the calculation of the R/C ratios for all customer classes. ICG submits that "only RS 31 customers are eligible to take RS 37 service and although RS 31 service is 'firm service' and RS 37 service is 'stand-by service' the use of those services is integrated to provide 'full service'." Additionally, the rates are integrated through the application of demand charges from RS 31 to RS 37. Based on these points, ICG argues that the RS 37 revenues should be included in the revenues for the purpose of the R/C ratio calculations of RS 31 customers only and requests that the BCUC direct FBC to recalculate the R/C ratios in the 2017 COSA Study on this basis.[47]

FBC responds that it has explained its rationale for the 2017 COSA Study treatment of the RS 37 revenues and continues to believe it is appropriate. FBC argues that the revenues are intended to compensate all customers for use of the fixed system and are allocated to all customers that contributed to the fixed costs of the utility required to provide RS 37 service to a customer that is normally self-generating power to meet plant load.[48]

FBC further argues the following:

> The change requested by ICG should not be granted by the BCUC in light of the immaterial impact it would have and the likelihood that RS 37 will be amended to also be available to self-generating customers taking service under RS 30 as an outcome of the Company's Self-Generating Policy Application that is awaiting a BCUC Decision.[49]

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[43] Ibid., p. 43.
[44] Exhibit B-15, ICG IR 4.1.
[45] ICG Final Argument, pp. 16–17.
[46] Ibid., p. 16.
[47] ICG Final Argument, pp. 17–18.
[48] FBC Reply Argument, pp. 72–73.
[49] Ibid., p. 73.

Panel Determination

The Panel accepts FBC's approach of applying the RS 37 revenues as an offset to the overall revenue requirement. We find this approach appropriate because all customers are contributing to the fixed costs of FBC's system which is providing service to RS 37; thus all customers should receive the benefits of the RS 37 revenue. Further, RS 37 rates are calculated based on the hourly Mid-C price in effect when stand-by service is used and are therefore outside of the embedded COSA framework.

The Panel notes that while ICG argues to apply the RS 37 revenues only to the RS 31 customer class, it does not support including RS 37 as a rate class in the 2017 COSA Study. The Panel agrees it is not appropriate in this proceeding to re-examine whether the RS 37 customer class should be included in the COSA as this issue has been the subject of many recent regulatory reviews. The Panel also considers, however, that it is not reasonable at this time to consider changing the treatment of the RS 37 revenues within the 2017 COSA Study, particularly given that the energy sales made to RS 37 customers are at rates below the fully embedded cost resulting from the 2017 COSA Study. **The Panel therefore declines to take the actions requested by ICG regarding RS 37 revenues.**

3.2.3 Other 2017 COSA Study-related Issues

A number of additional 2017 COSA Study-related issues were raised by interveners in final arguments. In the cases where a request or recommendation has been made, the issue is outlined in the following section and the Panel provides a discussion and/or determination where appropriate.

3.2.3.1 Treatment of Generation-Related Transmission Assets

BCOAPO argues that FBC should be directed to functionalize Generation-Related Transmission Assets (GRTA) as generation and, for the purposes of classification and allocation, treat it the same as FBC-owned generation.[50]

BCOAPO states the functionalization of GRTA to generation is consistent with the principle of cost causation and with standard COSA practice. BCOAPO further references FBC's response to BCOAPO's IRs in which FBC stated: "It would be reasonable to separate out the transmission assets that are associated with generation integration, functionalize them as production, and treat them on the basis as power supply classification."[51]

BCOAPO disputes FBC's other justifications for treating GRTA as transmission, i.e. that the treatment is consistent with previous COSA approvals and the R/C ratio impacts are minor. BCOAPO argues "past practice should not be the basis for continuing to use an approach that has been shown to be incorrect" and the fact that the impacts are minor is not an "acceptable reason in [a] situation such as this one where the correct approach can be implemented with minimal effort and cost."[52]

While BCOAPO makes the aforementioned arguments regarding GRTA in the "functionalization" section of its final argument, it does not reference the GRTA issues in its sections on classification of generation and/or transmission. Instead, BCOAPO submits that "FBC's approach to classifying Generation costs is reasonable and

[50] BCOAPO Final Argument, p. 14.
[51] Ibid., p. 13.
[52] Ibid., p. 14.

should be accepted by the BCUC" and "FBC's classification of Transmission costs is consistent with standard industry practice and it recommends that it be approved by the BCUC."[53]

BCOAPO references the GRTA in its section on allocation of transmission costs. BCOAPO states the use of the 2 CP factor is appropriate for transmission costs; however, its "preceding comments regarding the actual determination of the 2 CP factor for demand-related generation costs are equally applicable with respect to the allocation of transmission costs."[54]

FBC responds that it has provided its rationale for the 2017 COSA Study treatment of the GRTA in response to BCOAPO IR 36.3, in which FBC stated the 2017 COSA Study followed the Federal Energy Regulatory Commission (FERC) accounts when functionalizing costs. FBC states: "Generally speaking, it would not object to either approach, however, the difference in terms of the COSA results are minimal and FBC believes that comparability to previous COSAs has value and changes to the current COSA should be avoided if possible."[55]

FBC also notes "there are a variety of decisions that must be made when conducting a COSA, and often there is not a 'correct' answer and some judgement is required and acceptable."[56]

Panel Determination

The Panel has considered both parties' submissions and finds both approaches are reasonable. However, while both parties have presented positions which the Panel finds reasonable, we are not persuaded that one approach is superior to the other. **Because consistency between current and past COSA studies allows for easier comparisons to be made, the Panel declines to direct FBC to make the changes to the 2017 COSA Study requested by BCOAPO.**

3.2.3.2 Functionalization and Classification of DSM Costs

BCOAPO argues that for the purposes of functionalizing DSM costs between transmission and distribution, investments in accounts 369 (Services), 370 (Meters/AMI Meters), 371 (Installation at Customer Premises) and 373 (Street Lights and Signal Systems) should be excluded from the value used for the distribution rate base. BCOAPO's rationale for this exclusion is that DSM spending is unlikely to impact the need for Meters, Services, and Street Lighting facilities.[57] BCOAPO makes a similar argument for the classification of DSM costs.[58] BCOAPO does not reference any IRs where this issue has been explored; however, it did pose an IR to FBC requesting the utility to explain how classifying a portion of DSM costs as distribution-customer is consistent with the planning basis for DSM and the principle of cost causation. FBC responded to this IR as follows:

[53] Ibid., p. 19.
[54] Ibid., p. 23.
[55] FBC Reply Argument, pp. 74–75; Exhibit B-11, BCOAPO IR 36.3.
[56] FBC Reply Argument, p. 74.
[57] BCOAPO Final Argument, p. 15.
[58] Ibid., p. 21.

> When evaluating whether or not a DSM measure is cost-effective, FBC looks at the avoided cost of power supply as well as future T&D [Transmission & Distribution] costs. However, the COSA is not based on future distribution costs but is instead based on embedded costs. The portion of DSM treated as distribution-related is treated on the same basis as all of the embedded distribution costs, which includes a customer-related component.[59]

FBC does not respond to BCOAPO's argument regarding the exclusion of certain accounts when functionalizing and classifying DSM costs.

Panel Determination

The Panel denies BCOAPO's request regarding the functionalization and classification of DSM costs. BCOAPO's argument that certain accounts should be excluded from the value used for the distribution rate base is not supported by evidence. The Panel also agrees with FBC's statement in its reply argument that there are a variety of decisions that must be made when conducting a COSA study and some judgement is required. The Panel considers this to be an instance where FBC reasonably applied its judgement when functionalizing and classifying DSM costs and therefore accepts FBC's approach.

3.2.4 Demand Allocation Alternatives

FBC uses the 2 CP allocator for generation and transmission rate base accounts. The 2 CP allocator is used to represent FBC's dual winter/summer peak.[60]

FBC explained in response to a BCUC IR that when evaluating whether the 2 CP allocator is appropriate it looks at the following factors: the overall shape of the system; how close the summer peaks are to winter peaks; whether the load shape has changed since the last COSA study; the results of the FERC and Ontario Energy Board (OEB) tests; whether any other factors related to planning for system facilities have changed; and whether any precedents in BC or other jurisdictions have changed enough to warrant a change for FBC.[61]

FBC provided the following table which shows the adjusted R/C ratios by class using the 2 CP, 1 CP, 4 CP and 12 CP to allocate production and transmission.[62]

[59] Exhibit B-23, BCOAPO IR 93.1.
[60] Exhibit B-1, Appendix A, p. 32.
[61] Exhibit B-21, BCUC IR 115.1.1.
[62] Exhibit B-8, BCUC IR 30.5.

Table 5: Demand Allocators for Production and Transmission

	2 CP	1CP	4CP	12 CP
Residential	98.4%	97.7%	97.9%	99.6%
Small Commercial 20	102.2%	102.5%	102.6%	101.3%
Commercial 21/22	104.7%	106.5%	104.8%	101.1%
Large Commercial Primary 30/32	104.0%	106.9%	106.3%	100.0%
Large Commercial Transmission 31	107.0%	112.6%	108.9%	105.9%
Lighting	92.2%	90.3%	89.4%	90.9%
Irrigation	97.2%	110.6%	110.4%	96.6%
Wholesale Primary 40	96.7%	96.9%	97.4%	98.0%
Wholesale Transmission 41	103.9%	89.6%	95.2%	108.9%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**

FBC states the 2 CP best reflects the cost causation of the system and therefore provides the most reasonable results. FBC submits that because the 12 CP provides results that do not create as large of a difference from the 2 CP results, the 12 CP approach would be the "next most reasonable." The 1 CP and 4 CP do not reflect the nature of the FBC system and the planning for facilities to meet peak loads because they do not consider the summer peak loads.[63]

KSCA argues that if the BCUC determines that the objective of the 2017 COSA Study is to achieve alignment of all the customer classes closer to 100 percent, then the BCUC should consider adopting the 12 CP model "in the interests of inter-class fairness and achieving the closest range of reasonableness." KSCA submits that weather in the FBC service territory does not follow a specific pattern and can vary from year to year, and within each year; therefore, a 12 CP model is more likely to capture the range of electrical consumption that is likely to occur, particularly by the residential class who is often most impacted by variations in weather patterns.[64]

FBC responds that KSCA's argument reflects a "further misunderstanding of the COSA process and results," pointing out that closer grouping of the results around the 100 percent R/C ratio may "look attractive," but is not a reason to justify its use. FBC submits that cost causation is the reason for the use of the 2 CP based on planning and use of the system.[65]

Panel Determination

The Panel finds that use of the 2 CP allocator is the most appropriate allocator for production and transmission rate base because it best reflects cost causation. **The Panel therefore accepts FBC's approach presented in the COSA Study and declines KSCA's request to direct FBC to change to the 12 CP allocator.**

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[63] Exhibit B-21, BCUC IR 115.2.

[64] KSCA Final Argument, p. 24.

[65] FBC Reply Argument, p. 72.

3.2.5 Overall Panel Determination on 2017 COSA Study

Based on the evidence in the proceeding and in consideration of the arguments made by the parties, the Panel finds the 2017 COSA Study results reasonable and accepts the 2017 COSA Study as the basis for FBC's rate rebalancing and rate design proposals. A number of issues were raised by interveners regarding the 2017 COSA Study, which have been addressed in the above sections of this Decision. Overall, the method and results of the 2017 COSA Study are consistent with the previous COSA study performed by FBC and the approach reflects cost causation. The Panel acknowledges there is a certain degree of judgment that must be applied when conducting a COSA study which can lead to more than one option for treatment of certain items. In these cases, FBC has provided adequate reasoning and evidence to support its chosen treatment.

3.3 Rate Rebalancing and Range of Reasonableness

The 2017 COSA Study is used to determine the ideal allocation of costs between customer classes, based on the current actual costs and their causation between customer classes. However, current rates were based on the costs prevailing at the time of the previous COSA study, and changes such as the relative demand of customer classes may have taken place since the last COSA study. Therefore, it is necessary to consider whether rates need to be rebalanced so that today's costs are properly allocated between customer classes.

As explained above, the 2017 COSA Study identifies the costs that should ideally be recovered from each customer class to meet Bonbright's second principle regarding the apportionment of costs on the basis of causation. This is evaluated using the revenue-to-cost ratio, i.e. the revenues from a given customer class at current rates, divided by the costs allocated to that customer class. In theory at least, a revenue-to-cost ratio of 100 percent (also referred to as unity) indicates that a customer class is being charged rates which are sufficient to recover the costs caused by that customer class, and no more.

However, in practice a COSA study is imprecise, being subject to "assumptions, estimates, simplifications, judgements and generalizations."[66] Hence, it is common practice for utilities to establish a range of reasonableness (RoR) around the ideal revenue-to-cost ratio of 100 percent. The meaning and use of this RoR is subject to some dispute in this proceeding.

The 2017 COSA Study has determined that the R/C ratios for FBC's customer classes are as follows: [67]

[66] Exhibit B-1, p. 54.
[67] Exhibit B-1, Table 5-11, p. 54.

Table 6: 2017 COSA Study 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%

The 2009 COSA Study provided the following results:[68]

Table 7: 2009 COSA Study Revenue to Cost Ratios

Rate Class	Ratio
Residential	98.3%
Small General Service (20)	113.4%
General Service (21)	138.9%
Large General Service Primary (30)	122.4%
Large General Service Transmission (31)	109.9%
Large General Service Transmission TOU (33)	23.5%
Lighting	81.9%
Irrigation	78.6%
Kelowna Wholesale*	89.9%
Penticton Wholesale	78.0%
Summerland Wholesale	96.6%
Grand Forks Wholesale	68.1%
BC Hydro Lardeau Wholesale	101.8%
BC Hydro Yahk Wholesale	103.5%
Nelson Wholesale	80.0%
Total	**100.0%**

FBC considers that an appropriate RoR for the revenue-to-cost ratios in the current proceeding is 95 to 105 percent.[69] This is based on past practice and prior BCUC proceedings, including the 2009 COSA and RDA.[70]

[68] FBC Application for Approval of a 2009 Rate Design and Cost of Service Analysis, Exhibit B-1-1, p. 43.

FBC proposes to rebalance only the Large Commercial Transmission and the Lighting customer classes (RS 31 and RS 50 respectively), since only these two rate schedules fall outside the 95 to 105 percent range of reasonableness. FBC submits this will reduce the revenues from RS 31 and increase the revenues from RS 50, while leaving all other customer classes' rates unchanged in the rebalancing. Further, FBC proposes that the rebalancing should be designed to move both rates to the closest endpoints of the range of reasonableness. This proposal would result in the changes provided in the following table:[71]

Table 8: Rebalancing 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%

Revenues from RS 50 would be increased by $155,822 (5.4 percent), and revenues from RS 31 would be reduced by $155,822 (2.2 percent). As a result, the R/C ratio of RS 31 would decline from 107.0 percent to 104.7 percent, and the R/C ratio of RS 50 would rise from 92.2 percent to 95 percent.

In BCUC IR 20.2.2, the BCUC asked FBC to calculate the effect of setting the rate for RS 50 to achieve a revenue-to-cost ratio of 100 percent, allocating the resulting revenues to reduce the rate for RS 31, and leaving all other rates unchanged. FBC's response was that the rate for RS 31 would be reduced such that it would achieve a revenue-to-cost ratio of 103.4 percent, down from its present ratio of 107.0 percent. FBC calculates that as a result of this rebalancing of revenues between RS 31 and RS 50, RS 50 rates would increase by 8.4 percent and RS 31 rates would decrease by 3.4 per cent.[72] FBC adds that since the rate increase for RS 50 in this situation would be less than 10 percent, it does not consider "rate shock" to be a consideration.

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[69] Exhibit B-1, p. 55.
[70] Ibid., p. 55.
[71] Ibid., Table 5-12, pp. 55-56.
[72] Exhibit B-8, BCUC IR 20.2.2.

FBC also provides the changes that would be required to rebalance all customer classes to unity:[73]

Table 9: Impacts of Rebalancing all Customer Classes to Unity

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

Positions of the Parties

FBC considers a range of reasonableness is warranted, since the 2017 COSA Study necessarily involves assumptions, estimates, simplifications, judgements and generalizations. It observes that a range of reasonableness is widely used in practice to evaluate specific R/C ratios, and to determine whether rate rebalancing is needed.[74]

FBC interprets the range of reasonableness as meaning that an R/C ratio falling between 95 and 105 percent "indicates that the revenues recovered from customers on that rate schedule are adequately recovering the allocated cost to serve them."[75] FBC argues that rates may need to be rebalanced if the associated R/C ratio falls outside the RoR.[76]

The CEC argues a pre-established range of reasonableness is arbitrary, adds no value, and detracts from the BCUC's consideration of the R/C ratios themselves,[77] which the CEC believes to be the best evidence available with regards to fair cost allocation between customer classes.[78] It adds that the range of reasonableness endpoints (95 percent and 105 percent in this case) should not be treated as fact since they have no statistical foundation. The CEC submits the BCUC should consider full rebalancing at every COSA and RDA,[79] although it acknowledges the range of reasonableness may judiciously be applied in the determination of "whether and when" to rebalance rates.[80]

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[73] Exhibit B-13, CEC IR 21.3.
[74] Exhibit B-1, p. 54.
[75] Ibid., p. 55.
[76] FBC Final Argument, p. 14.
[77] CEC Final Argument, p. 12.
[78] Ibid., p. 10.
[79] Ibid., p. 16.
[80] Ibid., p. 11.

The CEC recommends the BCUC deny FBC's request to rebalance to the end points of the range of reasonableness and require FBC to rebalance its customer classes to unity. The CEC argues the BCUC should use the "best information available," i.e. the 2017 COSA Study cost allocations and associated R/C ratios, and then carefully evaluate and weigh any other considerations. The CEC also states the BCUC should consider the consistency of the R/C ratios over time, and whether certain customer classes have R/C ratios which are consistently under or over 100 percent.[81]

BCOAPO submits that FBC's proposed range of reasonableness is acceptable, if it is interpreted properly. BCOAPO's understanding of the range of reasonableness is that all customer classes falling within the range should be equally viewed as having rates which "fairly recover the costs to serve them", and hence changing rates to move such R/C ratios to 100 percent would not improve the fairness of the rates. BCOAPO submits that FBC uses an appropriate approach in its proposed rebalancing.

ICG notes that in previous decisions, the BCUC has decided that when the R/C ratio of one or more customers is outside the range of reasonableness, then all customer classes should have their rates rebalanced to unity. ICG argues that, since at least one customer class has an R/C ratio outside the range of reasonableness, FBC should rebalance all its customer classes such that they all have R/C ratios of 100 percent. It submits that this is consistent with BCUC decisions on FBC's 2007 COSA and RDA (Order G-130-07) and the 2009 COSA and RDA (Order G-156-10).[82]

BCSEA-SCBC supports FBC's proposed rate rebalancing.[83]

No interveners questioned FBC's proposal for how revenues would be reassigned between RS 31 and RS 50 in the event that those were the only two rate schedules to be rebalanced.

FBC, in reply, states a range of reasonableness is both necessary and accepted industry practice, given that COSA study results are not "precisely accurate." It adds that the range of reasonableness may be used as a guideline when determining whether to rebalance rates, and also that when rates are rebalanced, this should be done such that the R/C ratio is moved to the closest endpoint of the range "as the COSA results provide no evidence to justify further rebalancing."[84]

FBC adds that rebalancing rates such that their R/C ratios are 100 percent would be "inconsistent with the ROR concept" and rebalancing should be to the nearest endpoint of the range of reasonableness, since the 2017 COSA Study results provide "no evidence to justify further rebalancing."[85]

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[81] CEC Final Argument, p. 13.
[82] ICG Final Argument, pp. 1819.
[83] BCSEA-SCBC Final Argument, p. 2.
[84] FBC Reply Argument, p. 80.
[85] Ibid., pp. 80–81.

Panel Determination

The Panel directs FBC to rebalance the Lighting customer class (RS 50) and the Large Commercial Transmission customer class (RS 31) as follows: rebalance RS 50 to achieve a revenue-to-cost ratio of 100 percent and allocate the resulting revenues to RS 31.

In providing this direction, the Panel considers the following rebalancing issues: (i) the use of the range of reasonableness; (ii) which customer classes are to be rebalanced; (iii) what is the appropriate target for rebalancing; and (iv) what specific changes are to be made to revenues.

In addition, we consider when rates should next be reviewed for rebalancing.

Use of the Range of Reasonableness

The Panel finds it appropriate to use a range of reasonableness of 95 to 105 percent for revenue-to-cost ratios when considering which customer classes to rebalance, but does not find that the endpoints of the range of reasonableness provide appropriate targets for rebalancing.

There is general agreement among the parties that a range of reasonableness has some purpose. The Panel notes that even the CEC submits that the range of reasonableness has a role in determining whether and when to rebalance rates, while arguing it is arbitrary and adds no value. On this basis, the Panel finds that a range of reasonableness for R/C ratios shall be established and used in this proceeding. However, the issue the Panel must consider is how to best use this range of reasonableness with deference to the Bonbright principles regarding the apportionment of costs on the basis of cost causation and the importance of rate stability.

The first issue is the appropriate breadth of the range of reasonableness. The Panel notes that FBC has proposed a range of reasonableness for R/C ratios of 95 to 105 percent and justifies the adoption of this range based on its acceptance in prior BCUC decisions, and because no other party has suggested a different range. The Panel also notes that none of the parties have raised concerns with the breadth of this range, nor have they proposed the use of an alternative range. Therefore, the Panel finds that a range of reasonableness of 95 to 105 percent for FBC continues to be appropriate, as this range is consistent with past BCUC decisions on FBC's range of reasonableness and there have been no changes in circumstance which indicate that a widening (or narrowing) of the range is required at this time.

The Panel recognizes that, in theory at least, an R/C ratio of 100 percent indicates that a customer class is fully covering its cost of service at a certain point in time, and no more. If this could be validated it would follow that all customer classes would have R/C ratios of 100 percent, because this would most closely meet Bonbright's principle that a utility's costs are apportioned fairly. However, as FBC has noted, the COSA study results are imprecise, being subject to various assumptions, estimates and judgements. Thus they can be described as merely approximations and even when an R/C ratio is reported as being 100 percent, it is not certain that the customer class is indeed fully covering its costs. However, while FBC has made this statement it has provided minimal evidence in support of this statement and has provided no analysis as to the magnitude of the margin of error. Thus, all that can be said is that in theory, the further the R/C ratio is from 100 percent, the greater the likelihood that the customer class is under- or over-recovering its allocated costs.

Given this uncertainty, the Panel finds that where a customer class has an R/C ratio within the range of reasonableness, there is insufficient evidence to conclude that the rate needs to be rebalanced. This is not to say that such a customer class is proven to be fully covering its costs, but rather, there is insufficient evidence it is not doing so. In the interests of another Bonbright principle, rate stability, where there is insufficient justification to rebalance rates, the Panel chooses not to rebalance them. Thus, the Panel agrees with FBC and most interveners, and finds that customer classes with R/C ratios inside the range of reasonableness do not require their rates to be rebalanced.

The Panel disagrees with ICG's position that if at least one customer class has an R/C ratio outside the range, then all customer classes must be rebalanced. In the Panel's view, given the inherent inaccuracy of the COSA study, there is only sufficient compelling evidence to rebalance the rates of those customer classes which have R/C ratios outside the range.

While BCOAPO agrees with the use of FBC's proposed range of reasonableness, it argues for the interpretation that all customer classes with R/C ratios within the range should be equally viewed as fairly covering their costs. The Panel disagrees with this interpretation of the evidence in this proceeding. Customer classes with R/C ratios within the range may all be treated as though they are equally covering their costs for practical purposes, but that is not the same thing as concluding that they are all covering their costs to an equal degree. As noted, FBC has provided only minimal evidence in support of its statement that COSA studies are imprecise. Therefore, the Panel is not persuaded the 2017 COSA Study provides sufficient evidence to draw this conclusion.

The biggest disagreement between the parties on the topic of the range of reasonableness is the use of the endpoints of the range as targets for rate rebalancing. FBC argues that the 2017 COSA Study results provide no evidence to rebalance a rate with an R/C ratio outside the range of reasonableness any further than the closest endpoint, whereas the CEC submits that the best evidence available is that rates should be rebalanced so that they have an R/C ratio of 100 percent, and thus the endpoints should not be used as targets for rate rebalancing. The Panel agrees with the CEC, for reasons which follow.

As the CEC argues, the costs allocated to each customer class in the COSA study provide the only specific evidence of the revenues that should be collected from the customer class to achieve fairness when considering Bonbright's principle of cost causation. The endpoints of the range of reasonableness provide no such evidence. FBC justifies the adoption of the 95 to 105 percent endpoints to the range based on their acceptance in prior BCUC decisions, not based on the endpoints having been calculated on a statistical or other rigorous basis. As the Panel has already noted, in theory the further an R/C ratio is from 100 percent, the more a customer class can be considered likely to be under- or over-recovering. Thus, the endpoints of the range are inherently less compelling as rebalancing targets than an R/C ratio of 100 percent. Moreover, if an endpoint were to be chosen it would increase the likelihood that a customer class may drift away from the range compared to if the customer class was at unity or the middle of the range. Given these reasons, the Panel finds that the endpoints of the range of reasonableness do not provide appropriate targets for rate rebalancing in this instance.

Which customer classes are to be rebalanced?

The Panel agrees with FBC and finds that the Large Commercial Transmission and Lighting customer classes (RS 31 and RS 50, respectively) should have their rates rebalanced**.** Both these customer classes have R/C ratios outside the range of reasonableness, which provides sufficiently compelling evidence that they are respectively over- and under-collecting their costs using the current rates.

All customer classes other than RS 31 and RS 50 have R/C ratios within the range of reasonableness, although none have ratios of exactly 100 percent. Thus, the Panel has insufficient evidence that the rates of these customer classes demand rebalancing, and in the interests of rate stability, the Panel does not find it reasonable to rebalance these rates.

What is the appropriate target for rebalancing?

The Panel agrees with the CEC that an R/C ratio of unity provides the best evidence that a customer class is fully recovering its costs and no more. Rates set to achieve R/C ratios of 95 percent or 105 percent, the endpoints of the range of reasonableness, are inherently less likely to cover only the allocated costs of their respective customer classes. For this reason, the Panel finds that the rates of the Large Commercial Transmission and Lighting customer classes shall be rebalanced as close as possible to unity, with no rebalancing being applied to the other rate classes.

What specific changes are to be made to revenues?

The rebalancing of these two customer classes is to be achieved by increasing the rate for Lighting customers (RS 50) such that the customer class has an R/C ratio of 100 percent, and reallocating the increased revenues to reduce the rate for RS 31, the Large Commercial Transmission class.

The Panel acknowledges that the R/C ratio for RS 31 as a result of this rebalancing will not be exactly 100 percent. However, there is no rebalancing of revenues that would result in both RS 50 and RS 31 set to unity while leaving all other rate classes unchanged. Further, reducing the rate for RS 31 to have an R/C ratio of 100 percent and collecting the corresponding revenues from RS 50 would involve a much more significant increase to rates for RS 50, since the revenues associated with RS 31 are more than twice that of RS 50. Thus, the Panel is satisfied that the change described above is the most equitable one available, given the constraint of not rebalancing all customer classes to unity.

The Panel is persuaded that the rebalanced rates will be sufficiently more equitable to overcome any reduction in rate stability that arises for these two customer classes. That said, in making this decision, the Panel has considered whether the 8.4 percent increase in rates for the Lighting customer class is excessive. Generally, a 10 percent rate increase is the threshold at which “rate shock” is experienced. This is not the case here, and thus the Panel finds that the increase in rates for the Lighting customer class is reasonable.

When should rates next be reviewed for rebalancing?

Examination of the comparable customer classes in 2009 (the most recent COSA study prior to 2017) and 2017 shows:

Table 10: Comparison of 2009 and 2017 R/C Ratios before Rebalancing (%)

Customer class	2009	2017
Residential	98.3	98.4
Small General Service / Small Commercial	113.4	102.2
General Service / Commercial	138.9	104.7
Large General Service / Commercial Primary	122.4	104.0
Large General / Commercial Transmission	109.9	107.0
Lighting	81.9	92.2
Irrigation	78.6	92.2

Following the 2009 COSA Study, by Order G-156-10, the BCUC directed FBC to rebalance the rates for all its customer classes to unity. However, in every comparable case, since this rebalancing to unity, the customer classes have all moved away from unity, and in the same direction as they were away from unity in 2009.

While the deviation from unity does not, for the reasons outlined above, necessitate a more widespread rebalancing of rates than has been directed by the Panel, it is something that should be monitored. **Accordingly, we direct FBC to file with the BCUC a Cost of Service study by no later than December 31, 2020.** We are concerned that the R/C ratios will move outside the range of reasonableness before FBC's next planned rate design application, and a cost of service study in 2020 will provide the opportunity for a further rebalancing before customer classes move too far outside the range of reasonableness.

4.0 Rate Design

4.1 Changes to Fixed Cost Recovery

FBC proposes to make changes to the rate structures of some rate classes to allow for a consistent fixed cost or customer charge recovery level across rate classes. Noting that rate design for most utilities is based fundamentally on cost causation, FBC states that utilities in general have not adopted full recovery of fixed costs through fixed charges. This is because higher fixed cost recovery has a disproportionate impact on low-usage customers and can discourage energy efficiency investments by customers. However, FBC notes there are a number of emerging technologies and trends it has identified that are driving a change in customer requirements for utility service. These include the following:

- More affordable distribution generation technologies;
- Energy efficiency and other demand management technologies; as well as
- Electric storage technologies.

FBC states that these technologies when adopted tend to reduce or change customer consumption patterns, requiring utilities to acquire new technologies or information systems to manage their systems. These have the potential effect of simultaneously increasing costs and /or reducing consumption. Thus, elements of the current rate design paradigm are potentially less well positioned for the future, where customers have more cost-effective options to generate electricity onsite or improve energy efficiency of their homes or businesses.[86]

FBC states that utilities must be able to raise rates to recover what are largely fixed costs as customers reduce their total energy use or total use of energy supplied by utilities. The current problem results from the way in which rates are set, with the inequitable impact on customers a consequence of the mismatch between the way costs are incurred and recovered. For example, net metering customers have a high percentage of fixed costs for delivery capacity that is still required even if they generate a substantial portion of their energy requirements, yet such costs are recovered on a volumetric basis. Therefore, as described by FBC:

> The potential for the lack of equitable treatment between different customers arises from the fact that those customers that have the desire, ability and financial capacity to adopt the energy management technologies noted above still require a utility connection and continue to use the FBC system, despite the ability to avoid some or all of the expected charges that underpin the current rates.[87]

FBC, as an example, explains that a customer with distributed generation requires grid connection to balance consumption and generation and provide energy when its generation facility is not producing and under current net metering provisions may result in no revenue or only partial recovery where the customer is not part of the net metering program. This raises the issue that the costs of maintaining infrastructure to deliver energy when needed, needs to be recovered from customers in general leading to general rate increases.[88]

Citing a report provided by a BCUC consultant in FEI's 2016 rate design proceeding, FBC explains that an increased share of fixed charges in fixed cost recovery is a recent utility rate design approach that better aligns revenue recovery with cost causation and serves to mitigate effects of disruptive technologies that lead to cost recovery challenges. As an example, the OEB's new policy, to be effective in 2019, will have rates structured to allow all costs for distribution service to be collected by electricity distributers in a fixed monthly charge. According to the OEB policy, this will allow for greater revenue stability for these distributers while enabling customers to leverage new technologies and better understand the value of the distribution service.

It is FBC's recommendation there be a minimum of 55 percent of customer-related unit costs and 65 percent of fixed infrastructure or demand-related costs 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 2017 COSA Study. FBC

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[86] Exhibit B-1, p. 29.
[87] Ibid., p. 30.
[88] Ibid., p. 30.

states that these minimum recovery levels are already in line with or exceed fixed cost recovery from many of FBC's rate classes and is not high enough to significantly impact those rate classes requiring a change. Therefore, as proposed, the changes will not affect all rate classes but will improve equity and consistency across all rate classes and is considered by FBC to be reasonable. FBC states that the proposed increase in the Customer Charge to a minimum of 55 percent of the 2017 COSA Study customer-related costs and the proposed increase to the demand-related charges as proposed will assist in the mitigation of the transfer of costs on both an inter-class and intra class basis.[89]

The current fixed cost recovery details are outlined in Table 11. The Customer Charge recovery percentage varies greatly among the various rate classes with Commercial and Wholesale Primary at the low end at 17 percent and 32 percent, respectively, and Large Commercial and Wholesale Transmission at the high end at 64 percent and 76 percent, respectively. There are no demand-related costs for either Residential or Small Commercial classes. Current demand-related costs as a percentage of the COSA unit costs range from 49 percent in Commercial to 98 percent for Wholesale Transmission.

Table 11: Current Fixed Cost Recovery[90]

	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]	8,222.83	32%	8.98	15.05	60%
Wholesale Transmission	5,974.48	7,892.14	76%	6.24	6.39	98%

Under the proposed changes to the Customer Charge, the Residential Customer Charge will increase from the current $16.05 to $18.70. This is to be phased in over a five year period in alignment with the move to a Flat rate which is addressed in Section 4.2.1 of this Decision. This amount is slightly above the median Customer Charge for a representative group of Canadian electric utilities and does not differ from what currently exists. FBC explains that this amounts to 53 percent of the associated fixed 2017 COSA Study costs which is below the 55 percent target, but is proposing this amount because it was the amount which was discussed within its

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[89] Ibid., p. 31; Exhibit B-1-4, p. 32; Exhibit B-21, BCUC IR 113.4.
[90] Exhibit B-1-4, Table 3-2, p. 32.

consultation process. FBC also explains that this increase will result in a small decrease in Tier 1 and Tier 2 if the RCR methodology is retained.[91] Table 12 provides a summary of the Fixed Charge changes that will result for all non-residential rate classes.[92]

Table 12: Summary of Proposed Fixed Charge Changes

<table>
<tr><th>Rate Class</th><th>Code</th><th>Current Customer Charge (($/mo)</th><th>Proposed Customer Charge ($/mo)</th><th>Change ($/mo)</th><th colspan="2">Current Demand Charge ($/kVA/mo)</th><th colspan="2">Proposed Demand Charge ($/kVA/mo)</th><th colspan="2">Change ($/mo)</th></tr>
<tr><td>Small Commercial</td><td>RS 20</td><td>19.40</td><td>23.00</td><td>3.60</td><td colspan="2">N/A</td><td colspan="2">N/A</td><td colspan="2">N/A</td></tr>
<tr><td>Commercial</td><td>RS 21</td><td>16.48</td><td>54.00</td><td>37.52</td><td colspan="2">7.72</td><td colspan="2">10.22</td><td colspan="2">2.50</td></tr>
<tr><td>Large Commercial Primary</td><td>RS 30</td><td>945.04</td><td>945.04</td><td>n/c</td><td colspan="2">9.19</td><td colspan="2">9.19</td><td colspan="2">n/c</td></tr>
<tr><td rowspan="2">Large Commercial Transmission</td><td rowspan="2">RS 31</td><td rowspan="2">3116.03</td><td rowspan="2">3195.00</td><td rowspan="2">78.97</td><td>Wires</td><td>PS</td><td>Wires</td><td>PS</td><td>Wires</td><td>PS</td></tr>
<tr><td>4.93</td><td>2.77</td><td>4.93</td><td>3.45</td><td>n/c</td><td>0.68</td></tr>
<tr><td rowspan="2">Wholesale Primary</td><td rowspan="2">RS 40</td><td rowspan="2">2645.03/POD</td><td rowspan="2">4522.46/POD</td><td rowspan="2">1877.43</td><td>Wires</td><td>PS</td><td>Wires</td><td>PS</td><td>Wires</td><td>PS</td></tr>
<tr><td>8.98</td><td>4.82</td><td>8.98</td><td>4.82</td><td>n/c</td><td>n/c</td></tr>
<tr><td rowspan="2">Wholesale Transmission</td><td rowspan="2">RS 41</td><td rowspan="2">5974.48</td><td rowspan="2">5978.48</td><td rowspan="2">4.00</td><td>Wires</td><td>PS</td><td>Wires</td><td>PS</td><td>Wires</td><td>PS</td></tr>
<tr><td>6.34</td><td>4.77</td><td>6.34</td><td>4.77</td><td>n/c</td><td>n/c</td></tr>
<tr><td>Irrigation</td><td>RS 60</td><td>20.06</td><td>22.09</td><td>2.03</td><td colspan="2">N/A</td><td colspan="2">N/A</td><td colspan="2">N/A</td></tr>
</table>

Positions of the Parties

FBC's position is that recovering fixed costs through fixed charges whether basic or demand charges is very much in alignment with Bonbright principles such as revenue stability and the fair apportionment of costs among customers. However, it acknowledges that this could be seen as being contrary to policies related to energy efficiency and conservation as it reduces the price signal in the remaining energy charges.[93]

With specific reference to residential customers, FBC asserts that most distribution costs are fixed on an annual basis and align well with economic fairness and cost causation. However, if Customer Charges are excessive they may be in conflict with efficient use of the system, as they would reduce the incentive for energy conservation in those cases where conservation enhances economic efficiency.[94]

BCOAPO states that it supports the principles of inter- and intra- class equity and accordingly supports the FBC proposals for the Customer Charge. BCOAPO observes that current Customer Charges for RS 01, RS 03, RS 03A and RS 20 are all below the 55 percent of 2017 COSA Study customer costs allocated to the classes. However, it supports FBC's 55 percent proposal as being reasonable, given the objective is to align fixed cost recoveries across customer classes. That said, BCOAPO disagrees with FBC's contention that the increase to the Customer Charge will have no effect on the consumption of electricity, but acknowledges this will be minor as a significant portion of a customer's monthly bill will be charged under variable rates.

BCOAPO also notes that the Customer Charge for RS 30 recovers 64 percent of customer-related costs, which is above the 55 percent target. To address this it suggests reducing the RS 30 customer charge. BCOAPO argues this would allow for a modest increase in the energy rate for this class and result in RS 30 energy charges being more closely aligned with FBC's long-run marginal cost (LRMC), as well as being in alignment with the

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[91] Ibid., pp. 67, 71; Exhibit B-8, BCUC IR 41.1, 41.2.
[92] FBC Final Argument, Table 1, p. 13.
[93] Exhibit B-8, BCUC IR 4.4.
[94] Exhibit B-8, BCUC IR 8.4.

Government's conservation policy and Bonbright Principle 3 (price signals that encourage efficient use and discourage inefficient use). Further, while being inconsistent with increasing fixed cost recovery, it does ensure fixed costs are applied evenly to all customer classes and thus, more equitably.[95]

The CEC also supports FBC's Customer Charge proposals, and points out that establishing minimum contribution levels is an improvement in terms of fairness and cost causation. The CEC observes the proposed changes are not overly burdensome to ratepayers and recommends the BCUC approve the fixed cost recovery proposals as proposed. With respect to RS 21, the CEC states that an increase in the fixed cost recovery of both the Customer Charge and the Demand Charge align with Bonbright Principles 1, 7, and 8 and will aid in the recovery of this rate class's share of cost of service, thereby improving rate stability. In addition, intra class equity is enhanced and inter class equity is unharmed. Further, with reference to RS 21, the CEC agrees that the existing two-tier block rate should be flattened. However, the CEC is concerned that 4.8 percent of RS 21 customers will have an annual bill impact that is greater than 10 percent. While FBC has indicated that it will work with these customers, the CEC is not satisfied, stating that "bill impacts of over 10% and several thousand dollars should not be dismissed with a determination to simply 'work with' the customers." The CEC's position is the BCUC's approval of the RS 21 proposal should be conditional on either offering a phase-in period or working with customers to ensure rate impacts are mitigated to a greater extent.[96]

Resolution acknowledges that the challenges related to fixed cost recovery will become more relevant and accentuated as alternative energy generation options become more popular, as will the ability to collect revenue from residential power sales with an increase in the size of these self-generation systems. Resolution states that for net metering accounts, other types of revenue collection should be explored.[97]

BCSEA-SCBC states that the rationale for FBC's residential fixed rate proposal is to achieve alignment between RS 01 (115,000 customers) and RS 03A (510 qualified farm customers). It submits that it is more appropriate to align the customer charge for RS 03A customers with the lower rate currently in place for RS 01 customers, noting that FBC intends to dissolve RS 03 and merge them in with RS 01. In determining its approach BCSEA-SCBC took into account the following:

- When combined with the volumetric charge the net impact will be revenue neutral;
- The lower customer charge benefits low-consuming customers while a higher charge has the opposite effect;
- A lower customer charge and higher volumetric charge provides a stronger price signal for both conservation and efficiency; and
- FBC's proposed increase to RS 01 is low enough so as not to result in major impacts or cross-subsidies that arise with extremely low or high customer charges.[98]

KSCA advocates a Customer Charge being derived from a methodology that differs from the minimum system study approach. This issue has been addressed in Section 3.2.1 and will not be repeated. However, with respect to the percentage of costs recovered, KSCA notes that in the most recent BC Hydro RDA Decision, the BCUC

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[95] BCOAPO Final Argument, pp. 40–41, 63.
[96] CEC Final Argument, pp. 4, 29–31.
[97] Resolution Final Argument, p. 4.
[98] BCSEA-SCBC Final Argument, pp. 22–23.

through Order G-5-17 left the percentage of recovery of customer-related costs at 45 percent.[99] KSCA cites the BCUC's belief that the issue was one of balance and there was no compelling need for change, as the basic charge was currently in a range similar to other utilities. KSCA asks the Panel to consider what has changed since the BC Hydro 2015 RDA Decision and Order G-5-17 issued in January 2017 that would cause the BCUC to change the merits of its position on not rising above 45 percent of fixed costs. In addition, the Panel is requested to consider the merits of the substantial Customer Charge differential that exists between BC Hydro and Nelson Hydro as compared to that of FBC.[100]

KSCA further states that "[b]etween 1997 and 2017 the actual COSA-determined Customer-Related per Unit Cost per month rose by 79.3%, from $19.86 to $35.60. In contrast, over the same twenty year period, the Commission ordered FBC to increase collection of the monthly per customer residential BCC from $6.67 per month to $16.05 per month, and, if this Commission panel accedes to FBC's application recommendation, this will be ordered to rise to $18.70 by 2023."[101]

KSCA recommends the following:

> In making its decision this Commission panel is asked to consider carefully the fact that the FBC BCC charge ordered set by the Commission has risen at a rate three times faster than the actual increase of the BCC costs to the Company itself, and that BC Hydro residential customers, just 14 km north of Kaslo, only pay 35.4% the amount that an FBC customer does to access their first kWh; a Nelson Hydro residential customer in Balfour, fifteen minutes south of Ainsworth, only pays 48.7% the cost to access that first kWh; and a Puget Sound Energy residential customer, based on the applied principles of Garfield and Lovejoy, under the jurisdiction, for example, of the WUTC, only pays 58.5% the amount to access that first kWh.[102]

AMCS/RDOS takes no definitive position on changing the residential basic charge. However, it notes that if changes were not made to the existing residential Customer Charge, the bill impact would be less than that of combining it with the proposed flat rate. AMCS/RDOS' position is that there is far greater urgency to the termination of the RCR than to raising the Customer Charge and, even if there is some cross subsidization resulting from keeping the rate below FBC's recommended $18.70, it would be minor as would any adverse impacts.[103]

In reply to KSCA's comparisons to other utilities, FBC cites a passage from the FBC Application for Approval of 2012–2013 Revenue Requirements and Review of 2012 Integrated System Plan Decision where the BCUC stated that FBC's responsibility is to provide for safe and reliable service in a cost-effective manner and to do so it must design and manage its system based on the needs of its customers and its available resources. The BCUC continued, stating that this "at times, may result in rates that are greater than those of BC Hydro and potentially times when they are less."[104] As to KSCA's preference for a Customer Charge that would favour low consumption

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[99] BC Hydro 2015 Rate Design Application, Order G-5-17 dated January 20, 2017 and decision, p. 22.
[100] KSCA Final Argument, p. 13.
[101] Ibid., p. 1.
[102] Ibid., p. 1.
[103] AMCS-RDOS Final Argument, pp. 1, 20–21.
[104] FBC Application for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan, Order G-110-12 dated August 15, 2012 and decision, pp. 20-21.

customers, FBC argues that these customers benefit from intra class subsidization occurring due to the under recovery of COSA-determined fixed costs which are collected through the energy rates of higher consuming customers.

FBC notes BCSEA-SCBC's position that the RS 01 and RS 03 Customer Charges be set at the current RS 01 level, but does not address the merits of BCSEA-SCBC's submissions.[105]

With respect to Commercial fixed charges, FBC notes that the CEC, BCOAPO and BCSEA-SCBC made submissions with respect to its proposal. The CEC and BCSEA-SCBC largely support FBC's Commercial proposals. Likewise no issues were raised by interveners with respect to Wholesale fixed customer charges.

FBC notes that BCOAPO's submissions indicate support for the RS 20 Customer Charge proposal, but that BCOAPO also suggests RS 30 Customer Charges be reduced due to the collection of an amount that is in excess of the target 55 percent. FBC does not agree, pointing out that this would represent a move away from cost causation principles, as the rate is still well below COSA unit costs. Moreover, any such change from that originally applied for should not occur without allowing for comment from RS 30 customers.[106]

With reference to the CEC's concerns with RS 21, FBC states it has not proposed to phase in the changes because the number of affected customers with increases over 10 percent is lower than 5 percent, noting this is the standard for recent residential rate structure changes. FBC continues to believe that management of bill impacts are best done through its existing Key Account managers working with individual businesses. However, if the BCUC is to determine that a phase-in period is warranted then it is suggested that this be accomplished by a compliance filing 30 days following the issuance of this Decision.[107]

Panel Determination

The Panel approves FBC's proposals for rate changes to the fixed Customer and Demand Charges for all rate classes as outlined in the Application.

The Panel notes that the changes FBC is proposing will be revenue neutral and are primarily designed to better match customer costs on a cost causation basis and to allow for a greater portion of fixed costs to be recovered through fixed charges, rather than those that are volumetric. [108] The Panel also notes that of the interveners who provided submissions on the proposed fixed cost changes, most are in support of the approach taken by FBC with respect to the recovery of fixed charges.

In the view of the Panel, the utility business is undergoing a period of change due to a customer trend to either reduce their energy requirements or their need for utility provided energy. This has been brought about by the availability of more cost-effective technologies designed to reduce energy consumption or provide more cost-effective self-generation options. The impact of these changes is an increasing potential for customers to lower their level of energy consumption thereby reducing their volumetric charges. Because of the magnitude of fixed

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105 FBC Reply Argument, pp. 34- 37.
106 Ibid., pp. 41–43.
107 Ibid., pp. 45–46.
108 Exhibit B-1, p. 33.

costs currently recovered through volumetric means, this results in an inequitable impact on other customers. Further, in all likelihood the level of inequity is likely to continue to increase moving forward as advancements in technology continue. Therefore, the Panel finds that the most equitable solution is to place greater reliance on the recovery of fixed costs through fixed charges and take steps to move toward greater harmonization between rate classes with respect to the percentage of fixed cost recovery. As noted by BCOAPO, the proposals put forward by FBC support the principles of inter and intra class equity and the Panel considers them a more appropriate methodology for fixed cost recovery. Moreover, for the most part, these changes can be achieved without undue burden being placed on ratepayers.

The Panel disagrees with BCOAPO's proposal to reduce the RS 30 customer charge so that the level of fixed cost recovery decreases from the current 64 percent to FBC's stated target of 55 percent. The Panel considers such a proposal to be a move away from the principle of cost causation and therefore finds such a proposal inappropriate.

Finally, with regard to KSCA's comments concerning the variances in residential customer charges for FBC as compared to other provincial utilities, the Panel agrees with FBC's citations from the FBC 2012-2013 Revenue Requirements Application Decision. In that decision, the BCUC favoured the treatment of utilities as unique with their individual set of circumstances requiring them to design and manage their systems based on the consideration of customer need and available resources. The Panel is not persuaded there is a need in this instance to require FBC to adopt rate structures of another utility when the circumstances faced by these utilities differ.

The Panel also approves FBC's proposal to phase in the customer charge for residential customers. While the changes in customer charges alone are unlikely to create a burden on residential ratepayers, when combined with the proposed changes to the RCR, the potential rate impacts are much greater. This is discussed further in Section 4.2.1.

With respect to a phase-in of RS 21 changes as proposed by the CEC, the Panel agrees. The fact that only 4.8 percent of RS 21 customers have a bill impact of over 10 percent is not the only issue, as the dollar impact also needs to be considered. In the view of the Panel, bill impacts of "several thousand dollars" as asserted by the CEC could be significantly burdensome to some businesses and needs to be addressed. **Therefore, the Panel directs FBC as part of its compliance filing to provide a proposal outlining a phase-in option of up to three years for those RS 21 customers that have been identified as having a bill impact greater than 10 percent as a result of changes to fixed charges.**

4.2 Residential Rate Design

FBC seeks the following approvals regarding the residential rate class:

1. Approval to decrease the differential between the Tier 1 and Tier 2 price such that after a period of five years the differential between the Tier 1 and Tier 2 price will be zero, resulting in a flat rate.
2. Approval to adjust the Customer Charge over the course of five years such that at the beginning of year five the Customer Charge under RS 01 will be equal to the Customer Charge under RS 03A (Residential Exempt Rate for Farm Customers).
3. Approval to re-open the optional Time of Use rate for residential customers while also re-structuring the rate.
4. Approval to remove RS 03 (RCR Control Group) from the Electric Tariff.

FBC's request regarding the residential customer charge is addressed above in Section 4.1 of this Decision. The other three proposals are discussed in the following sections.

4.2.1 Residential Conservation Rate vs Flat Rate

FBC requests approval to implement a flat rate structure as the default rate for residential service and to phase in this change from the existing two-tier Residential Conservation Rate (RCR) over four years (i.e. at the beginning of the fifth year the rate would be flat).

FBC also proposes increasing the Customer Charge by $2.65 per month to $18.70 in order to increase the proportion of fixed costs that are recovered by this charge. This request has been approved in Section 4.1 of the Decision. Table 13 provides a comparison of the current RCR at 2017 rates and the proposed flat rate at the end of the phase-in period.

Table 13: Comparison of RCR vs Flat Rate

Rate Element	Current RCR (2017 Rates)[109]	Proposed Flat Rate[110]
Customer Charge	$16.05	$18.70
Threshold (kWh)	800	N/A
Block 1 Rate (per kWh)	$0.10117	$0.11749
Block 2 Rate (per kWh)	$0.15617	

[109] Exhibit B-1, Table 6-1, p. 58.
[110] Ibid., Table 6-10, p. 73.

FBC proposes phasing in the new residential rate over five years, as shown in the following table.

Table 14: Proposed Phase-in of Flat Rate[111]

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%

Residential Rate Options Considered

Following the publication of the BCUC RIB Rate Report, BC's Minister of Energy and Mines (the Minister) sent a letter to BC Hydro and FBC requesting that the utilities examine a range of alternative rate designs with price signals for energy efficiency and electrification.[112] FBC notes that the proposal for a transition from the existing RCR to a flat rate structure may promote the use of electricity for various residential uses (including home electric vehicle charging) and therefore serve electrification objectives as requested in the Minister's letter.[113]

FBC examined the following options for a new residential rate:[114]

- a standalone rate for customers without access to natural gas service;
- changing the RCR in a number of ways including:
  - changing the Tier 2 threshold;
  - decreasing the difference between Tier 1 and Tier 2 rates;
  - a seasonal threshold;
- a declining block rate;
- optional TOU;
- a return to a flat rate;

[111] Exhibit B-1, Table 6-10, p. 73.
[112] Ibid., pp. 18-19; Appendix J.
[113] Exhibit B-8, BCUC IR 4.2.
[114] Exhibit B-1, pp. 59-60.

- changes to the Customer Charge including:
    - increase to equal RS 03;
    - increase toward COSA unit cost;
    - reduce or eliminate.

Rationale for the Proposed Flat Rate

FBC states the following: "Cost causation is a key consideration for the Company in evaluating rates. Other principles, such as customer understanding and acceptance, encouraging efficient use, and revenue and rate stability are desirable, provided that the general principle of cost causation is not unduly compromised."[115]

FBC provides the following arguments in support of its proposal to transition to the flat rate:

- The lack of a cost basis for the existing RCR – the Tier 1 and Tier 2 energy rates were initially set to achieve a desired result (i.e. lower residential class energy use) within a constraint linked to the annual bill impact to customers. There is no particular relationship between the level of the existing rates and any cost basis.[116]
- Ease of understanding – surveys show that customers find a flat rate structure to be easiest to understand and that ease of understanding and customer acceptance are ranked most highly by residential customers.[117]
- Conservation achieved during the five-year RCR period has been embedded in the forecast residential load. Additional conservation is likely subject to diminishing returns and may create inequity amongst customers with regard to the ability to take steps to reduce consumption.[118]
- FBC agrees with certain customers' sentiment that the impact of the RCR has become overly burdensome on high consuming customers, while noting that the BCUC has determined that it does not find that the RCR causes a subsidy between customers in areas with and without access to natural gas.[119]

FBC states that inclining block rate structures may provide better price signals for energy conservation for some segments of residential customers, but that inclining block rate structures provide less desirable results in terms of other rate design considerations such as customer awareness and understanding, cost causation or rate and revenue stability. FBC also states that compared to flat rates, inclining block rates may provide less rate stability for customers because the impact of volume variances on revenue and rates can be more significant than variances under flat rates.[120]

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[115] Exhibit B-1, p. 60.
[116] Ibid., p. 71.
[117] Exhibit B-8, BCUC IR 3.1.
[118] Exhibit B-1, p. 72.
[119] Ibid., p. 61.
[120] Exhibit B-8, BCUC IR 3.3.

In response to CEC IR 31.3, FBC stated: "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."[121]

FBC was asked in BCSEA-SCBC IR 16.1 to update Table 3-2 from the 2014 RCR Report which provided an estimate of the percent and GWh savings resulting from implementing the RCR. FBC responded that it has not measured the elasticity factors since the 2014 RCR Report and cannot provide an update to the table.[122] FBC further stated in response to BCSEA-SCBC IR 16.2 that it has not estimated the savings associated with the RCR since 2014 but it would not expect to see a large increase beyond the amount measured in 2014. FBC further stated it does not expect the estimated savings achieved to be reversed as a result of phasing out the RCR because much of the conservation expected from the RCR is a result of changes in appliances/fixtures that would not be removed as FBC phases in the flat rate.[123] FBC did not estimate the percent or GWh increase in consumption which may result from implementing the flat rate.[124]

FBC modelled a limited number of RCR options for discussion at the July 2017 open houses based on suggestions received in June 2017 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). FBC states that 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 states that no measure of its LRMC of power is close to the current 2017 Tier 2 rate of $0.15617 per kWh.[125]

Bill Impacts of Moving to the Flat Rate and Increasing the Customer Charge

The following table shows the customer bill impact of moving immediately from the RCR to the flat rate, excluding the impact of the proposed increase to the fixed customer charge. The table shows that as a result of moving to the flat rate, 76.4 percent of customers will experience a bill increase. The table also compares the aforementioned bill impacts to the bill impacts which resulted from the move from a flat rate to the RCR in 2012.[126]

[121] Exhibit B-13, CEC IR 31.3.
[122] Exhibit B-24, BCSEA-SCBC IR 16.1.
[123] Ibid., BCSEA-SCBC IR 16.2.
[124] Ibid., BCSEA-SCBC IR 16.3.
[125] Exhibit B-1, p. 65.
[126] Exhibit B-8, BCUC IR 35.2.1.

Table 15: Bill Impact of Moving Immediately to Flat Rate (Excluding Customer Charge Proposal)

		Table 2-1 from 2014 RCR Report			2017 RDA	
	Bill Impact	# Records	Percent of Total		# Records	Percent of Total
Bill Increase	Above 20%	396	0.4%			
	15% - 20%	1,894	2.0%		1,898	2.1%
	10% - 15%	5,681	6.0%		40,794	45.5%
	5% - 10%	9,816	10.3%		14,233	15.9%
	0% - 5%	12,072	12.7%		11,536	12.9%
Bill Decrease	0% - 5%	13,645	14.4%		9,020	10.1%
	5% - 10%	20,423	21.5%		7,231	8.1%
	10% - 15%	31,002	32.7%		3,684	4.1%
	15% - 20%				1,105	1.2%
	Above 20%				160	0.2%
		94,929	100%		89,661	100%

The following table shows the customer bill impact of moving immediately from the RCR to the flat rate and increasing the fixed customer charge.[127]

Table 16: Bill Impact of Moving Immediately to Flat Rate (Including Customer Charge Proposal)

	2017 RDA		
	Bill Impact	# Records	Percent of Total
Bill Increase	Above 20%	0	0.0%
	15% - 20%	35,564	39.7%
	10% - 15%	13,402	14.9%
	5% - 10%	9,855	11.0%
	0% - 5%	9,204	10.3%
Bill Decrease	0% - 5%	8,461	9.4%
	5% - 10%	7,149	8.0%
	10% - 15%	4,204	4.7%
	15% - 20%	1,470	1.6%
	Above 20%	352	0.4%
		89,661	100%

[127] Exhibit B-21, BCUC IR 120.2.

FBC also provided the bill impacts of an immediate move to a flat rate, along with an immediate increase to the customer charge:[128]

Table 17: Average Bill Impact of Immediate Move to Flat Rate and Increased Customer Charge

Annual Consumption	Percent of Total Customers	Average Annual Current Bill	Average Bill Difference (%)	Average Annual Bill Difference ($)
Above 35,000	2%	$ 8,849	-18%	-1,616
30,000 - 35,000	1%	$ 4,697	-15%	-687
25,000 - 30,000	2%	$ 3,911	-13%	-493
20,000 - 25,000	5%	$ 3,131	-10%	-301
15,000 - 20,000	10%	$ 2,359	-5%	-112
10,000 - 15,000	22%	$ 1,602	4%	63
5,000 to 10,000	37%	$ 961	14%	131
0 to 5,000	21%	$ 511	16%	83
Percent of Customer with Annual Bill Increase			76%	
Percent of Customers with Impact Below 10%			45%	

FBC stated in response to BCUC IR 46.2 that the minimum number of years over which customers could transition to the flat rate without experiencing annual bill increases of more than 10 percent would be two years; however, this would result in rate increases of almost 8 percent in two consecutive years, which FBC considers rate shock given the short time frame. FBC states that it considers that a number of successive increases below 10 percent may cause similar hardship and that phase-in periods of two or three years still result in relatively large increases in each year.

Maintaining a Two Tier RCR Structure

FBC was asked in BCUC IR 38.12 to provide a proposal for adjusting the RCR under a hypothetical scenario where FBC was directed to continue using the RCR as opposed to moving to a flat rate.

FBC responded that any "combination of rates contained in an RCR can be considered arbitrary when viewed from a cost-causation perspective." However, FBC stated that one approach would be to "rely on a return to the principles and rate characteristics approved by Order G-3-12," which are as follows:

- No more than 5 percent of customers would experience rate impacts greater than 10 percent as a result of the implementation;
- A Tier 1 to Tier 2 rate differential of 44 percent, as initially approved; and
- Revenue neutrality with the current rates.[129]

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[128] Exhibit B-8, BCUC IR 46.1.
[129] Ibid., BCUC IR 38.12.

FBC added a further characteristic to the above list, which is the proposed increase to the Customer Charge.[130]

Based on these principles, FBC provided the following table outlining the hypothetical rate:

Table 18: Hypothetical RCR and Annual Bill Impact Compared to Current RCR

	Current RCR	Example Rate	
Customer Charge ($/mo)	16.05	18.70	
Tier 1 Rate ($/kWh)	0.10117	0.10175	
Tier 2 Rate ($/kWh)	0.1562	0.14652	
Threshold	800	800	
	Annual Bill Impact		
Annual Consumption	**Percent of Customers**	**Percent**	**Dollars**
Above 35,000	2%	-5%	-415
30,000 - 35,000	1%	-4%	-181
25,000 - 30,000	2%	-3%	-132
20,000 - 25,000	5%	-3%	-84
15,000 - 20,000	10%	-2%	-37
10,000 - 15,000	22%	1%	8
5,000 to 10,000	37%	3%	33
0 to 5,000	21%	7%	37
Percent >10%		3%	

FBC stated that if the BCUC were to direct a "rebasing" of the RCR according to the principles set out in the FBC 2012 RIB Rate Decision and Order G-3-12, FBC would have a concern over the level of the Tier 2 rate relative to the LRMC of new electricity supply and would likely consider and propose some method of applying rate increases only to the Customer Charge and Tier 1 Rate.[131]

Positions of the Parties

BCSEA-SCBC supports retention of the RCR. It submits that the RCR has achieved substantial amounts of conservation and efficiency, which FBC does not deny. It submits that "going forward, the conservation and efficiency purpose of the RCR remains as important as ever and it continues to be fully supported by legislated energy policy objectives and is consistent with the Bonbright principles."[132]

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[130] Exhibit B-8, BCUC IR 38.12.

[131] Exhibit B-21, BCUC IR 121.1.

[132] BCSEA-SCBC Final Argument, p. 4.

BCSEA-SCBC also argues that in its view "there has been no diminishment of the policy objective to reduce electricity consumption through conservation and efficiency measures…Wasting clean renewable electricity by failing to implement cost-effective conservation and efficiency measures is a hindrance to low carbon electrification."[133]

AMSC/RDOS requests the immediate termination of the RCR and return to the flat rate.[134] It argues that the RCR violates at least four Bonbright Principles: Principle 2 – Fair apportionment of costs among customers; Principle 3 – Price signals that encourage efficient use and discourage inefficient use; Principle 6 – Rate stability; and Principle 8 – Avoidance of undue discrimination.[135]

With regard to Principle 2, AMCS/RDOS argues that under the RCR, customers with more than 36 percent of their consumption in Tier 2 pay average rates that are above a cost-based flat rate, while those with less consumption in Tier 2 pay average rates below cost. AMCS/RDOS further asserts that 20 percent of customers are paying rates above cost and 80 percent of customers are paying rates below cost.[136]

With regard to Principle 3, AMCS/RDOS argues that the fundamental rationale for residential inclining block rates should be to satisfy this principle, yet the RCR does not. In support of this assertion, AMCS/RDOS submits that 58 percent of FBC's customers use less than 10,000 kWh per year and, on average, have little or no consumption above the Tier 2 Threshold. These customers are deciding on their energy efficiency investments based on 10.1 cents/kWh, which is 16 percent below the flat rate. In effect, they are being encouraged to over-consume electricity. Conversely, customers with significant consumption in Tier 2 are deciding on their energy efficiency investments based on 15.6 cents/kWh, which is 30 percent above the flat rate. These customers are being encouraged to under-consume electricity.[137]

With regard to Principle 6, AMCS/RDOS states: "Electric heat customers experience enormous fluctuations in their electricity rates throughout the year and major rate fluctuations will continue until the end of FBC's phase-out period."[138]

With regard to Principle 8, AMCS/RDOS argues that the RCR "[u]nfairly discriminates by charging some customers higher rates than others, where there is no economic or environmental justification for the differential."[139]

AMCS/RDOS further argues that the RCR is encouraging customers to use natural gas, propane or heating oil instead of electricity and that is clearly contrary to the CEA and the BC Government's policy to reduce GHG emissions.[140]

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[133] BCSEA-SCBC Final Argument, pp. 10-11.
[134] AMCS/RDOS Final Argument, p. 1.
[135] Ibid., pp. 3-12.
[136] Ibid., p. 3.
[137] Ibid., pp. 5–6.
[138] Ibid., p. 8.
[139] Ibid., p. 10.
[140] Ibid., p. 18.

KSCA requests that FBC retain the RCR with the proviso that any adjustments to the Tier 1 and Tier 2 rates be made in accordance with the criteria outlined in the FBC 2012 RIB Rate Decision and Order G-3-12.[141]

The CEC submits that BCSEA-SCBC has provided "credible evidence of continuing effectiveness and a valid threshold [for the Tier 2 rate], and that FBC has provided significant evidence of customer dissatisfaction." The CEC also notes that there is always a conservation incentive when there is a variable charge, even under a flat rate structure. The CEC recommends that the BCUC request FBC to continue to conduct further customer awareness and understanding activities should the BCUC decide to continue with the RCR. Should the BCUC determine that it is best to move to a flat rate, the CEC recommends the BCUC approve FBC's proposal.[142]

BCOAPO disagrees with FBC's characterization of Bonbright Principle 3 as being "mainly intended to provide appropriate price signals to customers for efficient use of the electric system." BCOAPO's view is that the principle is aligned with the concept of economic efficiency. BCOAPO submits that the LRMC was a consideration in the FBC 2012 RIB Rate Decision but that the BCUC was limited in using it to set the Tier 2 rate because of insufficient information, and that this lack of information still exists. Despite this, BCOAPO supports FBC's proposed phase-in of the flat rate.[143]

Resolution "urges" the BCUC to reject FBC's proposed transition to a flat rate and argues that the RCR should be maintained for the following reasons:

- The two-tier billing structure provides the financial stimulus to encourage consumers to implement greater energy efficiency measures;
- Moving to a flat rate will adversely affect low energy consuming ratepayers;
- The RCR billing mechanism provides a "quasi-seasonal charging mechanism" which is of great value for recovering costs from customers with low summer and high winter energy profiles;
- Smaller solar installations would be impacted under a flat rate, making it less financially beneficial to install;
- There is no evidence of cross-subsidization under the RCR; and
- Investments made up front at the construction stage of homes in more expensive energy efficient technologies will be evaluated against the "comfort and financial benefit" the investment returns over the long term. This financial consideration could potentially be weakened for the case of adopting high efficient technologies under a flat rate due to financial payback being potentially longer.[144]

Gabana argues for an immediate return to the flat rate.[145]

BCMEU supports FBC's proposals regarding transitioning to the flat rate.[146]

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[141] KSCA Final Argument, p. 1.
[142] CEC Final Argument, p. 22.
[143] BCOAPO Final Argument, pp. 35–50.
[144] Resolution Final Argument, pp. 1–6.
[145] Gabana Final Argument, p. 1.
[146] BCMEU Final Argument, pp. 1–2.

FBC does not agree that BCSEA-SCBC has accurately described the drivers of the residential rate proposals provided in the Application. FBC reiterates the following reasons for implementing a flat rate which were originally cited in the Application:

- The primary driver is the lack of a cost basis for the existing RCR;
- Additional conservation is likely subject to diminishing returns;
- Continuing with the RCR may create inequity amongst customers with regard to the ability to take steps to reduce consumption; and
- With respect to other principles and objectives, when considered alongside the current RCR, FBC's proposal is likely to lead to greater customer acceptance and understanding of the default rate that the utility has in place, and less reliance on alternate fuel sources with higher environmental impacts.[147]

FBC argues it has indicated through its IR responses and final argument that it has considered provincial energy policy and it does not view its proposal to flatten rates to be in conflict with such policies. FBC submits it "continues to view provincial energy policy as an important and valid consideration in rate design, and has demonstrably supported initiatives that further the Province's energy objectives." In FBC's view, the issue to be considered is the extent to which the RCR continues to further those objectives and whether any resulting conservation can be reasonably achieved while balancing the other rate setting principles.[148]

Regarding whether conservation opportunities remain for residential customers, FBC submits that the weight given to forecasts of conservation persistence provided in 2011, such as those provided in the 2011 RIB Rate proceeding, should be balanced with the current state of electricity markets, where additional conservation may place upward pressure on rates. FBC further argues that while no party is in favour of wasteful consumption, "it is an oversimplification to suggest that all conservation (i.e. conservation for conservation sake) is desirable, or that a reduced level of consumption is necessarily preferable without some consideration of cost and other trade-offs such as comfort, safety or environmental impact."[149]

FBC's Long Run Marginal Cost

There was considerable interest from interveners relating to FBC's LRMC. One such issue is how the LRMC is established – should it include marginal transmission and distribution costs and, if so, how should those costs be included. A further issue is the LRMC's relationship to the Tier 2 rate – has it historically been used as a referent for the Tier 2 rate and should it be going forward.

FBC's LRMC of $96 per MWh (2015$) referenced in BCOAPO IR 42.1 is based on FBC's proposed preferred portfolio (A4) as described in the FBC 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management (DSM) Plan (2016 LTERP and DSM Plan) application. In the 2016 LTERP and DSM Plan decision published on June 28 2018, the BCUC did not accept FBC's proposed preferred portfolio in its entirety, specifically accepting up to the year 2024 and rejecting the years 2025 to the end of the planning horizon.[150]

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[147] FBC Reply Argument, p. 19.
[148] Ibid., p. 20.
[149] Ibid., p. 21.
[150] FBC 2016 Long-Term Electric Resource Plan (LTERP) and Demand-Side Management (DSM) Plan, Order G-117-18 and Decision, p. 19 and Directive 1.

FBC submits that it does not have an established methodology for combining the LRMC of reliable power, which is a system level number, with marginal transmission and distribution costs. FBC points to the following statement in the Deferred Capital Expenditure (DCE) Study filed as Appendix C to the 2016 LTERP and DSM Plan application, which stated: “T&D [Transmission and Distribution] costs will only be reduced if a significant amount of load reduction is attained in an area where the utility expansion plans can be altered.” FBC views the LRMC of power supply and the Deferred Capital Expenditures relating to infrastructure as two separate values expressed in different units and applying to separate parts of the system. FBC submits that they “cannot be readily combined and if summed together, would not be consistent with the established definition of ‘Long Run Marginal Cost.’”[151]

BCSEA-SCBC argues that “appropriate adjustments” to FBC’s LRMC produce an avoided cost reference figure that is not far below the RCR Tier 2 rate and that the use of DCE is well founded and based on an established methodology of the Régie de l’énergie of Quebec.[152] BCSEA-SCBC’s consultant, Phillip Raphals, calculated a preliminary estimate of FBC’s full LRMC using its data, standard methods and reasonable assumptions. BCSEA-SCBC argues that the resulting value, based on the A4 portfolio, is $129.71/MWh; only 16.9 percent less than the Tier 2 energy price of $156.17/MWh.[153] BCSEA-SCBC later submits that the appropriate referent for FBC’s Tier 2 energy price is $131.31/MWh. This figure is based on the previous analysis in Section 2.1.1 of BCSEA-SCBC’s evidence and reflects the LRMC identified by FBC in its 2016 LTERP and DSM Plan application, based on its A4 portfolio.[154]

BCSEA-SCBC also submits that although FBC criticizes Raphals’ specific adjustments, it has not provided its own estimate of an appropriate referent for the Tier 2 rate, instead, emphasizing that “LRMC has not played a role in the setting of the RCR in the past, and is not incorporated into any of the rate proposals in the Application.”[155]

FBC submits that the $131.13/MWh LRMC value derived by BCSEA-SCBC is not valid because it relies on adding an amount for a residential DCE avoided cost of $43.16/kW-yr (2017$) (or $23.03/MWh) to a power supply LRMC of $97.21 (2017$) and grossing up by 8.3 percent for line losses. FBC argues this amount is not appropriate for the following reasons:

- The DCE is calculated on a $ per kW-year basis and is intended to apply only to the system peak hour which is how it was used for DSM planning. Converting it into a $/MWh number is inappropriate. Setting this fact aside, and allowing the MW to MWh conversions, the value would only apply for the system as a whole, which is the same basis as for the energy supply LRMC, not for any particular customer class as BCSEA-SCBC has done. Even if this conversion were valid, which FBC says it is not, the DCE would need to be adjusted for the system-wide load factor, not the residential-specific load factor, which would result in a lower T&D amount per kWh.

[151] Exhibit B-23, BCOAPO IR 76.1.
[152] BCSEA-SCBC Final Argument, p. 18.
[153] Exhibit C2-6, p. 11.
[154] Exhibit C2-10, BCUC IR 1.7.
[155] BCSEA-SCBC Final Argument, p. 18.

- Since the DCE value was calculated prior to the transmission plans included in the LTERP and was not updated to reflect the transmission projects included in the LTERP, the value would need to be updated accordingly and may well end up lower based on the current LTERP.
- The DCE is a non-time differentiated value. The DCE is a demand-based cost, not an energy cost. Signaling the cost of capacity via a non-time-differentiated energy rate (the RCR Tier 2 rate) is not appropriate.
- Use of the DCE does not account for locational attributes. FBC network planning is based on the actual load growth trajectory for specific lines and substation equipment. For example, there may be cases where a large new customer is added to the system or there is an area of concentrated growth in one particular service region (e.g. Kelowna) that results in additional infrastructure requirements based on locational conditions, but not necessarily the need for additional power supply resources. The need for planned T&D infrastructure projects within the planning horizon for FBC is driven by ongoing peak load growth in the Kelowna area.
- Including a T&D component is inconsistent with FBC's definition of LRMC and could introduce the risk of redefining the scope of the LRMC.[156]

BCSEA-SCBC states "[w]hile the LRMC itself may be somewhat uncertain," in its view, "there is no uncertainty that achieving incremental conservation and efficiency savings is valuable to FBC and its customers."[157]

In its reply argument, FBC notes that BCSEA-SCBC has not rebutted its criticisms of the BCSEA-SCBC calculations, choosing instead only to reiterate that BCSEA-SCBC believes its methodology is well founded.[158] FBC also notes that "while BCSEA-SCBC and BCOAPO both accept the economic theory that supports the use of LRMC as a referent for rates that lead to economically efficient consumption decisions on the part of customers, the conclusions of BCSEA-SCBC lead it to suggest a modified form of the RCR, while the BCOAPO, citing a much lower LRMC, conclude that the flat-rate proposal of FBC ought to be accepted."[159]

AMCS/RDOS submits that a properly constructed RIB rate would be set with "… the Block 2 rate equal to the marginal cost of new electricity supply." [160] However, with the current LRMC below the current flat rate and both the Tier 1 and Tier 2 rates of the RCR, it submits that it is not practical to utilize the LRMC to set rates. AMCS/RDOS therefore advocates for a flat residential rate, and states the following:

> Since the Flat Rate is above the marginal cost of supply, the former becomes the right price for encouraging energy efficient behaviour. Under a Flat Rate system, all customers pay the same rate so all customers will be encouraged to be efficient. The Flat Rate has been shown in past rate proceedings to meet all of the other design criteria.[161]

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[156] FBC Final Argument, pp. 23-24.
[157] BCSEA-SCBC Final Argument, pp. 14-15.
[158] FBC Reply Argument, p. 9.
[159] Ibid., p. 4.
[160] AMCS/RDOS, Exhibit C3-7, p. 31.
[161] AMCS/RDOS Final Argument, pp. 30–31.

FBC notes that, as a LRMC measure, this value will not go up year to year because it already accounts for expected increases in costs for power and T&D over time. Further, given that the rates in the Application are based on 2017 revenue requirements, they will first need to be updated to 2019 values, and going forward will likely increase as future revenue requirements necessitate additional rate increases. If the Tier 2 rate were tied to this LRMC, it is likely that any rate increases would affect only the Tier 1 and/or Customer Charge rates since it would not be appropriate to increase the Tier 2 rate in this circumstance. The natural effect of this proposal is the erosion of the rate differential, which over time would lead to a flat rate, assuming no further increases to the LRMC.[162]

Panel Determination

For the reasons set out below, the Panel approves FBC's Application to switch to a flat rate for residential customers and to phase in the flat rate over a 5-year period, consistent with the previously approved phase-in of the increased customer charge of $18.70 per month.

In the following sub-sections we consider the evidence regarding a switch to a flat rate – in particular, in the following areas:

- Cost causation;
- Alternative rate designs;
- LRMC and its relation to both the tier 2 rate and the flat rate;
- BC's energy policy objectives;
- The Minister's letter to FBC;
- Bill impacts and the phase-in period; and
- Access to natural gas for heat and hot water.

Cost Causation

FBC argues that the RCR is not driven by cost causation whereas the flat rate is and therefore, in this regard, the flat rate is more aligned with the Bonbright principles. The multi-tiered pricing inherent in the RCR is not reflective of cost causation principles. Although using the LRMC for the Tier 2 rate is arguably using an expected future cost, FBC's Tier 2 rate has never been set with reference to FBC's LRMC, so even this causation basis has been lacking.

The Panel agrees that all else equal, this is the case. However, we note that to the extent that the flat rate also recovers some fixed costs that are not recovered in the Customer Charge – in this case over 45 percent of fixed costs, the flat rate is not purely driven by cost causation. Nonetheless, this is also the case with the RCR. Therefore, we find the flat rate more closely aligns with cost causation principles than the RCR.

Alternative Rate Designs Examined by FBC

FBC has considered a number of alternative rate designs, including:

- a standalone rate for customers without access to natural gas service;
- changing the RCR in a number of ways including:

[162] FBC Final Argument, p. 23.

- changing the Tier 2 threshold;
    - decreasing the difference between Tier 1 and Tier 2 rates;
    - a seasonal threshold;
- a declining block rate;
- optional TOU;
- a return to a flat rate;
- changes to the Customer Charge including:
    - increase to equal RS 03;
    - increase toward COSA unit cost;
    - reduce or eliminate.[163]

We are satisfied with the alternative designs that have been considered by FBC, and with the level of analysis of each alternative. There is no persuasive evidence that any of these options better meet the objectives that FBC has laid out – i.e. cost causation, customer ease of understanding, additional conservation, or reduced bill impact on high consuming customers – nor are they better aligned with the Provincial government's objectives. Further, no interveners, with the exception of BCSEA-SCBC, argue otherwise. We will address BCSEA-SCBC's arguments below.

Tier 2, LRMC and the Flat Rate

There was considerable discussion regarding FBC's LRMC, although the approval to return to a flat rate renders the issue of the LRMC largely moot. However, arguments were made concerning the relationship between the marginal cost of electricity and the propensity of customers to conserve. We comment on this issue here.

A key rationale for inclining block rates is to incent more economically efficient behaviour where the marginal cost of supply is above the flat rate. Theoretically, an inclining block rate provides an opportunity to set the second tier rate at the marginal cost of supply, thereby providing the incentive for customers to reduce energy consumption which may enable the utility to avoid the cost to generate additional supply. BCSEA-SCBC submits that if the RCR remains in place it will continue to provide conservation and efficiency savings and "[t]o lose these valuable savings by terminating the RCR would indeed be of significant concern and would be contrary to the legislated energy objectives and the interests of FBC's residential customers as a whole."[164]

Acknowledging that economic theory is used to support the use of LRMC as a referent for rates that lead to economically efficient consumption decisions on the part of customers, the BCUC has previously commented that the "appropriate referent for the tier 2 rate is the LRMC."[165] In addition, we note that historically the LRMC has been above the average embedded cost of acquiring and delivering energy. If this is no longer the case, setting the second tier at the LRMC would, all else equal, result in a declining block rate. However, as FBC has pointed out, the LRMC has never actually been used to set its Tier 2 rate.[166]

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[163] Exhibit B-1, pp. 59–60.
[164] BCSEA-SCBC Final Argument, p. 16.
[165] FBC 2011 RIB Rate Decision, p. 40.
[166] FBC Final Argument, p. 22.

A further issue is how the LRMC should be calculated. Is it the cost of energy generation and acquisition, or should it also reflect the costs of transmission and distribution required to deliver that energy to the customer, and, if so, how are those costs calculated? Further complicating the calculation, FBC's LRMC of energy alone was approved, in the 2016 LTERP and DSM Plan decision, only up to 2024.

Given these issues, it is not surprising there is significant disagreement among parties in this proceeding on the appropriate LRMC. In summary, BCSEA-SCBC argues for a LRMC that includes the costs required to deliver new supply to a residential customer – which it calculates as $131/MWh.[167] AMCS/RDOS submits that $99/MWh is the current LRMC, while BCOAPO suggests that $95.15/MWh is the appropriate amount after accounting for losses and adjusting to $2017.[168] The highest LRMC estimate – BCSEA-SCBC's $131.13/MWh – is lower than the current Tier 2 rate, but higher than the proposed flat rate in five years.

The Panel accepts FBC's argument that BCSEA-SCBC's calculation likely overestimates the actual cost of Transmission and Distribution, although there is insufficient evidence to determine by how much. Accordingly, the appropriate LRMC likely lies in the range between something greater than $95/MWh and something less than $131.13/MWh. Given our approval of FBC's proposed flat rate, there is no need to determine a more accurate measure of LRMC at this time.

We are also persuaded by FBC's argument that the LRMC, whatever its actual value, will not increase year by year as it already accounts for expected increases in costs, whereas the actual rate paid by customers will, in all likelihood, increase over time with inflation and other drivers of cost increases. If the RCR was continued, with the Tier 2 rate set at the LRMC (for example $131.13 in BCSEA-SCBC's scenario), all cost increases must be applied to the Tier 1 rate, with the eventual result being a flattening of the RCR, although it is not possible to determine when that would occur. Therefore, if the RCR were to use the LRMC for the Tier 2 price, it would eventually result in a rate that is, or is very nearly, flat.

The flat rate is not set in relation to an LRMC; instead, it directly reflects the cost of service. However, we note that the proposed flat rate of $117/MWh in $2017 is within the likely range of an LRMC, and, as such it may provide an appropriate price signal to customers – one that is as effective as the existing Tier 2 rate has been, given that it is also below the LRMC.

BC's Energy Policy Objectives

BCSEA-SCBC and FBC take starkly different positions with respect to the RCR and BC energy policy:

- FBC argues that energy conservation is no longer the primary driver "to the same degree today, particularly in light of the Province's increased focus on electrification."[169]
- BCSEA-SCBC argues "[t]he proposal to phase out and eliminate the RCR is contrary to the BC energy objectives."[170] In its view, "there has been no diminishment of the policy objective to reduce electricity consumption through conservation and efficiency measures. Nor should there be." BCSEA-SCBC further

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[167] Exhibit C2-10, BCUC IR 1.7.
[168] BCOAPO Final Argument, p. 47.
[169] FBC Final Argument, p. 17.
[170] BCSEA-SCBC Final Argument, p. 10.

submits "[l]ow carbon electrification is a crucial energy objective," which it strongly supports, and "[w]asting clean renewable electricity by failing to implement cost-effective conservation and efficiency measures is a hindrance to low carbon electrification."[171]

The Panel does not fully endorse either argument. Energy conservation remains an objective in the CEA and there is nothing to indicate it has been diminished. We discuss this further below. However, to characterize the issues that give rise to FBC's application to flatten the RCR, as wasting electricity by failing to implement cost-effective conservation, is not supported by evidence. The high electricity costs faced by some FBC customers provide incentive to reduce electricity usage. The evidence provided by AMCS/RDOS supports this.[172] Further, the proposed flat rate is, as we have previously found, sufficiently close to the LRMC and as such, will provide an economically efficient incentive for continued conservation efforts.

BCSEA-SCBC has commented that "there has been no diminishment of the policy objective to reduce electricity consumption through conservation and efficiency measures…." The Panel also notes that the policy to which BCSEA-SCBC appears to be referring, as laid out in the CEA and as applicable to FBC, is:

> (b) to take demand-side measures and to conserve energy…[173]

We are of the view that as the RCR is replaced by a flat rate, FBC should continue its demand-side measures, and we note that there is no evidence to indicate that FBC will do otherwise.

Further, the policy requires that British Columbians conserve "energy" – and in this context there is a significant difference between "energy" and "electricity consumption." Increasing the use of electricity while, as a consequence, reducing the use of another form of energy is entirely consistent with objective (b).

The objective outlined above to conserve energy can be considered along with the following CEA objective:

> (h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia…;[174]

In this regard, we note FBC's comment that a transition from the existing RCR to a flat rate structure may promote the use of electricity for various residential uses – for example home electric vehicle charging – thereby meeting objective (h).

In this regard, we note the following of BC's energy objectives as outlined in section 2 of the CEA:

> (g) to reduce BC greenhouse gas emissions
>
> i. by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,
>
> ii. by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

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[171] ibid., pp. 10–11.
[172] Exhibit C3-7, Appendix B.
[173] *Clean Energy Act*, SBC 2010, c 22.
[174] Ibid.

iii. by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

iv. by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

v. by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;[175]

The provincial energy objectives are clear that encouraging "the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia" is desirable. We also note the BC Government's recently announced Climate Action Plan,[176] with updated BC emissions reduction targets. Using 2007 as the baseline, we are now committed to reductions of:

- 40 percent by 2030
- 60 percent by 2040
- 80 percent by 2050[177]

Further, in areas where there is a choice of alternatives, a higher price for electricity than the price of alternatives that produce more GHG emissions may be a disincentive to use electricity. From this we conclude that the RCR could potentially hinder the province's energy objectives as they apply to FBC.

We therefore find FBC's proposed rate changes are not in conflict with BC's energy objectives.

Minister's Letter to FBC

In approving this rate design change, we place weight on the Minister's letter to FBC arising from the BCUC RIB Rate Report, which encourages FBC to:

1. 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.
2. 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.[178]

We note that efficient electrification remains a key element of the Provincial government's climate action plan. In the Panel's view, the flat rate can contribute to efficient electrification, as explained above.

Bill Impacts and the Phase-in Period

FBC has considered how the proposed rate structure impacts customer bills and has presented a number of rate impact scenarios. In general terms, an inclining block rate provides a relatively small saving to a large number of ratepayers. These savings are "funded" by a relatively large increase to a small number of ratepayers with higher consumption (as with most rate designs, changing a particular rate structure is revenue neutral to FBC). In moving back to the flat rate, the reverse will occur and a relatively large segment of the residential rate class will see a relatively small bill increase.

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[175] *Clean Energy Act*, SBC 2010, c 22.
[176] The Province of British Columbia, Climate Leadership Plan (August 2016)
[177] Ibid., p. 12.
[178] Exhibit B-1, Appendix J.

However, for some customers the combined move to the flat rate and increase in the Customer Charge could lead to a significant bill impact for some customers if these changes are implemented immediately. Further, the aforementioned bill impacts do not take into account impacts resulting from potential future revenue requirement rate increases. Notwithstanding any revenue requirement-related rate increases, FBC proposes to phase in the rate changes resulting from the move to the flat rate and increase in the Customer Charge over five years and has presented comparative analysis of different phase-in periods. Although BCSEA-SCBC states that for some customers phasing out and terminating the RCR "would be a hardship,"[179] the Panel notes that BCOAPO, which represents, among others, low income customers, supports FBC's proposal.[180] We therefore find that FBC's proposed phase-in period of five years appropriately smooths the rate impact related to the move to the flat rate and increased Customer Charge for those customers who are most impacted.

Access to Natural Gas for Heat and Hot Water

We acknowledge that the RCR may incent a reduction in consumption, particularly in the range where consumption is elastic – e.g. where natural gas is available to provide heat and hot water. However, where electricity is required to provide heat and hot water because it is the only viable alternative, the RCR may be perceived as an undue burden on some users. We also acknowledge the position of those interveners that live in areas with no access to natural gas and therefore heat their homes with electricity. Some of these customers have seen significant bill increases and this is one reason that FBC seeks an alternative residential rate structure.

BCSEA-SCBC states that "[w]asting clean renewable electricity by failing to implement cost-effective conservation and efficiency measures is a hindrance to low carbon electrification." [181] However, there is no evidence before us that electrical energy is being "wasted." Given the relatively high price of electricity paid by some users, there is significant incentive to reduce consumption. AMCS/RDOS provides testimony of a number of residential customers who have responded to high electricity bills by reducing usage.[182]

The Panel finds FBC's proposal to replace the RCR with a flat rate and an increased customer charge to be just, reasonable and not unduly discriminatory and it will reduce the significant bill impact that some customers have faced.

4.2.2 Optional TOU Rates

FBC has applied to revise and re-open the optional residential TOU rate to all residential customers and revise all other non-residential TOU rates. It is FBC's belief that customer choice is enhanced by offering TOU rates and customer satisfaction may be improved by having an optional rate for those customers desiring to enroll in a conservation rate.

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[179] BCSEA-SCBC Final Argument, p. 19.
[180] BCOAPO Final Argument, pp. 50–54.
[181] BCSEA-SCBC Final Argument, p. 11.
[182] Exhibit C3-7, Appendix C.

4.2.2.1 Background

FBC states that TOU rates are designed to provide an incentive for customers to shift consumption patterns in a way that allows a utility to either reduce costs or generate additional revenue. Accordingly, TOU rates are used to send customers price signals to reduce consumption during periods where the system has peak loads, thus decreasing or potentially deferring costly transmission or generation projects that may be needed to address capacity requirements. Any benefit derived from such changes in consumption will accrue to all customers. At present, FBC offers TOU rates to all retail classes, although the rate for new residential customers was closed in 2012 and only customers who were enrolled at that time remain. FBC states that as part of the Application process it has completed a comprehensive review of TOU rates. This has been done to allow for its proposal to reconfigure and reprice its TOU rates for all rate classes and reintroduce the TOU rate for the residential class on an optional basis.[183]

FBC states that in 2016 the number of customers taking service under RS 2A (Residential TOU rate) totalled 175, under RS 22A (Commercial Service- Secondary TOU) 20 customers and one customer was taking service under RS 32 (Large Commercial-Primary TOU). No customers in any of the other rate classes have taken service under the available TOU rates.

All current TOU customers have “on-peak” and “off-peak” pricing structures. However, TOU time periods and rates vary by customer class and whether they are secondary voltage or primary or transmission voltage. Those served at secondary voltage have two pricing seasons (summer and other months), while those at primary and transmission voltage have three pricing seasons (winter, summer and shoulder), with the rate a customer pays dependent on the customer rate class and the time period in which electricity is consumed. The current rates and periods were set based on analysis of the 1997 COSA and load profile that existed at the time. Current TOU pricing are shown in Table 19 below: [184]

Table 19: Current TOU Pricing

Rate Class	Winter		Summer		Shoulder	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Residential	$0.19710	$0.06383	$0.19710	$0.06383	$0.19710	$0.06383
Commercial Service - Secondary	$0.15122	$0.04900	$0.15122	$0.04900	$0.15122	$0.04900
Commercial Service - Primary	$0.21839	$0.05470	$0.21015	$0.04542	$0.06015	$0.03778
Large Commercial Primary	$0.22675	$0.04623	$0.21769	$0.03598	$0.05222	$0.02754
Large Commercial Transmission	$0.17574	$0.04978	$0.23439	$0.03874	$0.05623	$0.02964
Wholesale Primary	$0.24426	$0.04979	$0.23452	$0.03876	$0.05626	$0.02961

Rate Class	Winter		Summer		Shoulder	
Wholesale Transmission	$0.16713	$0.04734	$0.22295	$0.03683	$0.05351	$0.02818
Irrigation	$0.19235	$0.04823	$0.18510	$0.03999	$0.05297	$0.03323

[183] Exhibit B-1-4, Errata, p. 108; Exhibit B-8, BCUC IR 75.2.

[184] Exhibit B-1, Tables 8-1 – 8-3, pp. 109–110.

FBC states that the current rates and time periods for applicable energy charges were first set as part of its 1997 RDA. Since that time rates have been escalated by revenue-related increases but there has been no change in the underlying assumptions. As noted, there has been limited customer uptake since 1997 and since that time, FBC has not conducted a formal review of the program examining it against the original rationale used to set existing TOU time periods or pricing. FBC reports that it has not surveyed its customers to determine whether their experience with the program has met their expectations, and their original motivation for joining is unknown. Thus, the reasons for lack of uptake in the program also remain unknown, although FBC speculates that customers "have a preference for a simple, stable rate structure". Adding to this, FBC further reports that all of its TOU customers signed up for the program at a time when hourly load data was not collected and as a consequence, any analysis of consumption patterns would be complicated by factors such as rate changes, appliance changes or other customer changes since inception. Thus, FBC does not consider there to be sufficient data to determine whether there were changes in consumption behaviour. FBC does report that in response to rates rising, there has been greater interest in the availability of TOU rates. However, it speculates this interest appears to be more related to an interest in bill mitigation rather than as a conservation measure.[185]

4.2.2.2 Outline of Revised TOU Proposal

With the current Application, FBC states it has updated the assumptions and allocations associated with the rates and seeks approval to reconfigure and update TOU rates for all rate classes and reintroduce a TOU rate on an optional basis for residential customers. In updating its assumptions, FBC notes there is a need for data apart from typical COSA-based cost allocations due to their not being differentiated on the basis of time. To deal with this, FBC has relied on data from its Advanced Metering Infrastructure (AMI) which provides accurate hourly customer consumption information allowing appropriate TOU time periods and the optional billing option to be derived. This information allows for TOU time periods to be time-based to the extent possible for the rate to achieve its objective of changing behaviour, resulting in the desired financial benefit.[186]

FBC states that two steps are required to evaluate how well the current TOU rates are reflective of the current load profile, its related costs and in determining revisions to current rates that are required. The first step in the process was to examine appropriate time periods upon which to base rates and following this, to examine cost differences by the time periods that have been identified.

TOU Rate Periods

FBC states that the goal in developing rate periods is to identify those where there is consistently high-use levels and set periods that are easy to understand and will not lead to a shift in the utility's peak period. The analysis conducted and experience with other utilities indicated that rather than relying only on the current on-peak and off-peak periods it would be better to add a third "mid-peak" period during certain months. FBC explains that winter and summer months both have higher usage and costs in peak months while the shoulder months have lower costs. The same types of variances occur within each day where loads and costs are highest in the early evening or in the morning. The results of FBC's analysis yielded results for each period as outlined in Table 20.[187]

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[185] Exhibit B-1, p. 110.; Exhibit B-8, BCUC IR 76.4.2, BCUC IR 76.7.
[186] Exhibit B-1, p. 108.
[187] Exhibit B-1, p. 112.

Table 20: Proposed TOU Periods

	Winter	Shoulder	Summer
On-Peak	7 am to 12 pm 4 pm to 9 pm weekdays		12 pm to 9 pm weekdays
Mid-Peak	12 pm to 4 pm weekdays	7 am to 9 pm weekdays	7 am to 12 pm weekdays
Off-Peak	9 pm to 7 am weekdays and all day weekends and Holidays	9 pm to 7 am weekdays and all day weekends and Holidays	9 pm to 7 am weekdays and all day weekends and Holidays

Worthy of note is that weekend rates have no changes as they are treated entirely as off-peak because loads are low compared to weekday loads.

TOU Pricing

The next step in the process is to look at cost differentials that exist between the TOU periods. FBC explains that, for the distribution system, numbers of customers and the non-coincidental peak of each is used in the planning of facilities and is in turn reflected in the COSA allocations for distribution costs. Transmission and distribution system costs, while driven by peak demand, are nonetheless fixed and unaffected by the timing of consumption and therefore, are not a factor when deriving TOU rate differentials. Power supply costs do differ by time period and thus are a basis for analysis. FBC further explains that for this analysis the 2017 power supply costs were split into categories covering capacity-related costs, energy purchases and base load costs. Capacity costs are considered variable and include capacity charges related to purchased power and are applied only to the on-peak period. Variable energy costs included energy charges from BC Hydro power purchases or from the market and apply to both the on-peak and the mid-peak period. These charges are incurred for periods where loads are higher and FBC's generating and contractual resources are exceeded. They best match the mid-peak period where loads exceed the system base load and the load during the potential on-peak hours. All other power costs are categorized as base costs and applied to all TOU periods. The next step is to divide the capacity-related loads by the on-peak loads which yields a unit cost of 10.57 cents per KWh and reflects the necessary adder for on-peak rates relative to mid-peak rates. Similarly, variable energy costs are divided by the mid-peak period energy resulting in a unit cost of 2.59 cents per KWh reflecting the differential in rates between mid-peak and off-peak periods. FBC notes that these differentials form the basis for the TOU rates and are the same for all classes. However, actual rates that apply to each customer class are different because the amount of load that falls within each period varies. As a final step, an elasticity factor was applied to each time-period to account for assumed usage impacts associated with TOU rates.

FBC states that TOU pricing for the described periods is built on a base energy price for each rate class and adjusted further based on the time-delineated cost differentials. Based on the TOU time-periods, a matrix was developed splitting the load by time period in terms of the percentage of load for each class. Finally, based on the breakdown by time period and the elasticity assumption and time differentials, the pricing as outlined in Table 21 was developed.[188]

Table 21: Revised TOU Rates

Rate Class	On-Peak Rate	Mid-Peak Rate	Off-Peak Rate
Residential	$0.22435	$0.11869	$0.09280
Small Commercial	$0.20675	$0.10109	$0.07520
Commercial	$0.19795	$0.09229	$0.06640
Large Commercial Primary	$0.19285	$0.08719	$0.06130
Large Commercial Transmission	$0.18395	$0.07829	$0.05240
Wholesale Primary	$0.19995	$0.09429	$0.06840
Wholesale Transmission	$0.19185	$0.08619	$0.06030
Irrigation	$0.17869	$0.07303	$0.04714

Revenue Recovery

The proposed TOU rates have been set so total forecast revenues collected are revenue neutral with the proposed non-TOU rates and the revenue requirement for each class. This is done under the assumption the entire class is participating as partial participation may lead to an over-collection or under-collection as compared to the default rate. [189] FBC explains that over time the adoption of TOU rates will grow and as this occurs, TOU loads and revenues will be included in forecasts and updated annually. As a result, the effects of changing levels of adoption will be reflected in revenue surpluses or deficiencies in the revenue requirements process. The current handling of these is through a flow-through deferral account which is either refunded to or recovered from customers in subsequent periods. Any loss of revenue would be recovered from all customers through the flow-through deferral account or RRA if TOU rate revenue variances had been captured in the revenue forecast. This is no different from the treatment of existing TOU rates for all other customer classes, or for the previous set of residential TOU rates that were offered by FBC.[190]

TOU Rate Program Rationale and Implementation Plans

FBC proposes to make TOU rates optional and available to residential customers and other rate classes with the stipulation that the revised program would be subject to review after a three-year period. FBC's rationale for offering TOU on an optional basis as opposed to mandatory is that customer interests are best served by a default rate based on costs with a conservation rate that is optional and available to those customers "whose particular circumstances allow an opportunity for personal savings and with the potential to deliver benefits to customer[s] in general." It further states that mandatory rates have the potential to "create an inequity among customers that cannot readily be justified by any constraints faced by the Company in meeting its load obligations."[191] FBC further proposes to track its results with the new offering and undertake a full review of the program after a three-year period which would be the basis of its recommendation to the BCUC with respect to whether the rate should be continued. Part of the analysis informing this recommendation would be an

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[188] Exhibit B-1, pp. 112–115.
[189] Exhibit B-8, BCUC IR 79.1.3.
[190] Exhibit B-8, BCUC IR 75.2; Exhibit B-11, BCOAPO IR 59.3.
[191] Exhibit B-8, BCUC IR 93.1.

assessment of the changes in customer behaviour prompted by TOU rates which would serve to inform any future adjustments to make the rate more effective in load shifting and the creation of customer benefit. FBC considers such an approach will provide valuable insight into customer enrolment and response at low risk.[192]

With respect to savings resulting from TOU rates, FBC explains that some short-term capacity savings under the BC Hydro Power Purchase Agreement (PPA) and/or Waneta Expansion may occur as a result of shifting usage from on-peak and mid-peak hours. However, it cannot estimate these as it would be dependent on load and market prices at the time of the surplus and it lacks knowledge as to participation rates. FBC states that real savings potential could be realized if sufficient load could be shifted away from peak with certainty resulting in a reduction of power purchases or in the ability to defer investment in new generation requirements that might be needed to meet growing demand. That said, it is acknowledged that the addition of new generation resources is not anticipated over the planning horizon.[193]

FBC estimates that approximately 19 percent of customers (22,421) without making any changes to their consumption patterns would be better off financially with TOU rates. Assuming that no other residential customers opted for the TOU rate, this converts to an approximate $9.4 million in lost revenues out of a total of $185 million. This would result in an additional rate impact of $0.0007 KWh for residential class customers or $0.003 KWh if applied to all customer classes.[194]

FBC states that a complete implementation and communication plan will not be completed until following BCUC approval of the TOU rate. However, broad initiatives to support customers are expected to include the following:

- Specific mention of the TOU option as part of all communication related to approvals related to the Application;
- Increased presence on the FortisBC website;
- Communication through FBC social media channels;
- Inclusion in outgoing electronic billing communication; and
- Increased awareness by FBC customer service representatives.

These initiatives have relatively minor cost but could be augmented by community information sessions and individual billing analysis. FBC acknowledges it has yet to evaluate these options.[195]

FBC states it is not reasonable to estimate participation rates and the resulting power savings prior to implementation of the program. It has made what it believes to be reasonable assumptions regarding the shift of customer load in response to the price signals in rates and the potential for cost savings to be realized, but actual customer behaviour will not be known without experience. This is why FBC has proposed a three-year evaluation period followed by a recommendation to the BCUC regarding the program. FBC states that part of the analysis informing this recommendation would be an assessment of changes in consumer behaviour

[192] Exhibit B-1, p. 115; FBC Final Argument, pp. 29–30.
[193] Exhibit B-11, BCOAPO IR 56.7; B-21, BCUC IR 134.5.
[194] Exhibit B-12, BCSEA-SCBC IR 34.3; Exhibit B-24, BCSEA-SCBC IR 18.1.
[195] Exhibit B-1, pp. 115–116.

prompted by TOU rates. FBC further states that in addition to this final report, it would be amenable to an annual reporting regimen.[196]

As an aid to customers interested in participating in TOU rates, FBC will have a web portal where customers have access to TOU information. Noting that the customers' ability to manage consumption is enhanced by information related to their consumption habits, this system will provide this information as well as the information required to understand the benefit of shifting consumption. FBC also indicates that it intends to provide its customers with the ability to connect in-home displays to provide web-based access to TOU period consumption information. Such display equipment could be purchased from a third party vendor but FBC acknowledges that in-home displays with the capability to display demand readings such as those in non-residential rate schedules may prove difficult to source. FBC has tested in-home displays from a BC-based company but to-date has not arranged for a vendor to supply.[197]

With respect to the timing for implementation, FBC had originally planned for a date in June, 2019, five months after what it expected to be the implementation of other rate schedules. The reason for the delay is because the addition of the mid-peak time period requires additional AMI and billing-related system work. FBC states that because the proposed TOU rates have a different rate structure a new rate structure must be designed, built and tested in the billing system and any other integrated applications. FBC estimates the cost of this to be approximately $166 thousand (+/- 50 percent) with 50 percent of the required work completed as part of normal business activities. But in the event significant additional resources were required, it would advise the BCUC and request a determination on the recovery of such costs.[198]

It is FBC's belief that offering TOU rates enhances customer choice and, in addition, customer satisfaction may also be improved by having an optional rate for those customers desiring to enroll in a conservation rate. FBC argues that the intention of TOU rates is to shift the time of consumption, allowing the utility to generate incremental revenue or reduce costs, with the benefit accruing to all customers. It further states, "unless the changes in behaviour caused by the rate result in the desired financial benefit, the rate will not have achieved its benefit." FBC is clear that the goal of TOU rates is not to shift loads but rather, to reduce the utility's overall peak demand which in turn drives the need for power costs and many of FBC's facilities. FBC states the real savings potential for TOU rates as follows:

> If sufficient consumption were to be shifted away from the peak with certainty, it may, over the long term, result in a reduction of power purchase expense and at some point, result in deferred investment into new generation requirements that would otherwise be required to meet growing peak demand.[199]

[196] Exhibit B-8, BCUC IR 94.1; FBC Final Argument, p. 29.
[197] Exhibit B-8, BCUC IR 90.3, 90.3.3, 90.3.4; Exhibit B-21, BCUC IR 135.3, 135.4.2.
[198] Exhibit B-1, p. 115; Exhibit B-8, BCUC IR 90.2; Exhibit B-8-1.
[199] FBC Final Argument, p. 28.

4.2.2.3 Positions of the Parties

AMCS/RDOS

AMCS/RDOS supports FBC's proposal to reopen its TOU rates to customers as long as it is on a voluntary basis. It does not support such a program if it is on a mandatory basis because customers using electricity for space and water heating would be unfairly penalized and all customers cannot shift a significant portion of their electricity consumption from peak to off-peak hours. Moreover, if the majority of customer consumption occurs during peak hours, such customers would experience increased rates regardless of whether they had taken action to shift some consumption, which would contribute to a reduction of the cost of generating and distributing electricity.[200]

AMCS/RDOS notes that those who elect to go on TOU rates will be paying a rate that is below the default rate, but accepts this as reasonable as long as the rate differential does not exceed the amount of cost savings resulting from the load shifting. If, on the other hand, the rate differential exceeds the resulting savings, a cross subsidy would result. The fact that the estimated revenue deficiency would range from a high of $9,379,657 (as compared to the current residential rate) to a low of $729,433 (as compared to the proposed Year 5 flat rate) indicates that cross subsidization could occur especially during the transition period. AMCS/RDOS states its proposal to move immediately to flat rates "would go a long way to addressing the problem." [201]

The CEC

The CEC considers optional TOU rates to be an opportunity for the utility to manage its costs and for ratepayers to reduce their bills. The CEC supports the proposed three year trial period as it will give customers adequate time to become aware of and utilize the program and make a decision as to whether it fits their immediate circumstances. The CEC recommends the proposal be approved as applied for.[202]

KSCA

KSCA seems to generally be in support of the idea of moving forward with some form of TOU rates on a pilot basis if not actually supporting the TOU proposal which has been made by FBC. The most significant problem it seems to have with the current proposal is the impact on the residential class of the time periods proposed by FBC with respect to on-peak, mid-peak and off-peak rates. While agreeing that an overall on-peak load exists in winter between 8:00 am and noon and again between 5:00 pm and 9:00 pm, KSCA's position is that residential loads as a percentage of peak during these periods are much lower than the average. Because of this, in its view, the residential class is subsidizing the other classes and these other classes should be charged the on-peak costs, not the residential class. In addition, noting that the residential class has a consistent on-peak presence between the hours of 5:00 pm and 9:00 pm, KSCA suggests that FBC send a consistent price signal about on-peak consumption and set a consistent on-peak price for the entire year.[203]

[200] AMCS/RDOS Final Argument, pp. 36–37.
[201] Ibid., pp. 37–38.
[202] CEC Final Argument, pp. 43–44.
[203] KSCA Final Argument, pp. 21–23.

The underlying concern raised by KSCA seems to be that it is difficult for certain ratepayers to benefit when peak pricing is set between 5:00 pm and 9:00 pm and asks the Panel to:

> …carefully consider, when setting any TOU rates, the fact that large numbers of residential customers cannot avoid using electricity during On-Peak hours, and that therefore they should not be financially penalized for accessing electricity when they need to. And to consider that some electricity use, because of the nature of how society organizes itself, cannot be shifted, and therefore, the ability of certain customers to shift their discretionary use of electricity might actually be quite minimal.[204]

BCOAPO

Due to the concerns and deficiencies it has raised in its submissions within its final argument, BCOAPO submits that the BCUC should reject the revised TOU rates as proposed by FBC. BCOAPO also believes that if FBC wishes to pursue TOU rates in the future it should be required to address the issues raised by them. The primary concerns raised by BCOAPO by topic are as follows:

Purpose of TOU Rates

BCOAPO considers it important for goals and objectives associated with the implementation of TOU to be clearly established as this will assist both in determining an appropriate pricing structure and assessing the success of the program after three years. In BCOAPO's view, the objective for implementing TOU rates is to provide a rate benefit to all other customers and "should be the primary purpose underlying the design of TOU rates and the primary objective by which to measure their success."[205]

TOU Period Selection

While accepting there is a relationship between loads and costs, BCOAPO argues that it is not perfect and argues that FBC's proposed TOU periods should be subject to cost analysis. In addition, BCOAPO questions whether there should be a third month (June) added to FBC's proposal for July and August as the summer months, and suggests this be addressed as part of the review if the revised TOU rates are approved.[206]

Determination of Proposed Pricing Differentials

With respect to on-peak capacity differentials, it is not clear to BCOAPO why the capacity costs associated with the Kootenay River are included among these costs, noting that purchases under the Brilliant PPA are excluded as they are fixed cost resources and therefore fully utilized by FBC. Based on FBC's stated approach of focusing on costs that could/would change over the short term due to a load change, BCOAPO argues that only RS 3808 capacity costs and the Waneta Expansion should be considered when determining price differentials. FBC's own generation should be considered baseload in a manner consistent with the Brilliant PPA. Because of this, BCOAPO's overall assessment is that FBC's determination of on-peak capacity cost differential is flawed and inconsistent.[207]

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[204] KSCA Final Argument, p. 23.
[205] BCOAPO Final Argument, pp. 75–76.
[206] Ibid., pp. 76–77.
[207] Ibid., pp. 78–79.

Energy Cost Differentials

BCOAPO takes issue with FBC's justification of assigning BC Hydro and market purchases as incremental costs applied to on-peak and mid-peak periods because the energy provided by Brilliant and its own plants exceeds required off-period energy requirements. To BCOAPO, this suggests "that purchases from BC Hydro and the market are only used to meet load requirements in the on-peak and mid-peak periods." BCOAPO submits there is no difference in the incremental cost of energy between the on- or mid-peak and the off-peak period and therefore, no basis for the energy cost differential. This assertion is based on FBC's confirmation that when owned plants and Brilliant power is fully dispatched, FBC would need to meet additional off-peak use through either BC Hydro or market purchases, and shifting energy from mid-peak to off-peak hours would not change FBC's composition of resources. BCOAPO further submits that this evidence supports the view that there is no basis for distinguishing between mid-peak and off-peak periods and recommends that if approved, TOU rates should include only an on-peak and off-peak period where mid-peak hours are covered by the latter. [208]

BCOAPO also asserts that there are issues with the manner in which FBC has determined the price differential, noting that the differential "is to be based on the cost of energy provided by purchases from BC Hydro and the market, the determination of the unit cost differential is derived by dividing these costs by the total energy in the on-peak and mid-peak periods which exceeds the energy provided by these two resources." Therefore, the results do not provide an accurate picture of the unit cost for resources that would be impacted by the load. The result is a determination of an energy price differential that is inconsistent with FBC's stated objectives and its adopted approach for establishing price differentials.[209]

Determination of TOU Rates

BCOAPO submits that FBC did not provide adequate documentation of how TOU rates were derived. The model provided by FBC set out only the calculation of rate differentials and not the calculation of customer class rates.[210]

Optionality and Eligibility

In BCOAPO's view, offering TOU on an optional basis creates equity issues. Even if some customers make no changes to their usage patterns, they stand to benefit, and all customers will share any revenue shortfalls resulting from this. Therefore, the reality is that participation will be weighted toward those that benefit, with no action being taken with regard to their loads, thereby increasing the likelihood that TOU will fail to provide an overall rate benefit.[211]

BCSEA-SCBC

BCSEA-SCBC opposes approval of the TOU rates related to the residential class. In its view, any expectation of cost-effective load shifting is outweighed by the potential for free-ridership. BCSEA-SCBC raises concern that "customer choice," which it sees as a secondary benefit, is overemphasized in FBC's justification of optional TOU rates and net financial savings to the utility and the customers as a whole are underemphasized. Noting that FBC

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[208] BCOAPO Final Argument, p. 80.
[209] Ibid., p. 81.
[210] Ibid., p. 82.
[211] Ibid., p. 83.

does not argue that TOU rates will reduce peak demand cost-effectively, BCSEA-SCBC argues that the rate cannot be considered a conservation rate. [212]

Noting that participation in the current TOU rate is low, BCSEA-SCBC points out that it is unfortunate FBC did not examine the existing TOU program and include customer perspectives in the current proposal. As an example, it would have been instructive to know the level of free-ridership that exists in the current program.[213]

BCSEA-SCBC asserts an issue with optional TOU rates is they are susceptible to free-ridership while mandatory TOU rates are not. As pointed out by its expert witness Raphals, customers who switch to TOU rates but make no behavioural changes will reduce FBC's revenues but not its costs. However, to be successful, TOU rates need to cause a reduction in the utility's costs that is larger than the deficit related to free-ridership. Noting that 19 percent of residential customers would benefit from the proposed rates without any change in behaviour, BCSEA-SCBC points out that the average lost revenue per free rider would be $34.86 if all potential free riders were to participate.[214]

In BCSEA-SCBC's view, the "available evidence does not support a reasonable expectation that the proposed residential optional TOU rate would be financially successful given the potentially large revenue loss due to free-ridership. Under the principle of class revenue neutrality, this financial loss would be made up in the form of higher rates paid by all residential customers."[215]

BCSEA-SCBC also has reservations with respect to the merits of TOU rates for the non-residential customer classes. Its concerns can be summarized as follows:

- It has not been adequately demonstrated that all rate classes should necessarily receive optional TOU rates at this time;
- There is a risk it might be difficult to modify or eliminate optional TOU rates once in place; and
- The focus on optional TOU rates may result in a reduced consideration of other approaches to load shifting and demand response that may have a higher potential to be successful.[216]

FBC Reply Argument

FBC addresses the concerns raised by BCSEA-SCBC, BCOAPO and KSCA in succession.

BCSEA-SCBC

FBC does not agree with certain conclusions regarding free-ridership and the potential loss of revenues. In FBC's view, "a more accurate conclusion is that any shift in costs between customers would be from those with favourable load shapes to those with unfavourable load shapes which could be regarded as appropriate."[217] FBC points out that the costs are not higher to the class overall and because TOU rates are cost-based, they better

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[212] BCSEA-SCBC Final Argument, pp. 23–25.
[213] Ibid., p. 26.
[214] Ibid., pp. 27–28.
[215] Ibid., p. 30.
[216] Ibid., p. 32.
[217] FBC Reply Argument, p. 50.

reflect differences in costs to serve customers within the class, just as demand charges better reflect cost causation among customers with different load shapes in the large commercial class. In FBC's view, it has provided "ample evidence" regarding the cost-based and load-reflective nature of its proposed TOU rates, pointing to its IR responses which it states have been "largely summarized in its October 17, 2018 Final Submission in Part Seven." [218]

FBC is unclear as to BCSEA-SCBC's position on non-residential TOU rates. BCSEA-SCBC has submitted that there has not been an adequate demonstration that all non-residential rate classes should receive optional TOU rates. FBC responds that all of these rate classes currently have optional TOU rates and where changes have been proposed, they better reflect cost causation.[219]

BCOAPO

Regarding BCOAPO's concerns with TOU pricing differentials, FBC submits that the dispatch of resources is far more complex than simply dispatching resources in the same order all of the time and BCOAPO has failed to recognize this. Specifically, there is a balance of price, availability and contractual requirements that needs to be considered. FBC states that in setting pricing differentials "it was not possible to account for the entire complexity of dispatch of resources." A set of assumptions about what resources could be avoided if loads were reduced in various TOU periods are also reflected in TOU price differentials. [220]

FBC submits that the costs for the resources identified as peak capacity costs were identified for the on-peak period and these can potentially be avoided if loads are reduced over this period. FBC explains that the on-peak price signal was intended to reflect additional costs related to on-peak hours, not the entire cost for the on-peak hours. It is therefore important that it is understood that the calculation which divides by on-peak energy is used to determine the on-peak adder, not the overall on-peak price. FBC continues its explanation by noting that the total on-peak price "includes a price to cover all base load resources, plus an adder for resources used to meet mid-peak loads, plus the adder for costs associated with meeting on-peak loads." With this approach, the net on-peak price does reflect that some peak demand is met by base load resources. [221]

FBC also notes that BCOAPO has questioned how various elements of the FBC resource stack are considered in the establishment of pricing differentials for the various TOU periods. FBC states that the BCOAPO statement with regards to purchases from BC Hydro and the market only being used to meet load requirements in the on-peak and mid-peak periods shows a lack of understanding that the actual dispatch and use of resources in TOU pricing is not so simplistic. FBC explains that the intent of the mid-peak price differential is "to recognize the next set of costs that could be avoided if customers reduce loads in the on-peak and mid-peak periods." The pricing is intended to reflect that costs for base load resources cannot be avoided but it is possible to reduce costs associated with BC Hydro and market purchases. The adder for mid-peak periods is intended to reflect the avoidable cost of those resources when the load is reduced during both of these periods. [222]

[218] FBC Reply Argument, p. 50.
[219] Ibid., p. 50.
[220] Ibid., pp. 50–51.
[221] Ibid., p. 51.
[222] Ibid., pp. 51–52.

FBC states it believes that BCOAPO's concerns with regard to TOU pricing periods and rate determinations are due to a lack of familiarity with the practical considerations FBC must take into account with regard to how it resources its load and the potential for cost savings.[223]

KSCA

FBC notes that KSCA seems to generally be supportive of TOU rates and its reservations are more closely related to the inability of some customers to take advantage of rates to lower their costs. While understanding this concern, FBC asserts that the driver for TOU rates is cost causation, not customer bill savings.

FBC notes that KSCA in its submissions has inappropriately mixed COSA concepts with the TOU rate design, erroneously failing to distinguish between the allocation of costs in COSA and the setting of TOU rates. FBC explains that the goal of TOU pricing is to provide incentive for TOU customers to reduce loads during on-peak periods, thereby reducing the costs to supply the power in those hours, and any class that has load over this period has the potential to reduce that load. If residential customers were not charged the on-peak rate during those hours, it would defeat the purpose of having the rate. [224]

4.2.2.4 Panel Determination

The Panel rejects FBC's proposals to revise and re-open the optional residential TOU rate to all residential customers and revise all other non-residential TOU rates.

The Panel acknowledges that FBC, with assistance from its consultant EES, has expended much effort in examining the current TOU rate program and in making changes which it believes will result in a more effective TOU rate program that is more reflective of the current load profile and related costs. However, the Panel has a number of concerns which, when considered collectively lead us to our determination to reject FBC's proposals. The Panel's concerns are identified and elaborated upon, along with some recommendations as to how they may be addressed under the following categories:

Lack of Examination and Analysis Related to Customer Reaction to Current TOU Rates

Based on the information provided, participation in the current TOU rate program in terms of numbers of customers is limited, with 175 residential and 21 non-residential enrolled. In spite of this rather sparse response over the last 20 years, FBC has not conducted a formal review of the program, nor has it attempted to analyze how the program has performed against the original rationale and presumably objectives put forward at that time. Moreover, FBC has not surveyed its existing customers as to the effectiveness of the program relative to its expectations, nor does it have any idea as to the reasons for the lack of uptake in the program. As a result, we have no knowledge as to how existing customers or those who are no longer in the program feel about it or why they joined in the first place. Nor do we know what level of change in consumption is related to TOU rates. This point was raised by BCSEA-SCBC who pointed out that "it is unfortunate that FBC did not examine the experience with the existing TOU rates, including participants' perspectives, in the course of preparing the current optional TOU proposal" and how it would be instructive to know how much free-ridership exists within

[223] FBC Reply Argument, p. 52.
[224] Ibid., pp. 51–53.

the current program.[225] The Panel agrees. While having a TOU rate may be in keeping with trying to manage conservation, it is pointless to have a program in place that has limited participation and even worse to not know why. The Panel recommends that prior to moving forward with any future application for TOU rates that FBC conduct primary research among its existing customer group to better understand their perspective on the current program, and issues they believe need to be addressed.

Lack of Direct Customer Involvement in Developing New TOU Rates

In addition to the lack of research on existing customers, FBC has conducted no research to understand the concerns and expectations of potential new customers to TOU rates. This could provide insight as to how to best design certain elements of the program and how best to communicate with these new potential customers. For example, FBC has commented that the complexity of rate programs is an important consideration. At the same time, it is recommending moving from the current two TOU time periods to three TOU time periods. Is this an issue for customers? Would it be better understood by having only two time periods? Would this impact the potential uptake of TOU rates? Questions such as these remain unanswered and potentially could have a significant impact on success factors moving forward.

BCSEA-SCBC has raised the issue of free-ridership and has noted that 19 percent of FBC's customers could potentially become free riders.[226] Customer research could potentially inform FBC as to how big this problem is likely to be. Such research can also provide information on the number of customers who would be willing to participate and modify their consumption behaviour in favour of behaviour that is more conservation oriented. This would allow FBC to provide an estimate of how much free-ridership can be offset and if there is any likelihood that FBC's stated objective of creating financial benefit for all customers can be achieved.

Lack of Financial Estimates Regarding the Financial Impact of the TOU Rate Changes

An important element to introducing any rate change is to have an indication of how these changes will affect customers who participate and those who do not. FBC's position has been that it is unreasonable to estimate participation rates prior to implementing the program. The Panel disagrees. Our view is that given the changes that have been proposed and approved with respect to residential rates it is important that diligence is applied to providing some estimates as to the potential impact on residential customers and even some non-residential classes. The Panel accepts that actual experience will provide more accurate tools for future forecasting, but its absence does not preclude the need to provide modelling reflective of the assumptions that FBC has stated it has applied in its development of TOU rates. FBC might consider a series of model impacts ranging from the most likely to less likely outcomes and impacts, and provide explanations as to how these estimates were arrived at.

Scope of the TOU Program

The Panel is not persuaded that a full rollout of TOU rates for a three-year program is the most appropriate approach. If conducted carefully, the desired learning with respect to these rates could just as easily be achieved with a pilot program involving a select number of ratepayers in select areas. Reducing the potential sample size would also reduce the impact in the event of unexpected results and could be easily increased if the initial

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[225] BCSEA-SCBC Final Argument, p. 26.
[226] Ibid., pp. 27–28.

offering had limited participation. Moreover, in the event it was decided that TOU rates should be discontinued, the potential impact on customers who had opted for the rate and were enjoying benefits through free-ridership or other means would be less than a full roll-out across the system. Thus, the number of customers affected would be less.

Lack of Specifics Related to FBC's Goals

BCOAPO has stated that it considers it important for goals and objectives to be clearly established as this will assist in determining an appropriate pricing structure and later, assessing the program.[227] The Panel agrees. In our view it is important at this point to be able to specify what success looks like with specific goals and targets. FBC has stated that the goal of TOU rates is to reduce overall peak demand (not shift loads) which in turn will result in less need for outside power requirements and, at some point, potentially lower requirements for additional generation. FBC has provided no evidence that there will be a need for additional generation, so the Panel concludes that expected savings to achieve the goals and objectives will come exclusively from a reduction in outside power requirements. Prior to the implementation of any trial or pilot TOU program, the magnitude of these reductions in outside power requirements must be specified and how this is to be achieved articulated. This will serve as a basis for analysis following the conclusion of the program's initial trial period.

Optional TOU Program versus Other Alternatives

BCSEA-SCBC has made the case that a consequence of implementing these rates and providing tools to determine whether they will benefit an individual customer is an increase in the number of free-riders. If this proves to be accurate, a greater number of customers willing to modify their consumption behaviours will be required to keep other participating ratepayers whole and offset the impacts of free-ridership. The question that must be considered is whether this is a reasonable expectation under an optional program where the potential for free-ridership is so high.

As an alternative, the Panel notes that under a mandatory TOU rate program the issue of free-ridership is lessened, as the 81 percent of customers whose current consumption behaviours do not allow for free-ridership would be required to shift their loads in order to avoid higher bill impacts. While this may lead to a more readily successful program where the goals and objectives can be met, it must be balanced against the impact of denying customers a choice. Potentially forcing customers who, due to circumstances, have limited ability to change consumption behaviours in a meaningful way may prove onerous. This may be difficult to justify given FBC's stated lack of constraints in meeting its load requirements.

The Panel notes that in its final argument BCSEA-SCBC has observed that FBC's sole focus on TOU rates has potentially precluded examination of other approaches to load shifting and demand response that could be successful. These include options like critical peak pricing and direct (smart) load control which have been chosen by other utilities over optional TOU rates. The Panel notes that these may be worth exploring in the event further analysis dictates that optional TOU rates have little likelihood of success and mandatory TOU rates are likely to result in inequitable treatment of customers.

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[227] BCOAPO Final Argument, p. 75.

FBC's proposal for optional TOU rates has been focused primarily on the methodology, with only limited commentary on the required results. In the view of the Panel, if FBC were to focus on the issues we have raised with TOU rates it will provide further guidance to the methodology which may result in design changes, allowing some of the concerns raised by certain interveners and the BCUC to be resolved.

CleanBC Plan

The Panel acknowledges the BC Government has recently issued its CleanBC Plan which addresses, among other matters, the importance of electrification. We recognize that increased electrification will, all else equal, eventually drive the need for more generation and potentially increase costs to consumers. However, the implementation of an effective TOU rates program presents an opportunity for utilities to better manage the need for new generation, and thereby mitigate these cost increases. The Panel therefore encourages FBC to re-examine its proposed TOU program to more clearly identify the opportunities that exist and to set appropriate goals and objectives that align with the CleanBC Plan policy objectives.

4.2.3 Keremeos Irrigation District TOU Request

FBC explains that during the consultation leading up to the filing of the Application, it received the following request from the Keremeos Irrigation District to consider a further change to the treatment of Irrigation customers:

> We would like to request that FBC incorporate the option to allow Irrigation Customers to utilize [a] "time of use" power rate structure during the non-irrigation season. Incorporating this type of rate structure could reduce peak load demand while also allowing the water suppliers to reduce their power costs.[228]

FBC submits that 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 therefore proposes to further investigate the implementation of an off-season TOU Irrigation and Drainage rate and to report back to the BCUC.[229]

FBC estimates that it will take approximately 60 days to review the load information and incorporate it into a review of the COSA impact and that a six to eight week period would then be used to review the results with Irrigation customers. FBC therefore estimates that it could report to the BCUC within 120 days of the BCUC's decision on this Application.[230]

No intervener made a submission on this request in final argument.

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[228] Exhibit B-1, p. 85; Appendix K.
[229] Ibid., p. 85.
[230] Exhibit B-21, BCUC IR 124.1.

Panel Determination

The Panel accepts FBC's approach to investigating the implementation of an off-season TOU Irrigation and Drainage rate and directs FBC to report to the BCUC on any analysis it has conducted and the results of the investigation and consultation with Irrigation customers within 120 days of the date of this Decision.

4.2.4 Removal of RS 03

As stated above, FBC seeks approval to remove RS 03, which is the RCR Control Group, from the Electric Tariff. The RCR control group was dissolved in 2015 and those customers within the control group were returned to the default residential rate.[231]

No interveners objected to FBC's request to remove RS 03 from the Electric Tariff.

Panel Determination

The Panel approves the removal of RS 03 from FBC's Electric Tariff. This rate schedule is no longer required since the RCR control group was dissolved in 2015; therefore, it is appropriate to remove the rate schedule.

4.3 Commercial Service, Irrigation and Wholesale Rates

4.3.1 Introduction

FBC seeks the following approvals regarding the Commercial Service, Irrigation and Wholesale rate classes:

Small Commercial Service (RS 20):

1. Approval to increase the monthly Customer Charge from $19.40 to $23.00 and to decrease the energy rate from $0.10195 per kWh to $0.10000 per kWh.

Commercial Service (RS 21):

1. Approval to increase the monthly Customer Charge from $16.48 to $54.00.
2. Approval to flatten the energy rate to replace the current declining block rate structure, resulting in an energy rate of $0.06875 per kWh for all consumption.
3. Approval to increase the per-kVA Demand Charge from $7.72 to $10.22.
4. Approval to update the transformation discount from $0.53 per kW of Billing Demand to $0.32 per kW of Billing Demand.

Large Commercial Service – Primary (RS 30):

1. Approval to change the RS 30 transformation discount from $2.676 per kVA of Billing Demand to $5.26 per kVA of Billing Demand.

[231] Exhibit B-1, p. 58; Exhibit B-8, BCUC IR 33.1.

Large Commercial Service – Transmission (RS 31):

1. Approval to increase the monthly Customer Charge from $3,116.03 to $3,195.00 and to decrease the energy rate from $0.05516 per kWh to $0.05367 per kWh.
2. Approval to increase the per-kVA Power Supply Demand Charge from $2.77 to $3.45.

Irrigation and Drainage (RS 60):

1. Approval to increase the Customer Charge from $20.06 per month to $22.09 per month and to decrease the energy rates from $0.07259 per kWh to $0.07240 per kWh.

Wholesale (RS 40):

1. Approval to increase the Customer Charge from $2,645.03 to $4,522.46 and to decrease the energy rates from $0.05441 per kWh to $0.05338 per kWh.
2. Approval to add a discount for RS 40 customers that take delivery at Transmission voltage.

4.3.2 Small Commercial (RS 20) and Commercial (RS 21) Services

Small Commercial (RS 20)

The Small Commercial rate is available to non-residential customers with demand not more than 40 kW. FBC requests approval to increase the Customer Charge to $23.00 per monthly billing period in order to set this charge at 55 percent of the COSA-derived value for fixed costs (currently the fixed cost recovery through the Customer Charge is 46 percent). As a result of this increase to the Customer Charge, FBC requests approval to decrease the energy rate from $0.10195 to $0.10000 per kWh.

Commercial (RS 21)

The Commercial rate is available to non-residential customers with demand more than 40 kW and less than 500 kW.[232]

FBC identifies the following issues which it asserts need to be addressed in this proceeding:

- The Customer Charge only collects 17 percent of the COSA unit cost;
- The Demand Charge only collects 48 percent of the COSA unit cost; and
- 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 submits that a declining block rate structure runs counter to conservation objectives and should be discontinued. It also notes that as part of the 2009 RDA Decision, RS 21 was partially flattened from a three-tier declining block structure to a two-tier structure for the same reason.[233]

FBC provides the following table comparing the existing RS 21 rate to the proposed RS 21 rate:[234]

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[232] Exhibit B-1, p. 76.
[233] Ibid., p. 77.
[234] Ibid., Table 6-15, p. 78.

Table 22: Current and Proposed RS 21 Rate

Rate Schedule 21 Rate Component	Existing Tariff Rate	Proposed Tariff Rate	Proposed COSA Unit Cost Percentage
Customer Charge ($/mo)	16.48	54.00	55%
Tier 1 Energy Rate ($/kWh)	0.08663	0.06875	
Tier 2 Energy Rate ($/kWh)	0.07191		
Demand Rate ($/kVA)	7.72	10.22	65%

In addition to the requests regarding the customer, demand and energy charges for RS 21, FBC also seeks approval to change the transformation discount from $0.53 per kW of Billing Demand to $0.32 per kW of Billing Demand.[235]

FBC states there are currently 31 customers receiving the transformation discount. These customers have chosen to own the transformation equipment required to convert their service voltage from the Primary level to the Secondary level, which is the level that most RS 21 customers take service at. Since the customers who own the required transformation equipment are taking service at the Primary voltage available at the location of the interconnection, these customers are entitled to a discount from the demand charge.[236]

FBC explains that the 2017 COSA Study results were used to establish the difference in costs between the Primary and Secondary voltage levels.[237]

Positions of the Parties

None of the interveners object to FBC's proposed changes to RS 20 and RS 21; however, the CEC recommends a phase-in period for the changes to RS 21. This recommendation is described in Section 4.1 of the Decision.

Panel Determination

The Panel has previously approved the increase to the Customer Charge for RS 20 in Section 4.1 of this Decision. **Given this approval and in consideration of maintaining revenue neutrality, the Panel approves a decrease to the RS 20 energy rate from $0.10195 per kWh to $0.10000 per kWh.**

The Panel has previously approved the increase to the Customer Charge and Demand Charge for RS 21 in Section 4.1 of this Decision and has directed that the changes be phased in. In order to maintain revenue neutrality, a change to the RS 21 energy rate is required. The Panel finds FBC's proposal to flatten the RS 21 energy rate from a two-tier declining block rate to be reasonable. We agree that declining block rates run counter to conservation objectives and therefore consider a flat rate to be better aligned with Bonbright Principle 3 – Price signals that encourage efficient use and discourage inefficient use. **The Panel therefore**

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[235] Exhibit B-1-5, p. 79.
[236] Ibid., p. 79.
[237] Ibid., p. 79.

approves flattening the energy rate to replace the current declining block rate structure, resulting in an energy rate of $0.06875 per kWh for all consumption. The Panel directs that FBC phase in the energy rate in accordance with the Panel's decision in Section 4.1 regarding the Customer and Demand charges.

The Panel approves updating the transformation discount from $0.53 per kW of Billing Demand to $0.32 per kW of Billing Demand. The changes are cost-based and are driven by the results of the 2017 COSA Study, which the Panel has previously found to be reasonable.

4.3.3 Large Commercial Services (RS 30 and RS 31)

Large Commercial – Primary (RS 30)

FBC is not proposing any changes to the Customer, Demand or Energy charges for RS 30 because the fixed charge elements are already at or above the targeted 55 percent (Customer charge) and 65 percent (Demand charge).[238]

FBC is, however, requesting to adjust the transformation discount from $2.676 per kVA of Billing Demand to $5.26 per kVA of Billing Demand. In the case of RS 30, service is normally taken at the Primary voltage and may be taken at the Transmission voltage if the customer chooses to own the associated transformation equipment. Currently, the only RS 30 customer receiving the transformation discount is FEI for service to its Hedley compressor station.[239]

Unlike the RS 21 transformation discount adjustment, the RS 30 discount is increasing. FBC states the increased discount results from growth in costs and higher kVA per customer in the 2017 COSA Study, which results in a near doubling of distribution costs per kVA compared to the 2009 COSA Study.[240]

Large Commercial – Transmission (RS 31)

FBC proposes to redistribute the revenue recovery among the fixed and variable elements of RS 31, consistent with the approach taken for the other rate classes. The impact of the proposed changes is as follows:[241]

Table 23: Current and Proposed RS 31 Rates

Rate Schedule 30 Rate Component	Existing Tariff Rate	Proposed Tariff Rate	Proposed COSA Unit Cost Percentage
Customer Charge ($/mo)	3,116.03	3,195.00	55%
Energy Rate ($/kWh)	0.05516	0.05367	
Wires Charge Demand Rate ($/kVA)	4.93	4.93	67%
Power Supply Demand Rate ($/kVA)	2.77	3.45	65%

238 Exhibit B-1, p. 80.
239 Ibid., p. 80.
240 Ibid., p. 80.
241 Ibid., pp. 81–82, Table 6-20.

FBC explains there are only four customers taking service under RS 31, one of which is a partial-requirements customer (i.e. a self-generating customer that does not rely on FBC for its full requirements at all times). FBC provides the following bill impacts of its proposals on each customer based on the 2016 billing determinants at current rates compared to the proposed rates:[242]

Table 24: 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%

FBC states that Customer No. 4 in the above table is the partial requirements customer and the reason the bill impact is significantly higher for this customer than the other three customers is because Customer No. 4 has a low load factor. FBC also states that contractual demand charges are a significant portion of total billing so the increase in the power-supply demand-charge has a more pronounced impact on Customer No. 4.[243]

Positions of the Parties

With the exception of BCOAPO, none of the interveners raised issues with respect to FBC's RS 30 proposals. BCOAPO argues an adjustment should be made to the Customer Charge. This issue is discussed in Section 4.1 of the Decision.

None of the interveners objected to FBC's RS 31 proposals.

Panel Determination

The Panel approves updating the RS 30 transformation discount from $2.676 per kVA of Billing Demand to $5.26 per kVA of Billing Demand. The changes are cost-based and are driven by the results of the 2017 COSA Study, which the Panel has previously found to be reasonable.

The Panel has previously approved the increase to the Customer Charge and Demand Charge for RS 31 in Section 4.1 of this Decision. In order to maintain revenue neutrality, a change to the RS 31 energy rate is required. **The Panel therefore approves decreasing the energy rate from $0.05516 per kWh to $0.05367 per kWh.**

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[242] Exhibit B-1, Table 6-21, p. 82.

[243] Exhibit B-8, BCUC IR 53.1, 53.2.

4.3.4 Irrigation and Drainage (RS 60) and Wholesale (RS 40) Rates

Irrigation and Drainage (RS 60)

FBC requests approval to increase the Customer Charge from $20.06 per month to $22.09 per month and to decrease the energy rates from $0.07259 per kWh to $0.07240 per kWh for RS 60. Irrigation customers can take service under RS 60 between April 1 and October 31 of each year (the irrigation season). During the non-irrigation season these customers are charged at the applicable commercial rate depending on eligibility, but they remain as part of the Irrigation class for the purpose of cost allocation within the COSA.[244]

Wholesale (RS 40)

Wholesale rates are fully bundled services offered to the municipalities located within the FBC service territory that also operate electric utilities, as well as at a number of points of interconnection with BC Hydro. These customers purchase electricity in order to resell to end-use customers.[245]

FBC offers two default rate schedules as part of its Wholesale rates:

- RS 40 – Wholesale Service – Primary – available to the municipal utilities of Grand Forks, Penticton, Summerland and BC Hydro for service near Lardeau and Yahk.
- RS 41 – Wholesale Service – Transmission – available to the City of Nelson.[246]

FBC requests approval to increase the RS 40 Customer Charge and to decrease the energy rates to maintain revenue neutrality. FBC also requests approval to add a transformation discount to RS 40.[247] With regard to RS 41, FBC proposes no changes, as the fixed cost recovery is already above the target 55 percent/65 percent levels for customer/demand charges.[248]

FBC explains that 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 Nelson Hydro. While the RS 41 discount is based on the 2017 COSA Study, Wholesale – Primary customers are unable to take service under RS 41 because the rate is specific to the service characteristics of the City of Nelson and has no general application to other utilities.[249]

The primary reason FBC is requesting to add the RS 40 transformation discount is that during the consultation that preceded the Application, FBC received correspondence from the City of Grand Forks stating it is considering a change to the voltage at which it takes service. FBC submits the addition of a transformation discount would facilitate this change without the need for process outside of the Application, and the discount would then be available for other wholesale customers.[250]

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[244] Exhibit B-1, p. 82.
[245] Exhibit B-1-4, p. 86.
[246] Ibid., p. 86.
[247] Ibid., p. 87.
[248] Ibid., Table 6-24, p. 86.
[249] Ibid., p. 87.
[250] Ibid., p. 87.

Positions of the Parties

None of the interveners objected to FBC's RS 60 and RS 40 proposals.

Panel Determination

The Panel has previously approved the increases to the Customer Charge and Demand Charge for RS 40 and RS 60 in Section 4.1 of this Decision. In order to maintain revenue neutrality, a change to the RS 40 and RS 60 energy rates are required. **The Panel therefore approves decreasing the RS 40 energy rate from $0.05441 per kWh to $0.05388 per kWh and approves decreasing the RS 60 energy rate from $0.07259 per kWh to $0.07240 per kWh.**

The Panel approves the addition of a transformation discount for RS 40 customers that take delivery at Transmission voltage. The Panel agrees that approval of this discount will facilitate the change being considered by the City of Grand Forks and the discount would then be available for other Wholesale customers in the future.

4.4 Transmission Services

FBC applies for two changes to its transmission services rate design: changes to the tariff language for rate schedules RS 101 and RS 102, and updates to the prices for the Point-to-Point (PTP) transmission rates and related ancillary services.

FBC originally applied for the closure of RS 102, but in its final argument FBC withdrew that request.[251] The Panel will not consider the request to close RS 102 any further in this Decision.

4.4.1 Rate Harmonization for RS 101 and RS 102

FBC applies to add language to the RS 101 tariff schedule for the Annual Rate for Long-Term Firm Service as follows:

> The Monthly Rate is billed on the sum of the Reserved Capacity at each POD. The Monthly Rate will be zero ($0.00) where the POD is a point of interconnection between the Transmission System and the transmission system of the B.C. Hydro and Power Authority, <u>and the power is being delivered to a load within or beyond the B.C. Hydro service area. For clarity, the zero rate is not available for the delivery of power to the BC Hydro system where there is no equivalent point-to-point transmission reservation on the BC Hydro system</u>.[252] (Emphasis in original indicating proposed text to be added)

FBC also applies to add language to the RS 101 tariff schedule for the Annual Rate for Short-Term Firm Service as follows:

> The posted prices will be above a minimum price and below a maximum price as set out below; except that the Monthly, Weekly, Daily or Hourly Rate, as applicable, will be zero ($0.00) where

[251] FBC Final Argument, p. 27.
[252] Exhibit B-1, p. 95.

> the POD is a point of interconnection between the Transmission System and the transmission system of the B.C. Hydro and Power Authority, <u>and the power is being delivered to a load within or beyond the B.C. Hydro service area. For clarity, the zero rate is not available for the delivery of power to the BC Hydro system where there is no equivalent point-to-point transmission reservation on the BC Hydro system</u>. [253] (Emphasis in original indicating proposed text to be added)

Finally, FBC applies to add language to the RS 102 tariff schedule for the Short-Term Non-Firm Service as follows:

> The Transmission Customer shall pay for Non-Firm Point-to-Point Transmission Service at rates not to exceed the applicable charges set forth below; except that the Monthly, Weekly, Daily or Hourly Rate, as applicable, will be zero ($0.00) where the POD is a point of interconnection between the Transmission System and the transmission system of the B.C. Hydro and Power Authority, <u>and the power is being delivered to a load within or beyond the B.C. Hydro service area. For clarity, the zero rate is not available for the delivery of power to the BC Hydro system where there is no equivalent point-to-point transmission reservation on the BC Hydro system</u>.[254] (Emphasis in original indicating proposed text to be added)

The applied-for changes to RS 101 and RS 102 will collectively be referred to as the Proposed Changes.

FBC submits the Proposed Changes are required because the original versions of the tariff schedule may be interpreted incorrectly in circumstances not anticipated when the tariff was originally approved, "with the potential to lead to FBC being deprived of appropriate revenue that could be used to lower rates for load customers."[255]

FBC adds it has discussed the Proposed Changes with BC Hydro, who has confirmed that the revised tariff language is consistent with the principles that the two utilities together used when RS 101 and RS 102 were originally created.[256]

FBC explains that during its first application for approval of transmission access for industrial and municipal customers, at the BCUC's behest, FBC (then West Kootenay Power [WKP]) and BC Hydro jointly proposed tariff language to "relieve transmission service customers from the requirement to pay both B.C. Hydro's and FBC's transmission wheeling rates by charging only the transmission service rate of the utility within whose service area the customer taking service is located." [257] This principle, whereby customers would pay transmission wheeling rates to just one utility is known as "anti-pancaking", or "rate harmonization".

According to FBC, no entity has ever used FBC's transmission services for wholesale or retail access as originally envisioned. However, the RS 101 schedule has been used by self-generation customers and independent power producers (IPP) to export power. FBC submits its Proposed Changes are required to avoid the situation where a

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[253] Exhibit B-1, p. 96.
[254] Ibid., p. 96.
[255] Ibid., p. 92.
[256] Ibid., p. 92.
[257] Ibid., p. 93; Applications by West Kootenay Power Ltd. and British Columbia Hydro and Power Authority for Approval of Rate Harmonization on their Transmission Systems, Order G-12-99, Recital C.

transmission customer located within the FBC service area pays no wheeling fee to either FBC or to BC Hydro when wheeling power to BC Hydro where BC Hydro is using that power to serve its network load.[258]

FBC submits the original intent of the anti-pancaking language was to harmonize the transmission rates between FBC and BC Hydro, thus ensuring that customers avoid paying both utilities' wholesale transmission rates when wheeling power between the two utilities' service territories. As a result of the current language being misinterpreted, FBC claims it currently has two self-generating customers that are exporting power to BC Hydro and paying no transmission-related charges except for certain ancillary services.[259]

ICG submits evidence from Will Cleveland regarding the impact of the Proposed Changes on power exporters. Cleveland notes:

> For future exporters of power from FBC's service area (or for existing generators seeking, in future, to export power or renew their power export arrangements), the Proposed Changes will have the following consequences:
>
> - Exporting power to BC Hydro will now require paying FBC's full point-to-point transmission charge. This is in addition to any directly assigned transmission costs – for example, to integrate a new generation resource into the FBC grid. Directly assigned costs would be separately recovered from the generator through a connection charge or similar fee. The point-to-point transmission rate is purely a contribution towards sunk costs. In the absence of any generators seeking to export power (or any other wheeling transactions), all sunk transmission costs would be recovered from FBC's loads.
> - BC Hydro – which is the service area where most of the load growth in BC is anticipated to occur – will take these transmission charges into account when comparing energy supply options. If a generator located within FBC's service area seeks to export power to BC Hydro, any export transaction would attract FBC's full point-to-point transmission charge, even though the generator would have separately paid (through direct assignment) any costs incurred to incorporate their generation into the grid. This generator will have to compete against generators located within BC Hydro's service area, who can sell to BC Hydro without making a contribution to embedded transmission costs, as these costs are recovered from BC Hydro's loads, not from generators located within BC Hydro's service territory.
>
> The additional charges under the Proposed Changes may be sufficient to distort generation procurement decisions…[260]

ICG also submits evidence from Elroy Switlishoff regarding representations made by FBC to Zellstoff Celgar Limited Partnership (Celgar):

> The current interpretation of the non-pancaking provision in Order G-12-99 has been consistently applied by FBC to Zellstoff Celgar's power exports and was a fundamental

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[258] Exhibit B-1, p. 94.
[259] Order G-12-99, p. 95.
[260] Exhibit C12-6, Cleveland Testimony, p. 4.

assumption in Zellstoff Celgar's 2008 decision to build additional generation for the purpose of selling the generated electricity to BC Hydro. Exhibit B, the letter … dated June 30, 2006 from Don Debienne of FBC to Brian Merwin of Mercer International specifically confirmed that the transmission rate for electricity delivered to "the Point of Delivery, the Kootenay Interconnection is an interconnection with BC Hydro, provided that 71L rights are not being exercised, and as such, the monthly rate charged under Rate Schedule 101 will be $0.00." The Letter enabled exports via FBC's transmission system for the period from July 1, 2006 to October 31, 2006.[261]

Position of the Parties

FBC argues that BC Hydro takes a similar view to FBC on the intent of the anti-pancaking provisions. FBC submits that BC Hydro has business practices in place that achieve the same results as the Proposed Changes, and that BC Hydro confirms that the Proposed Changes correctly reflect the intent of the original application for transmission access.[262]

BC Hydro submits the BCUC can and should accept FBC's Proposed Changes solely for the reasons identified by FBC in its final argument. BC Hydro adds that it does not propose the BCUC conduct a review of rate harmonization at this time, since the matter raises complex issues and there is no compelling reason at this time for such a review.[263]

BCSEA-SCBC takes no position regarding FBC's Proposed Changes to the transmission services tariffs.[264]

The CEC submits the BCUC should accept the Proposed Changes from FBC, since it is inappropriate for FBC to forgo wheeling revenues to the detriment of other ratepayers, and the Proposed Changes clarify the tariffs without making unnecessary changes.[265]

BCOAPO also agrees that the BCUC should accept the Proposed Changes from FBC.[266]

ICG argues the Proposed Changes should not be approved and provides several reasons for its position as follows.[267]

Firstly, ICG submits that the process by which the Application has been reviewed is procedurally unfair. To support this allegation, it questions whether FBC is applying for a "clarification" in the meaning of section 53(3) of the *Administrative Tribunals Act*. Alternatively, ICG suggests that FBC's Application for the Proposed Changes should have been filed as a reconsideration of Order G-12-99, the decision which approved the original rate

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[261] Exhibit C12-6, Switlishoff Testimony, p. 3.
[262] FBC Final Argument, p. 27.
[263] BC Hydro Final Argument, p. 2.
[264] BCSEA-SCBC Final Argument, p. 34.
[265] CEC Final Argument, p. 38.
[266] BCOAPO Final Argument, p. 71.
[267] ICG Final Argument, p. 3.

harmonization tariff language.[268] It adds that procedural fairness requires that the BCUC conduct a "full process in accordance with the guidelines established by the [BCUC]".[269]

ICG argues that FBC customers such as Celgar have relied on Order G-12-99 when making investment decisions, and that FBC's billing practices have consistently applied the tariff language approved in Order G-12-99 ever since it was approved. ICG relies on its evidence that FBC executives have stated to customers that FBC will apply the tariff according to Order G-12-99. [270]

Secondly, ICG submits that FBC's Proposed Changes do not align with the overall intent of Order G-12-99. ICG observes that FBC's Proposed Changes introduce the notion that a point-to-point reservation is required for transmission customers to receive the $0 rate, and argues such a condition was not contemplated in the proceeding that led to Order G-12-99 or in the Order itself.

Thirdly, while ICG agrees with FBC that the licence plate approach approved by Order G-12-99 is appropriate, it disagrees that the Proposed Changes are consistent with such an approach. ICG relies on the evidence of Cleveland, who opines that the Proposed Changes would "require certain end-use customers…to pay the full cost of both utilities' transmission systems for any energy they receive which is procured from a generator located within the other utility's service area," resulting in "transmission rate pancaking for certain customers."[271] Thus, Cleveland concludes the Proposed Changes are "not a consistent application of the licence plate approach and are not in line with how the licence plate approach has been applied in other jurisdictions."

Fourthly, ICG claims the Proposed Changes are discriminatory, because, it alleges, the changes are "a targeted and concerted effort to recover additional revenues from a single customer." The evidence ICG relies on for this accusation is that FBC presently has only two self-generation customers taking service under RS 101, one of whose revenues are "not material."

ICG further explains that the Proposed Changes are discriminatory because they treat self-generators in FBC's service territory differently depending on whether they are selling to BC Hydro or selling to another customer in BC Hydro's territory. Relying on Cleveland's submission,[272] ICG submits that under the Proposed Changes a self-generator in FBC's territory selling power to BC Hydro will pay FBC's wheeling rate to transmit its power to the point of interconnection between FBC and BC Hydro, whereas another self-generator in FBC's territory selling power to a BC Hydro wholesale customer would be entitled to FBC's wheeling rate of $0 to the same point of interconnection.

Fifthly, ICG argues if the BCUC were to approve the Proposed Changes, then one of the two self-generation customers would experience an annual bill increase of 32 percent,[273] which is significantly above the commonly-accepted threshold of 10 percent for rate shock, and on that basis ICG argues the Proposed Changes should be denied.

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[268] ICG Final Argument, p. 5.
[269] Ibid., p. 7.
[270] Exhibit C12-6, Switlishoff Testimony, p. 3.
[271] ICG Final Argument, p. 9.
[272] Exhibit C12-6, Cleveland Testimony, p. 11.
[273] ICG Final Argument, p. 11.

Sixthly, relying on evidence from Cleveland, ICG argues the Proposed Changes may distort generation procurement decisions. Cleveland states that most load growth in BC is anticipated to occur in BC Hydro's service territory, and generators in FBC's territory exporting power to BC Hydro will face transmission charges as a result of the Proposed Changes, unlike generators in BC Hydro's service territory.

ICG finally submits that, should the BCUC approve the Proposed Changes, then a broader review of rate harmonization will be warranted, for the reasons advanced by BC Hydro in its evidence.[274]

In reply, FBC addresses each of the arguments made by ICG, noting that no other intervener was opposed to the Proposed Changes.

With regard to the alleged procedural unfairness, FBC submits the Proposed Changes were clearly set out in the Application, and the current proceeding has provided ICG an opportunity to submit IRs to both FBC and BC Hydro, to submit evidence of its own, and to file "lengthy written submissions."[275] FBC notes that ICG has not explained how it would have presented its case differently in a different form of proceeding.

FBC observes that the section of the *Administrative Tribunals Act* referred to by ICG does not apply to the BCUC pursuant to section 2.1 of the UCA, thus the process for the clarification of a decision referred to in the *Administrative Tribunals Act* is not appropriate.

FBC submits there is no reason the Proposed Changes should be treated as a reconsideration of Order G-12-99. It explains that utility rate schedules are frequently changed and amended by application, and section 61(2) of the UCA specifically contemplates this approach. FBC adds that ICG misconstrues the nature of a reconsideration proceeding, since FBC is not seeking to rescind or vary Order G-12-99, nor is any error of fact or law by the BCUC being alleged by FBC. Rather, FBC is applying to amend the tariff language in a manner consistent with the intent being the original decision.

FBC rebuts ICG's argument that it is procedurally unfair that Celgar has relied on Order G-12-99 and on the representations of FBC executives in making its investment decisions by observing "there are no participatory rights in this proceeding that are impacted in any way by past billing practices or by Celgar's purported reliance on a previous BCUC order."[276]

FBC adds that Celgar could not have had any legitimate expectation that it could rely indefinitely on the tariff set out as a result of Order G-12-99. FBC points to Celgar's current agreement with FBC which does not refer to a $0 charge for wheeling under RS 101, but instead provides that the transmission charge will be "as amended from time to time."[277]

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[274] ICG Final Argument, p. 15.
[275] FBC Reply Argument, p. 59.
[276] Ibid., p. 59.
[277] Ibid., p. 60.

FBC disagrees with ICG's submission that the Proposed Changes do not align with the overall intent of Order G-12-99. FBC replies that the purpose and intent of G-12-99 is clear, namely "to eliminate rate stacking or 'pancaking' – that is, <u>the payment by customers of two transmission wheeling tariffs</u> on transactions where power is moved between utility service areas," and "to relieve transmission customers from the requirement <u>to pay both BC Hydro's and [FBC's] transmission wheeling rates</u> by only charging the transmission service rate of the utility within whose service area the customer taking service is located."[278]

FBC adds that FBC customers exporting power to BC Hydro use only FBC's transmission system to wheel power, and thus there is no pancaking of wheeling rates. FBC concludes the intent of the BCUC in Order G-12-99 was clearly not to permit FBC customers to use FBC's transmission system to export power to BC Hydro without paying for any transmission wheeling service.

FBC observes that the Decision and Order G-12-99 do not refer to generators exporting power, but instead refer to the issue of revenue shifting as a result of customers using transmission services to take delivery of power. FBC argues this supports its conclusion that Order G-12-99 has only concerned itself with customers using RS 101 to receive power, and has not addressed the situation of generation customers using RS 101 to supply power.

FBC disagrees with ICG's position that the Proposed Changes are not consistent with the licence plate approach approved by Order G-12-99. FBC takes the position that since a self-generator in FBC's territory selling to BC Hydro does not pay any wheeling rate to BC Hydro, and since FBC's transmission system is being used to wheel the power to BC Hydro's territory, FBC should receive a wheeling rate for that service, and there is no pancaking to be avoided.

FBC challenges the opinion of Cleveland, whose evidence is cited by ICG in support of the position that the cost of transmission within the BC Hydro system is being paid for by BC Hydro load customers, and hence the Proposed Changes would cause those load customers to pay the full cost of both utilities' transmission systems. FBC submits there is no evidence or reason to expect the Proposed Changes will lead to BC Hydro's load customers paying the full cost of FBC's transmission system. Rather, the Proposed Changes merely mean that self-generators in FBC's service territory will pay for FBC's wheeling services in future.

FBC disputes ICG's allegations that the Proposed Changes are discriminatory. FBC submits it is reasonable to expect increased interest in or proliferation of self-generation in its service territory, and so clarification of the wheeling tariffs that would apply to all such customers is appropriate.[279] Further, FBC replies that ICG's discrimination argument based on Cleveland's scenario analysis is without merit. Under the UCA, discrimination occurs between customers with "substantially similar circumstances and conditions for service of the same description." FBC observes that the two scenarios presented by Cleveland, one involving a self-generator in FBC's territory wheeling power via BC Hydro's territory to serve a load in the US and the other involving a self-generator in FBC's territory wheeling power to BC Hydro to serve load in BC Hydro's territory, are quite different, inasmuch as a self-generator selling to BC Hydro does not wheel power within BC Hydro's territory, and thus the anti-pancaking principles do not apply.

[278] FBC Reply Argument, p. 62.
[279] Ibid., p. 65.

FBC denies that rate shock applies in this case, as the Proposed Changes do not increase rates; rather, they change the circumstances in which the rates are charged. In the particular case of Celgar, FBC points out that if the Proposed Changes are approved for the reasons FBC provides, then Celgar will have received a "multi-million dollar windfall" for its prior use of FBC's wheeling services at no cost.

Panel Determination

For the reasons provided below, the Panel approves the Proposed Changes to the tariff for RS 101 and RS 102 as applied for by FBC. However, the Panel finds that the Proposed Changes constitute rate shock for at least one current customer of RS 101, and finds that it is appropriate to mitigate the effects of this shock. **We therefore direct that FBC phase-in the rate impact of the Proposed Changes over three years and apply the phase-in period for all applicable customers taking service under RS 101.**

Additionally, the Panel recommends that the BCUC establish a proceeding to conduct a broader review of transmission rate harmonization, as discussed in greater detail below.

Intent and Substance of Order G-12-99

The Panel finds that the intent of Order G-12-99 is clear: the BCUC sought to avoid a transmission customer paying wheeling charges to both BC Hydro and to FBC when moving power between the two utilities' service areas. The intent was that such transmission customers would pay exactly one wheeling charge, not two and not zero.

In the reasons for its decision accompanying Order G-12-99, the BCUC stated that the approved rate harmonization scheme would ensure "the transmission customer is charged only the transmission wheeling rate of the utility within whose service territory the customer is located." The reference to the transmission customer being "charged" clearly indicates that there is an intent that transmission customers are to be charged for wheeling services, and does not provide any support for the notion that wheeling services are to be provided for free. Further, the use of the word "only" and the singular use of the noun "utility" clearly indicate the intention that transmission customers are to be charged no more than once.

The BCUC, when describing its intent behind Order G-12-99, made no distinction between transmission customers wheeling power into their service territory and those wheeling power out of it. This Panel finds this to be reasonable, and the principle that transmission customers should pay exactly one wheeling rate to move power between utilities' service territories should not depend on the direction of flow of that power.

The rate harmonization scheme proposed by the utilities, and approved by the BCUC in Order G-12-99, was that when moving power between service territories, transmission customers would pay wheeling charges to the utility in whose service territory they reside. This is known as the licence plate approach, an analogy to vehicle owners paying for licence plates in the jurisdictions in which they reside and being able to travel to other jurisdictions without further licence payments.

To achieve the licence plate approach to rate harmonization, the utilities both amended their transmission wheeling rates such that wheeling power to a point of interconnection with the other utility was charged at $0. The rate to wheel power beyond the point of interconnection would remain. The net effect of these harmonization changes was, and remains today, that a transmission customer bringing power into the service territory in which it resides from a generation source in the other service territory pays the wheeling rate of the utility in whose service territory the transmission customer resides.

The Situation FBC is Addressing

The situation FBC raises in the Application, which it submits is not addressed by Order G-12-99, is as follows. Consider a transmission customer in one utility's service territory who is generating power and selling that power to the utility of the adjacent service territory. This transmission customer would use the transmission services of the territory in which it resides to wheel power as far as the point of interconnection with the adjacent territory, which attracts a rate of $0 under the current FBC and BC Hydro tariffs. However, there would be no corresponding transmission of power by the transmission customer beyond the point of interconnection, since the utility purchasing the power takes ownership of the power at the point of interconnection. Thus, this transmission customer would pay no wheeling rate to either utility.

In this situation, the transmission customer is not at risk of rate pancaking, since the power is being wheeled to the point of interconnection, and the transmission customer has transmission agreements with only one utility. However, despite there being no risk of the transmission customer paying two utilities for wheeling the power, the tariffs for RS 101 and RS 102 as currently worded specify a wheeling rate of $0. The Panel finds this is not a matter of interpretation; this is a plain reading of the current tariff language.

As FBC has argued, and only ICG has disputed, in this situation neither utility is collecting wheeling revenues to contribute to the costs of the transmission system. Under the licence plate approach, if the transmission customer in this situation is in FBC's service territory, then the transmission customer should be paying wheeling rates to FBC.

The Panel agrees with FBC that the situation it describes is not addressed in Order G-12-99, and that FBC's Proposed Changes are consistent with the intent of that Order. Transmission customers in FBC's territory who generate power and sell that power to BC Hydro will in the future, as a result of the Proposed Changes, pay FBC for wheeling power to the point of interconnection with BC Hydro, and will pay no wheeling rate to BC Hydro. This is consistent with the licence plate approach that was approved in Order G-12-99, inasmuch as transmission customers pay exactly one wheeling rate to transmit energy, and they will pay it to the utility in whose service territory they reside. However, since in this situation there is only one wheeling rate, the issue of rate pancaking does not arise.

Therefore, the Panel approves the Proposed Changes to RS 101 and RS 102, subject to the modifications set out below. The Panel notes BC Hydro has confirmed that the Proposed Changes will ensure that FBC's transmission wheeling rates are consistent with those of BC Hydro.

ICG's Concerns

The Panel disagrees with ICG that the process to review the Proposed Changes was unfair. As FBC has observed, the Proposed Changes were clearly laid out in the Application, and ICG has had the opportunity to submit evidence and IRs, and to provide argument. The Panel also rejects ICG's position that the Application should have been submitted as a reconsideration. Proposed tariff and rate changes are typically submitted as applications under section 61 of the UCA, and FBC in this Application has made no request to vary or rescind Order G-12-99. To the contrary, FBC relies on the intent laid out in that Order.

The Panel acknowledges that customers such as Celgar may have relied on the transmission tariffs which were in place when they made investment decisions and when they negotiated contracts to sell power to BC Hydro or to other customers. That said, the Panel believes that customers must reasonably expect tariffs to change from time to time, and ICG has presented no compelling evidence that FBC or its executives ever purported to claim tariffs would remain unchanged indefinitely. To the contrary, FBC has demonstrated that its agreements with Celgar explicitly acknowledge that tariffs might be "amended from time to time."[280] **For these reasons, the Panel dismisses ICG's claim that the Proposed Changes should be rejected because FBC customers relied on the tariff.**

The Panel rejects ICG's arguments that the Proposed Changes are not consistent with Order G-12-99. ICG notes, correctly, that Order G-12-99 does not refer to point-to-point transmission reservations. However, this is beside the point. The Proposed Changes introduce the notion of point-to-point transmission reservations as a way to distinguish a specific situation which was not envisioned by Order G-12-99. Once this specific situation is identified in the tariffs, the effect of the Proposed Changes is to ensure that transmission customers in the identified situation pay exactly one wheeling rate, as envisioned in the licence plate approach approved by Order G-12-99.

The Panel also dismisses ICG's argument that certain end-use customers will pay the cost of both utilities' transmission systems as a result of the Proposed Changes, which amounts to rate pancaking. As FBC has argued, there is no compelling evidence that any BC Hydro end-use customers will pay for FBC's transmission system costs as a result of the Proposed Changes, merely that FBC's self-generating customers will in the future contribute to these costs. In any event, the Panel considers that rate pancaking arises when one transmission customer is paying two wheeling rates, not to situations where multiple parties may be contributing to one set of transmission costs. Thus, we find that the objection raised by ICG is not relevant.

ICG has argued that the Proposed Changes are discriminatory, because they only apply to a "single customer." However, ICG also acknowledges that the Proposed Changes apply to two self-generating customers, while only having a material effect on one of them. The Panel does not agree that the Proposed Changes constitute discrimination. The Proposed Changes apply to all RS 101 and RS 102 customers equally. The fact there are only two self-generating customers taking service under these tariffs, and that one of them uses that tariff less than the other, in no way demonstrates to this Panel that any customers are experiencing discrimination by FBC.

[280] FBC Reply Argument, p. 61.

Further, the Panel finds that ICG's allegation, that self-generators in FBC's territory who sell to BC Hydro are being discriminated against compared to self-generators in FBC's territory who sell to other customers in BC Hydro's service territory, is also without merit. In the former case, the self-generator wheels power to the point of interconnection with BC Hydro, and no further, thus the self-generator is not at risk of rate pancaking. By contrast, in the second case the self-generator wheels power across FBC and BC Hydro service territories, and would be at risk of rate pancaking were it not for anti-pancaking provisions. The Panel does not find it discriminatory that anti-pancaking provisions only apply to customers at risk of rate pancaking.

Transition for Existing Customers of RS 101 and RS 102

The Panel has approved the Proposed Changes to RS 101 and RS 102, but is concerned about the transition of current RS 101 customers to the new tariff.

As stated previously, the Panel finds that the Proposed Changes constitute rate shock for at least one current customer of RS 101, and finds that it is appropriate to mitigate the effects of this shock. ICG states that one of the two self-generation customers in FBC's service territory might experience a total bill increase of 32 percent. FBC does not dispute the size of the bill increase, but responds that this customer will have received a multi-million dollar windfall in previous years. The Panel agrees with ICG that the Proposed Changes constitute rate shock, using the commonly-accepted threshold of 10 percent as the annual bill increase above which rate shock occurs. The Panel does not agree that any "windfall" the customer may have experienced in previous years is relevant to the issue of rate shock.

The Panel finds the Proposed Changes constitute an abrupt change to the circumstances for FBC's current RS 101 customers. The Proposed Changes do not merely increase wheeling rates, they are the application of wheeling rates to a situation in which there were previously no wheeling rates. While the Panel does not consider that customers can reasonably expect tariffs to remain unchanged indefinitely, the Proposed Changes are abrupt for customers such as Celgar who have been accustomed to the current tariff, and FBC has made no proposal for how the effects on current customers might be mitigated.

The Panel finds that three years is a reasonable implementation period for the Proposed Changes. Should the BCUC follow this Panel's recommendation, which is further outlined below, and conduct a broader review of transmission rate harmonization, such a proceeding would most likely be concluded within three years. Likewise, three years is a reasonable period for current RS 101 customers to adapt to the new tariff.

Broader Review of Rate

ICG argues that if the Proposed Changes are approved, then a broader review of rate harmonization will be warranted. The Panel agrees with ICG for the following reasons.

BC Hydro has provided reasons for a review of rate harmonization in its response to BCUC IR 1.3:

1. **OATT [Open Access Transmission Tariff] Evolution:** BC Hydro believes there are issues related to development of the OATT since the adoption of rate harmonization under Order No G-12-99. As an example, in response to an IR asked in the original rate harmonization proceeding, BC Hydro and FBC stated that "the energy imbalance charge will be collected by the utility in whose service territory the load is located." However, the transmission tariffs of the two utilities on their face would seem to allow the transmission customer to choose from which utility it obtains energy imbalance service despite the

joint commitments made by BC Hydro and FBC. In Attachment 1 to BCUC IR 1.3, BC Hydro provides a joint response dated January 6, 1999 to BCUC IRs under the 1998 rate harmonization joint application;

2. **BC Hydro Retail Access:** Per Order No. G-36-14 issued on March 13, 2014, there is currently no retail access in BC Hydro's service area. As a result, only the few wholesale customers in BC Hydro's service area could take advantage of rate harmonization into BC Hydro's service area from FBC's service area, with the $0 rate applied by FBC. Because of this, BC Hydro believes that the revenue transfer associated with retail access or wholesale supply from FBC's service area will have little possibility to benefit BC Hydro ratepayers through BC Hydro point-to-point charges. A broader review of rate harmonization should deal with whether and the extent to which ratepayers and shareholders of each utility can be kept whole in light of Order G-36-14;
3. **Operational:** FBC has, to date, not implemented an open access same time information system (OASIS). While this may not have been a significant issue as long as there is no significant PTP usage over the points of interconnection (POIs), it may become an issue of transparency if there is more extensive PTP usage over the POIs. Put another way, BC Hydro currently has no visibility into FBC's provision of open access transmission services, contrary to OATT principles. For example, there will be no OASIS transmission service request (TSR) on the FBC system that can be compared with a TSR on the BC Hydro system in order to confirm appropriate application of rate harmonization; and
4. **Today's Markets:** The appropriateness of rate harmonization in BC has not been revisited in light of the fact that markets did not develop as expected as a result of deregulation of the industry around the time of Order G-12-99. These expected developments included significant retail access usage in BC and the formation of Regional Transmission Organizations (RTOs) within the Western Interconnection, with centralized transmission planning and operations. These developments did not occur in BC. Indeed, the British Columbia Transmission Corporation was formed based on these expected developments and has subsequently been re-integrated into BC Hydro. BC Hydro is not aware of rate harmonization being adopted as was originally contemplated almost twenty years ago.[281]

While BC Hydro in its final argument withdrew its support for a broader review of rate harmonization at the present time due to the complexity of the topic and the lack of an urgent need, the Panel considers BC Hydro's logic for a broader review to be reasonable. The matter may indeed be complex, but the issues BC Hydro has raised demonstrate possible risks to ratepayers of under-recovery of transmission costs, among other risks.

Further, the Panel believes there is a possible inconsistency in the current transmission rate harmonization scheme not identified by the two utilities, which is unrelated to and not addressed by the Proposed Changes. The Proposed Changes address the situation of a self-generator in FBC's service territory wheeling power to the point of interconnection with BC Hydro and then selling power to BC Hydro. The Panel has already found that the Proposed Changes implement the intent of Order G-12-99. However, for a self-generator in FBC's service territory wheeling power to BC Hydro's territory and selling that power to a wholesale customer in BC Hydro's territory, the current tariffs direct that the self-generator would pay BC Hydro's wheeling tariff. However, the licence plate approach approved in Order G-12-99 directs that the transmission customer should pay the wheeling rate of the utility in whose service territory it resides, which in this case would be FBC's. The Panel

[281] Exhibit C1-4, BCUC IR 1.3.

does not have the evidence to explore this issue in this proceeding, but believes it would be valuable for the BCUC to do so in a separate proceeding.

The Panel finds that the Proposed Changes have the potential to make a difference in the market for power generation in BC. As ICG has argued, based on the evidence from Cleveland, BC Hydro's future decisions to purchase power from IPPs might be influenced by the service territory of the generator, as generators in FBC's service territory must incur transmission costs to wheel power to the point of interconnection with BC Hydro's territory. While the Panel has not found that this constitutes discrimination on FBC's part with regard to transmission tariffs, the Panel does consider that the Proposed Changes may have unintended consequences that have not been adequately explored.

Finally, in the reasons for decision accompanying Order G-12-99, the BCUC expressed concern that the licence plate approach to rate harmonization was not a method that could survive indefinitely, owing to the risk of revenue responsibility shifting between utilities at an unacceptable level. The BCUC also declined to approve rate harmonization for losses and ancillary services in Order G-12-99, in part because of the lack of permanency of the licence plate approach.

For the foregoing reasons, the Panel recommends that the BCUC establish a proceeding to inquire into the broader issues of transmission rate harmonization, with the involvement of transmission owners and transmission customers in the Province.

4.4.2 Transmission Services Discounting

In its final argument, ICG states that FBC has not defined a methodology for calculating discounts for transmission services under RS 101. Quoting evidence from Cleveland, ICG suggests that certain types of discounts might avoid "unnecessary investment in redundant infrastructure."[282]

In reply, FBC concludes that "what ICG is suggesting is not so much a discount as it is a negotiated transmission rate outside of the tariff process." Using the example cited in ICG's evidence, FBC states that in this instance, the "proponent filed a separate application with the BCUC in accordance with the existing Bypass Rate Guidelines." FBC further states that in the case where a bypass situation contemplated by the Bypass Rate Guidelines occurs, filing a separate application is the "appropriate action and is not a rationale for changing the previously approved discounting provisions."[283]

Panel Determination

The Panel agrees with FBC that ICG's request appears to relate more to negotiating a transmission rate than to the discounting provisions contained in the tariff**. We therefore decline to take the actions requested by ICG as the issue raised by ICG is outside the scope of this proceeding.**

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[282] ICG Final Argument, p. 14.
[283] FBC Reply Argument, pp. 82–83.

4.4.3 Updates to Pricing of Transmission and Ancillary Services

FBC proposes eliminating the RS 101 and RS 102 transmission customer charge and updating the pricing according solely to connection voltage without regard for whether the customer is classed as Commercial or Wholesale. The current and proposed pricing is provided in the following table:[284]

Table 25: Current and Proposed PTP Transmission Rates

	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

FBC proposes updating its ancillary services rates (RS 103, RS 104, RS 105, RS 106, RS 107, RS 108 and RS 109) as follows:[285]

[284] Exhibit B-1, Table 7-8, p. 106.
[285] Exhibit B-1, Table 7-9, p. 106.

Table 26: Current and Proposed Ancillary Services Rates

			Large Commercial Service Transmission	Wholesale - Primary	Wholesale - Transmission	Primary	Transmission
			Current Rates			Proposed Rates	
Scheduling, System Control and Dispatch Service	103	Per kWh	\$0.00126	\$0.00132	\$0.00126	Monthly: \$0.1669/kW Weekly: \$0.0385/kW Daily: \$0.0055/kW Monthly: \$0.00023/kW	
Reactive Supply and Voltage Control from Generation Sources Services	104	Per kWh	\$0.00141	\$0.00132	\$0.00132	\$0.825 per MW of Reserved Capacity per hour.	
Regulation and Frequency Response Service	105	Per MW per hour of generating capacity; minimum of 2% of the Customer's load	\$13.62			\$9.31	
Energy Imbalance Service	106		\$0.05043	\$0.0480	\$0.04798	See Tariff Pages	
Operating Reserve (OR) - Spinning Reserve Service	107	Minimum level of service required per Tariff	\$13.62			\$9.31	
Operating Reserve (OR) - Supplemental Reserve Service	108	Minimum level of ervice required per Tariff	\$13.62			\$9.31	
Transmission Losses	109		6.08%	11.53%	6.08%	4.26%	2.86%

Positions of the Parties

No interveners contested FBC's application for any of the proposed rate changes, with the exception that ICG requested the BCUC back-date approval of the change to RS 109 to January 1, 2018.

FBC responds that there is no justification for making the change to RS 109 retroactive to January 1, 2018 and that retroactive rate-making is generally to be avoided. FBC argues that the request by ICG should be denied.[286]

Panel Determination

The Panel approves the changes to FBC's transmission and ancillary services as applied for.

ICG's request to apply the change to RS 109 retroactively to January 1, 2018 is denied. The BCUC, as a matter of principle, does not engage in retroactive ratemaking and the Panel finds no compelling reason to deviate from this principle in the current situation.

[286] FBC Reply Argument, p. 55.

5.0 Electric Tariff and General Terms and Conditions

FBC is proposing housekeeping and other amendments to its General Terms and Conditions (GT&Cs) and its rate schedules. The proposed amendments include the regrouping and reorganization of certain sections for easier referencing.[287]

FBC also seeks approval to remove Schedules 74 (Extensions), 80 (Charges for Connection or Reconnection of Service Transfer of Account, Testing of Meters and Various Custom Work), 81 (Radio-Off Advanced Meter Option), and 82 (Charges for Installation of New/Upgraded Services) within FBC's Rate Schedules into the GT&Cs section of the Electric Tariff to better reflect that these contributions and charges are not impacted by general rate increases.

5.1 Housekeeping and Other Amendments to GT&Cs

FBC describes the majority of its proposed changes to be minor housekeeping amendments and reordering of sections of its GT&Cs. These proposed changes are described in section 10 of the Application and shown in a blackline version in Appendix G to the Application. FBC's proposed amendments include numerous changes which are intended to update and clarify existing language and, where appropriate, bring commonality to analogous sections in FEI's GT&Cs.[288]

More substantive changes include updates and increased clarity regarding the criteria for Residential Service, partial Commercial use at Residential Premises and Commercial Service, and changes to FBC's Security Deposit Policy to align with FEI's current processes.

Additionally, FBC updated the contribution and fee amounts for Extensions and Standard Charges based on a jurisdictional and internal cost review, which are derived to reflect FBC's current operating costs and environment.[289] FBC's last update to its Standard Charges was during the 2009 COSA and RDA.

The following table sets out the current and updated contribution amounts to customer extensions: [290]

Table 27: Line Extension Credits

Customer Class	Current	Updated
Residential (RS 1, 2A, 3, 3 A)	$1,741	$2,634
Small Commercial (RS 20, 21)	$155 per kW	$279 per kW
Commercial (RS 30)	$65 per kW	$121 per kW
Lighting (RS 50 – Type I, Type II)	$19.04 per fixture	$28.15 per fixture
Irrigation (RS 60, 61)	$3,037	$3,543

[287] Exhibit B-1, pp. 119-120.
[288] Ibid., p. 119.
[289] Exhibit B-1, Section 10.5; Exhibit B-8, BCUC IR 109.2.
[290] Exhibit B-1, Table 10-2, p. 124; Appendix D.

FBC's minimum connection charges for overhead and underground services have also been updated with proposed changes to reflect current costs, with calculations derived in Appendix D of the Application: [291]

Table 28: New/Upgrade Services Charges

	Current	Proposed
Overhead – Single Phase		
200 Amps or Less	$533	$739
400 Amps	$937	Removed
Underground – Single Phase		
200 Amps or Less	$565	$804

FBC also calculates its connection charges which are updated to reflect its current costs, with calculations derived in Appendix D of the Application:[292]

Table 29: Connection Charges

	Current	Proposed
Meter connection, or manual reconnection[69] of a meter after disconnection for violation of General Terms and Conditions		
Performed during regular working hours	$100	$135
Performed during overtime hours	$132	$224
Performed during callout hours	$339	$462
Each additional meter connection for one customer at the same time at one location	$25	$34
Remote reconnection[70] of a meter after disconnection for violation of General Terms and Conditions	n/a	$13
Disconnection and reconnection of meter	$200	$271
Relocation of Service	$673	$902

Lastly, various miscellaneous charges are updated to reflect current FBC costs, all with calculations derived in Appendix D of the Application:[293]

[291] Exhibit B-1, Table 10-3, p. 124; Appendix D.
[292] Ibid., Table 10-4, p. 125.
[293] Ibid., Table 10-5, pp. 125-126.

Table 30: Miscellaneous Charges

Standard Charge Name			
Current	Proposed	Current	Proposed
Charge for Service	Account Setup or Transfer	$15	$13
Returned Cheque Service Charge	Return Payment Charge	$19	$13
Collection Charge	Collection Charge	$12	Removed
Meter Access Charge – Single Phase Remote Meter	Meter Access Charge – Single Phase Remote Meter	$152	$206
Meter Access Charge – Poly Phase Remote Meter	Meter Access Charge – Poly Phase Remote Meter	$310	$419
False Site Visit Charge	False Site Visit Charge	$182	$246
Meter Testing	Meter Test Charge	$25	$135
Temporary Drop Service	Temporary to Permanent Service Charge	$200	$267
Temporary Drop Service	Salvage of Temporary Service Charge	$200	$267

Positions of the Parties

Most interveners either did not comment on FBC's proposed amendments to its GT&Cs or suggested that the BCUC should approve them. BCOAPO and ICG made some specific comments to certain FBC proposed changes.

BCOAPO objects to FBC's proposal to reduce the charge for new service (account) set up and changes to existing accounts (i.e. moves) from $15 to $13, arguing the BCUC should direct FBC to implement separate charges for new accounts ($13) and account transfers ($8). BCOAPO submits that a major contributor to the $13 is the $5.25 for the Equifax credit check and ID validation, an activity which is only required for new customers and not for moves. FBC provided reasoning in response to BCOAPO IR 89.1 as to why there are not separate charges for new accounts versus moves; however, BCOAPO does not consider these reasons to be "particularly compelling."[294]

In reply, FBC reiterates that it does not separately track when the Account Setup or Transfer fee is applied for a new customer versus an existing customer and therefore continuing the Account Setup or Transfer fee as a single fee is the most reasonable approach based on the available information.[295]

ICG submits that FBC is charging customers, without approval of the BCUC, based on a 15 minute demand window and FBC's Electric Tariff should include a provision that requires it to charge customers on a 30 minute demand window. In the event FBC does not adopt a 30 minute demand window, then the BCUC should establish a process to consider this issue.[296]

FBC responds that the current metering interval used for billing is consistent with that used for other commercial customers and it "should not be changed solely in response to the request of a small number of

[294] BCOAPO Final Argument, pp. 88-89.
[295] FBC Reply Argument, p. 70.
[296] ICG Final Argument, pp. 19-20.

customers as represented by ICG." FBC further states it is not against a separate process to consider this issue, but the imposition of such a change should not be considered as part of this process, as ICG did not raise the issue either in its evidence or IRs to FBC and is now requesting that the BCUC make a determination which would affect a large number of customers without any evidence being placed on the record.[297]

Panel Determination

The Panel approves all of FBC's requested changes to its General Terms and Conditions, as shown in Appendix G and H to the Application.

The Panel also approves the removal of Schedules 74, 80, 81 and 82 within FBC's Rate Schedules from the Electric Tariff, as the charges contained in these schedules have been moved to the GT&C's section of the Tariff.

The Panel notes that as part of FBC's 2016 LTERP and DSM Plan application, FBC requested that Schedule 90 be rescinded. **The Panel approves this request.**

The Panel declines BCOAPO's request to direct FBC to separate the charges for new accounts and account transfers. The Panel finds that maintaining the single charge is reasonable, as FBC has stated it does not separately track when the Account Setup or Transfer fee is applied for a new customer requesting an account versus an existing customer requesting to transfer an account. Further, maintaining the existing treatment is consistent with FEI's currently approved tariff.

The Panel declines ICG's request that the Electric Tariff terms and conditions be revised to include provisions specifying a 30 minute demand window for metering demand. We note FBC's statement that the current metering interval used for billing is consistent with the interval used for FBC's other commercial customers. Given that the intervals are consistent amongst customers, the Panel finds the current approach to be reasonable. The Panel further notes that ICG did not raise this issue in IRs so there is no evidence in this proceeding pertaining to the 30 minute demand window.

5.2 Radio-Off AMI Option and Radio-Off Shortfall Deferral Account

In the Application, FBC proposes to recover its projected 2018 balance of $0.120 million in its AMI Radio-Off Shortfall Deferral Account over the five-year period 2019–2023, and then to revisit the read fee in its next RDA. FBC also requests approval for an increase in the Per-Read Fee from $18 to $25, in which $1.50 would be related to the recovery of the deferral account over 5 years.[298]

In response to IRs, FBC updated its actual and forecast costs for the manual reading of meters and proposes that a Per-Read Fee of $19.50 (instead of $25) would be appropriate. Although FBC expects the net costs and revenue to be approximately equal in the future, FBC submits that the Radio-Off Shortfall Deferral Account should continue to be utilized until the termination of the current Performance Based Ratemaking (PBR) Plan on

[297] FBC Reply Argument, p. 83.
[298] Exhibit B-1, p. 126.

December 31, 2019, where it proposes to cease recording the net costs and read fees as of December 31, 2019, and to amortize the balance of the deferral account over a five-year period from 2019 to 2023.[299]

FBC also seeks approval to remove the Pre-Commencement of Deployment Setup Fee contained in Schedule 81 (Radio-Off Advanced Meter Option), because the AMI Project deployment is complete and the fee is no longer relevant.[300]

Positions of the Parties

BCOAPO submits that the BCUC should accept FBC's proposed method of recovery from Radio-Off customers and amortize the deferral balance over five years. However, BCOAPO notes that a $1.50 increase in the Per-Read Fee is based on amortizing the deferral account balance over a five-year period and therefore the language used in the tariff should indicate that the $19.50 is only applicable until December 31, 2023 (assuming a January 1, 2019 implementation date) after which the fee would be $18.00.[301]

In reply, FBC submits it has no concerns with the recommendation to set out a termination date, provided that it is set as five years from the implementation of the new per-read fee to ensure that the balance in the Radio-Off Shortfall Deferral Account as at December 31, 2019 is fully recovered.[302]

Panel Determination

The Panel approves FBC's request to increase the per-read fee for the Radio-Off AMI option from $18 to $19.50 and to continue to record any additional shortfall in the Radio-Off Shortfall Deferral Account until December 31, 2019, commensurate with the end of the current PBR term. The Panel acknowledges that the increase in the per-read fee reflects the increased cost to manually read the meters. **Approval is also granted to FBC to amortize the balance in the Radio-Off Shortfall Deferral Account over a five-year period from 2019 to 2023. This deferral account shall be closed at the conclusion of the five year amortization period.**

In addition, the Panel approves FBC's proposal to remove the Pre-Commencement of Deployment Setup Fee contained in Schedule 81 (Radio-Off Advanced Meter Option), as this portion of the fee is no longer required.

5.3 Other Issues

In its final submission, KSCA raises or introduces a number of matters it has concerns over. Some issues such as net metering, municipal power sales, and low income and inter-jurisdictional utility issues are considered by FBC to be outside of the COSA and rate design process and therefore FBC acknowledges but does not address these issues in its reply argument.[303]

KSCA also raises an issue with regards to the stationing of a permanent full time line person in the Kaslo and Area D portion of the FBC service area.[304] In reply, FBC refers to an IR response in which it explains there is

[299] Exhibit B-8, BCUC IR 97, 98.
[300] Exhibit B-1, p. 126.
[301] BCOAPO Final Argument, pp. 85-86.
[302] FBC Reply Argument, p. 68.
[303] FBC Reply Argument, p. 81.
[304] KSCA Final Argument, pp. 2-3.

insufficient work in Kaslo to warrant a permanent PLT position. FBC further explains that the installation of the AMI system provides safety and operational tools that did not previously exist and therefore it now has the ability to perform certain functions which in the past required a technician to be on site.[305]

Additionally, KSCA requests the BCUC consider setting up a jointly dedicated billing ombudsperson hotline to assist customers with the "lack of service by the utilities concerning correction of billing errors." KSCA further asks the Panel to consider directing…

> …each utility to report on a quarterly basis the number of customers, by class, that are in arrears, the amount of those arrears by class, the number of claims by class that have arisen disputing those claims of arrears, the number of claims by class disputing any and all fees and charges, the number of customers by class who have been reimbursed for billing errors, and the amounts involved for which customers by class have been reimbursed, with or without interest.[306]

FBC submits it does not consider the request to be related to the COSA or RDA and argues it should not be a matter for the current process.[307]

Panel Determination

The Panel has considered these other issues raised by KSCA. We are satisfied that the issues pertaining to net metering will be addressed in the next rate design application when more information becomes available. Several other matters raised by KSCA, such as municipal power sale and inter-jurisdictional utilities issues, are not within the scope of this proceeding. The Panel is also satisfied with FBC's response that there is insufficient work in Kaslo to warrant a permanent PLT position and further notes that stationing a permanent full time line person with insufficient work will not only add additional costs to service the Kaslo area, it also does not encourage efficient use of utility expenditures. **With regard to KSCA's request to set up a jointly dedicated billing ombudsperson hotline to address certain residential billing matters, the Panel considers the request to be reasonable and therefore recommends that the BCUC consult with residential customers in all service areas of the province to determine whether a similar need is identified in other service areas. However, the Panel denies the request to direct each utility's quarterly reporting for customers in arrears.** The Panel considers that information filed in this proceeding is necessary for its decision making within the scope of the issues it must decide on. If only for interest, parties may obtain such detailed information through freedom of information requests.

6.0 Compliance Filing to the Decision

As a result of the Panel's determinations in this Decision, a number of adjustments are required to be made to customer classes' rates. Some of these changes, including transitioning to the flat rate from the RCR, increases to certain customer classes' Customer Charge, and wording changes to the RS 101 tariff, require phase-in periods which the Panel expects FBC to present in detail in a compliance filing to this Decision.

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305 Exhibit B-27, KSCA IR 2.4.5.iii.
306 KSCA Final Argument, p. 2.
307 FBC Reply Argument, p. 82.

FBC is directed to submit to the BCUC, for review by this Panel, a compliance filing containing all of the items directed in this Decision and a proposed implementation date(s) for the changes approved by this Decision. FBC must submit the compliance filing within 60 days of the date of this Decision. The Panel directs that the rate changes identified in this Decision in the various rate schedules be based on the FBC rates in effect in 2017 and be exclusive of any subsequent revenue requirement rate changes that have been approved or may be approved prior to the implementation of the changes in this Decision.

7.0 Summary of Directives

This summary is provided for the convenience of readers. In the event of any difference between the directions in this summary and those in the body of the decision, the wording in the decision shall prevail.

	Directive	**Page**
1.	The Panel declines to take the actions requested by KSCA regarding the classification of distribution costs.	15
2.	The Panel therefore declines to take the actions requested by ICG regarding RS 37 revenues.	17
3.	Because consistency between current and past COSA studies allows for easier comparisons to be made, the Panel declines to direct FBC to make the changes to the 2017 COSA Study requested by BCOAPO.	18
4.	The Panel denies BCOAPO's request regarding the functionalization and classification of DSM costs.	19
5.	The Panel therefore accepts FBC's approach presented in the COSA Study and declines KSCA's request to direct FBC to change to the 12 CP allocator.	20
6.	Based on the evidence in the proceeding and in consideration of the arguments made by the parties, the Panel finds the 2017 COSA Study results reasonable and accepts the 2017 COSA Study as the basis for FBC's rate rebalancing and rate design proposals.	21
7.	The Panel directs FBC to rebalance the Lighting customer class (RS 50) and the Large Commercial Transmission customer class (RS 31) as follows: rebalance RS 50 to achieve a revenue-to-cost ratio of 100 percent and allocate the resulting revenues to RS 31.	26
8.	Accordingly, we direct FBC to file with the BCUC a Cost of Service study by no later than December 31, 2020.	29
9.	The Panel approves FBC's proposals for rate changes to the fixed Customer and Demand Charges for all rate classes as outlined in the Application.	35
10.	The Panel also approves FBC's proposal to phase in the customer charge for residential customers.	36

11.	Therefore, the Panel directs FBC as part of its compliance filing to provide a proposal outlining a phase-in option of up to three years for those RS 21 customers that have been identified as having a bill impact greater than 10 percent as a result of changes to fixed charges.	36
12.	For the reasons set out below, the Panel approves FBC's Application to switch to a flat rate for residential customers and to phase in the flat rate over a 5-year period, consistent with the previously approved phase-in of the increased customer charge of $18.70 per month.	49
13.	The Panel rejects FBC's proposals to revise and re-open the optional residential TOU rate to all residential customers and revise all other non-residential TOU rates.	66
14.	The Panel accepts FBC's approach to investigating the implementation of an off-season TOU Irrigation and Drainage rate and directs FBC to report to the BCUC on any analysis it has conducted and the results of the investigation and consultation with Irrigation customers within 120 days of the date of this Decision.	70
15.	The Panel approves the removal of RS 03 from FBC's Electric Tariff.	70
16.	Given this approval and in consideration of maintaining revenue neutrality, the Panel approves a decrease to the RS 20 energy rate from $0.10195 per kWh to $0.10000 per kWh.	72
17.	The Panel therefore approves flattening the energy rate to replace the current declining block rate structure, resulting in an energy rate of $0.06875 per kWh for all consumption. The Panel directs that FBC phase in the energy rate in accordance with the Panel's decision in Section 4.1 regarding the Customer and Demand charges.	72–73
18.	The Panel approves updating the transformation discount from $0.53 per kW of Billing Demand to $0.32 per kW of Billing Demand.	73
19.	The Panel approves updating the RS 30 transformation discount from $2.676 per kVA of Billing Demand to $5.26 per kVA of Billing Demand. T	74
20.	The Panel therefore approves decreasing the energy rate from $0.05516 per kWh to $0.05367 per kWh.	74
21.	The Panel therefore approves decreasing the RS 40 energy rate from $0.05441 per kWh to $0.05388 per kWh and approves decreasing the RS 60 energy rate from $0.07259 per kWh to $0.07240 per kWh.	76
22.	The Panel approves the addition of a transformation discount for RS 40 customers that take delivery at Transmission voltage.	76
23.	For the reasons provided below, the Panel approves the Proposed Changes to the tariff for RS 101 and RS 102 as applied for by FBC.	83

24.	We therefore direct that FBC phase-in the rate impact of the Proposed Changes over three years and apply the phase-in period for all applicable customers taking service under RS 101.	83
25.	Additionally, the Panel recommends that the BCUC establish a proceeding to conduct a broader review of transmission rate harmonization, as discussed in greater detail below.	83
26.	Therefore, the Panel approves the Proposed Changes to RS 101 and RS 102, subject to the modifications set out below.	84
27.	For these reasons, the Panel dismisses ICG's claim that the Proposed Changes should be rejected because FBC customers relied on the tariff.	85
28.	For the foregoing reasons, the Panel recommends that the BCUC establish a proceeding to inquire into the broader issues of transmission rate harmonization, with the involvement of transmission owners and transmission customers in the Province.	88
29.	We therefore decline to take the actions requested by ICG as the issue raised by ICG is outside the scope of this proceeding.	88
30.	The Panel approves the changes to FBC's transmission and ancillary services as applied for.	90
31.	ICG's request to apply the change to RS 109 retroactively to January 1, 2018 is denied	90
32.	The Panel approves all of FBC's requested changes to its General Terms and Conditions, as shown in Appendix G and H to the Application.	94
33.	The Panel also approves the removal of Schedules 74, 80, 81 and 82 within FBC's Rate Schedules from the Electric Tariff, as the charges contained in these schedules have been moved to the GT&C's section of the Tariff.	94
34.	The Panel notes that as part of FBC's 2016 LTERP and DSM Plan application, FBC requested that Schedule 90 be rescinded. The Panel approves this request.	94
35.	The Panel declines BCOAPO's request to direct FBC to separate the charges for new accounts and account transfers.	94
36.	The Panel declines ICG's request that the Electric Tariff terms and conditions be revised to include provisions specifying a 30 minute demand window for metering demand.	94
37.	The Panel approves FBC's request to increase the per-read fee for the Radio-Off AMI option from $18 to $19.50 and to continue to record any additional shortfall in the Radio-Off Shortfall Deferral Account until December 31, 2019,	95
38.	Approval is also granted to FBC to amortize the balance in the Radio-Off Shortfall Deferral Account over a five-year period from 2019 to 2023. This deferral account shall be closed at the conclusion of the five year amortization period.	95

39.	In addition, the Panel approves FBC's proposal to remove the Pre-Commencement of Deployment Setup Fee contained in Schedule 81 (Radio-Off Advanced Meter Option), as this portion of the fee is no longer required.	95
40.	With regard to KSCA's request to set up a jointly dedicated billing ombudsperson hotline to address certain residential billing matters, the Panel considers the request to be reasonable and therefore recommends that the BCUC consult with residential customers in all service areas of the province to determine whether a similar need is identified in other service areas. However, the Panel denies the request to direct each utility's quarterly reporting for customers in arrears.	96
41.	FBC is directed to submit to the BCUC, for review by this Panel, a compliance filing containing all of the items directed in this Decision and a proposed implementation date(s) for the changes approved by this Decision. FBC must submit the compliance filing within 60 days of the date of this Decision. The Panel directs that the rate changes identified in this Decision in the various rate schedules be based on the FBC rates in effect in 2017 and be exclusive of any subsequent revenue requirement rate changes that have been approved or may be approved prior to the implementation of the changes in this Decision.	97

DATED at the City of Vancouver, in the Province of British Columbia, this 25th day of February 2019.

Original signed by:

D. A. Cote
Panel Chair / Commissioner

Original signed by:

R. I. Mason
Commissioner

Original signed by:

D. M. Morton
Commissioner

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Utilities Commission

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ORDER NUMBER
G-40-19

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
2017 Cost of Service Analysis and Rate Design Application

BEFORE:
D. A. Cote, Panel Chair
R. I. Mason, Commissioner
D. M. Morton, Commissioner

on February 25, 2019

ORDER

WHEREAS:

A. On December 22, 2017, FortisBC Inc. (FBC) filed an application with the British Columbia Utilities Commission (BCUC) seeking approvals, pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA), to adjust its rate design and terms and conditions of service (Application);

B. By Orders G-23-18, G-62-18, G-101-18 and G-180-18, the BCUC established the regulatory timetable for the review of the Application which included, among other things, a procedural conference, two rounds of BCUC and intervener information requests (IRs) on the Application, the filing of intervener evidence, one round of IRs on intervener evidence, and written final and reply arguments;

C. On November 9, 2018, subsequent to the filing of FBC and intervener final arguments, the BCUC received an email from Kaslo Senior Citizens Association Branch #81 (KSCA) stating that FBC has failed to comply with a directive in the FBC 2011 Residential Inclining Block Rate Decision and Order G-3-12 related to the filing of an in-depth analysis of FBC's full long-run marginal cost (LRMC). KSCA requested the BCUC to direct FBC to comply with Order G-3-12 and to address other issues raised in an intervener final argument;

D. On November 16, 2018, the BCUC sought submissions from FBC and interveners on the issues raised in KSCA's email and provided KSCA with the opportunity to respond to the submissions received;

E. By letter dated November 9, 2018, the BCUC stated that upon consideration of all parties' submissions and the existing evidentiary record in the proceeding, the BCUC considered there to be sufficient evidence on the record to render its decision on the approvals sought in the Application and therefore the BCUC declined to re-open the evidentiary record or seek additional submissions on the matters raised by KSCA; and

F. The BCUC has considered the evidence and arguments filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 58 to 61 of the UCA, for the reasons provided in the Decision issued concurrently with this order, the BCUC orders as follows:

1. The following rate design proposals for Rate Schedule (RS) 01 are approved:
   - To decrease the differential between the Residential Conservation Rate (RCR) Tier 1 and Tier 2 price over the course of five years such that at the beginning of year five the differential between the Tier 1 and Tier 2 price will be zero, resulting in a flat rate.
   - To adjust the Customer Charge over the course of five years such that at the beginning of year five the Customer Charge under RS 01 will be equal to the Customer Charge under RS 03A (Residential Exempt Rate for Farm Customers).
2. Removal of RS 03 (RCR Control Group) from the Electric Tariff is approved.
3. An increase in the monthly Customer Charge for RS 20 from $19.40 to $23.00 and a corresponding decrease in the energy rate for RS 20 from $0.10195 per kWh to $0.10000 per kWh are approved.
4. The following rate design proposals for RS 21 are approved:
   - An increase in the monthly Customer Charge from $16.48 to $54.00 and a flattening of the energy rate, resulting in an energy rate of $0.06875 per kWh for all consumption. FBC is directed as part of the compliance filing ordered in Directive 16 of this order to provide a proposal outlining a phase-in option of up to three years for those RS 21 customers that have been identified as having a bill impact greater than 10 percent as a result of changes to fixed charges.
   - An increase in the per-kVA Demand Charge from $7.72 to $10.22.
   - An update to the transformation discount from $0.53 per kW of Billing Demand to $0.32 per kW of Billing Demand.
5. A change to the RS 30 transformation discount from $2.676 per kVA of Billing Demand to $5.26 per kVA of Billing Demand is approved.
6. The following rate design proposals for RS 31 are approved:
   - An increase in the monthly Customer Charge from $3,116.03 to $3,195.00 and a decrease in the energy rate from $0.05516 per kWh to $0.05367 per kWh.
   - An increase in the per-kVA Power Supply Demand Charge from $2.77 to $3.45.
7. The following rate design proposals for RS 40 are approved:
   - An increase in the monthly Customer Charge from $2,645.03 to $4,522.46 and a decrease in the energy rate from $0.05441 per kWh to $0.05338 per kWh.
   - The addition of a discount for RS 40 customers that take delivery at Transmission voltage.

8. An increase in the Customer Charge for RS 60 from $20.06 per month to $22.09 per month and a decrease in the energy rate from $0.07259 per kWh to $0.07240 per kWh are approved.

9. FBC's request to revise and re-open the optional residential Time of Use (TOU) rate to all residential customers and to revise all other non-residential TOU rates is denied.

10. FBC is directed to investigate the implementation of an off-season TOU Irrigation and Drainage rate and to report to the BCUC on any analysis it has conducted and the results of the investigation and consultation with Irrigation customers within 120 days of the date of this order.

11. The following rate design proposals for Transmission Service Rates are approved:
    - Changes to the anti-pancaking language contained in RS 101 and RS 102 in order to prevent the possibility of zero dollar rates noted in those rate schedules being applied to wheeling transactions where no pancaking of rates is possible. FBC is directed to phase-in the rate impact of the changes to the anti-pancaking language contained in RS 101 over three years and is directed to apply the phase-in period to all applicable customers taking service under RS 101.
    - Updates to the Short-Term and Long-Term Firm and Non-Firm Wheeling rates for RS 101 and RS 102 with pricing as described in the Application.
    - Changes to the Ancillary Services (RS 103 to RS 109) as described in the Application.

12. The following proposals for the Electric Tariff and General Terms and Conditions are approved:
    - Amendments to FBC's General Terms and Conditions as provided in Appendices G and H of the Application and further amended in errata to the Application.
    - The movement of Schedules 74 (Extensions), 80 (Charges for Connection or Reconnection of Service Transfer of Account, Testing of Meters and Various Custom Work), 81 (Radio-Off Advanced Meter Option) and 82 (Charges for Installation of New/Upgraded Services) from the Electric Tariff Rate Schedules to the General Terms and Conditions section of the Electric Tariff.
    - The rescindment of Schedule 90.

13. FBC is approved to increase the per-read fee for the Radio-Off AMI option from $18 to $19.50 and to continue recording any additional shortfalls in the Radio-Off Shortfall Deferral Account until December 31, 2019, commensurate with the end of the current Performance Based Ratemaking (PBR) term. FBC is directed to amortize the balance in the Radio-Off Shortfall Deferral Account over a five-year period from 2019 to 2023. This deferral account shall be closed at the conclusion of the five-year amortization period.

14. FBC is directed to rebalance the Lighting customer class (RS 50) and the Large Commercial Transmission customer class (RS 31) as follows: rebalance RS 50 to achieve a revenue-to-cost ratio of 100 percent and allocate the resulting revenues to RS 31. FBC is directed to provide the results of the rebalancing of RS 50 and RS 31 and the associated impacts on the customer classes' rates as part of the compliance filing ordered in Directive 16, including all supporting calculations.

15. FBC is directed to file with the BCUC a Cost of Service Study by no later than December 31, 2020.

16. FBC is directed to submit to the BCUC, for review by this Panel, a compliance filing containing all of the items directed in this Decision and a proposed implementation date(s) for the changes approved by this Decision. FBC must submit the compliance filing within 60 days of the date of this Decision.

17. The rate changes identified above in the various rate schedules are based on the FBC rates in effect in 2017 and are exclusive of any subsequent revenue requirement rate changes that have been approved or may be approved prior to implementation of the changes above.

18. FBC is directed to comply with all directives stated in the Decision.

DATED at the City of Vancouver, in the Province of British Columbia, this 25th day of February 2019.

BY ORDER

Original signed by:

D. A. Cote
Commissioner

Clean Energy Act
[SBC 2010] Chapter 22

British Columbia's Energy Objectives[310]

Part 1 — British Columbia's Energy Objectives

British Columbia's energy objectives

2 The following comprise British Columbia's energy objectives:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;

(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Climate Change Accountability Act*;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use

[310] *Clean Energy Act*, SBC 2010, c. 22.

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

(k) to encourage economic development and the creation and retention of jobs;

(l) to foster the development of first nation and rural communities through th use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

(p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

FortisBC Inc.

2017 Cost of Service Analysis and Rate Design Application

APPROVALS SOUGHT

1. Approval of the following rate design proposals for RS 01:
    - To decrease the differential between the Tier 1 and Tier 2 price such that after a period of five years the differential between the Tier 1 and Tier 2 price will be zero, resulting in a flat rate.
    - To adjust the Customer Charge over the course of five years such that at the beginning of year five the Customer Charge under RS 01 will be equal to the Customer Charge under RS 03A (Residential Exempt Rate for Farm Customers).
    - To re-open the optional Time of Use rate for residential customers while also restructuring the rate as described in detail in section 8 of the Application.
2. Removal of RS 03 (RCR Control Group) from the Electric Tariff.
3. Approval of the following rate design proposal for RS 20:
    - An increase in the monthly Customer Charge from $19.40 to $23.00 and a corresponding decrease in the energy rate from $0.10195 per kWh to $0.10000 per kWh.
4. Approval of the following rate design proposals for RS 21:
    - An increase in the monthly Customer Charge from $16.48 to $54.00 and a flattening of the energy rates resulting in an energy rate of $0.06875/kWh for all consumption.
    - An increase in the per-kVA Demand Charge from $7.72 to $10.22.
    - An update to the transformation discount from $0.53 per kW of Billing Demand to $0.32 per kW of Billing Demand
5. Approval of a change to the RS 30 transformation discount from $2.676 per kVA of Billing Demand to $5.26 per kVA of Billing Demand.
6. Approval of the following rate design proposals for RS 31:
    - An increase in the monthly Customer Charge from $3,116.03 to $3195.00 and a decrease in the energy rates from $0.05516 per kWh to $0.05367 per kWh.
    - An increase in the per-kVA Power Supply Demand Charge from $2.77 to $3.45.
7. Approval of the following rate design proposals for RS 60:
    - An increase in the Customer charge from $20.06 per month to $22.09 per month and a decrease in the energy rates from $0.07259 per kWh to $0.07240 per kWh.
8. Approval to add a discount for RS 40 customers that take delivery at Transmission voltage.
9. Approval to increase the Customer Charge for RS 40 from $2,645.03 to $4,522.46 and to decrease the energy rates for RS 40 from $0.05441 per kWh to $0.05388 per kWh.
10. Approval of the revised structure of existing optional TOU rate schedules as described in the Application.
11. Approval of the following rate design proposals for Transmission Service Rates:

- Changes to the anti-pancaking language contained in RS 101 in order to prevent the possibility of zero dollar rates noted in those rate schedules being applied to wheeling transactions where no pancaking of rates is possible.
- Updates to the Short and Long-term Firm and Non-Firm Wheeling rate for RS 101 and RS 102 with pricing as described in the Application.
- Changes to the Ancillary Services (RS 103 to RS 109) as described in the Application.

12. Approval of the following proposals for the Electric Tariff:
    - Amendments to FBC's General Terms and Conditions as set out in the Application, with the exception that the per read fee for the Radio-Off AMI option (Section 18.4 of the FBC Tariff) be set at $19.50.
    - The removal of Schedules 74 (Extensions), 80 (Charges for Connection or Reconnection of Service Transfer of Account, Testing of Meters and Various Custom Work), 81 (Radio-Off Advanced Meter Option), and 82 (Charges for Installation of New/Upgraded Services).
    - Rebalancing of rates for RS 50 and RS 31 as described in the Application.

FortisBC Inc.
2017 Cost of Service Analysis and Rate Design Application

LIST OF ACRONYMS

This summary is provided for the convenience of readers. In the event of any difference between the directions in this summary and those in the body of the decision, the wording in the decision shall prevail.

Acronym	Description
kW	Kilowatt
2 CP	2 coincident peak
2009 RDA Decision	FortisBC Inc. 2009 Rate Design and Cost of Service Analysis Application
AMCS/RDOS	Anarchist Mountain Community Society and Regional District of Okanagan-Similkameen
AMI	Advanced Metering Infrastructure
Application	FortisBC Inc. filed its 2017 Cost of Service Analysis and Rate Design Application on December 22, 2017
BC Hydro	British Columbia Hydro and Power Authority
BCMEU	British Columbia Municipal Electrical Utilities
BCOAPO	British Columbia Old Age Pensioners Organization *et al.*
BCSEA-SCBC	BC Sustainable Energy Association and Sierra Club BC
BCUC	British Columbia Utilities Commission
CEA	*Clean Energy Act*
Celgar	Zellstoff Celgar
CLP	Climate Leadership Plan
COSA	Cost of Service Analysis
DCE	Deferred Capital Expenditure
DSM	Demand-Side Management
EES	EES Consulting Inc.
FBC	FortisBC Inc.
FEI	FortisBC Energy Inc.
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas

GT&Cs	General Terms and Conditions
ICG	Industrial Consumers Group
IRG	Irrigation Ratepayers GrouP
IRs	Information Requests
KSCA	Kaslo Senior Citizens Association, Branch 81
kVA	Kilo-volt-ampere
kWh	Kilowatt-hour
LRMC	Long-run marginal cost
MSS	Minimum System Study
OEB	Ontario Energy Board
PBR	Performance Based Ratemaking
R/C	Revenue to cost
RCR	Residential Conservation Rate
RDA	Rate Design Application
Resolution	Resolution Electric Limited
RIB	Residential Inclining Block
RoR	Range of reasonableness
RS	Rate Schedules
the CEC	Commercial Energy Consumers Association of BC
TOU	Time of Use
UCA	*Utilities Commission Act*

FortisBC Inc.
2017 Cost of Service Analysis and Rate Design Application

LIST OF EXHIBITS

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated January 8, 2018 – Appointing the Panel for the review of the FortisBC Inc. 2017 Cost of Service Analysis and Rate Design Application
A-2	Letter dated January 25, 2018 – Establishing a Regulatory Timetable and Public Notice
A-3	Letter dated February 26, 2018 – Procedural Conference Information
A-4	Letter dated March 16, 2018 – Commission Order G-62-18 establishing a regulatory timetable with reasons
A-5	Letter dated March 29, 2018 – Submitting Commission Information Request No. 1 to FBC
A-6	Letter dated April 16, 2018 – Commission request for comments regarding requested Regulatory Timetable Amendments
A-7	Letter dated April 20, 2018 – Village of Kaslo Information Request No. 1 Late Filing
A-8	Letter dated May 7, 2018 – Request for Submissions and Suspension of Regulatory Timetable
A-9	Letter dated May 16, 2018 – Comment regarding Submissions on Further Process
A-10	Letter dated May 17, 2018 – Response to comments in Exhibit C4-7 regarding unanswered information requests
A-11	Letter dated May 30, 2018 – BCUC Order G-101-18 establishing a regulatory timetable with reasons
A-12	Letter dated June 18, 2018 – BCUC Information Request No. 2 to FBC
A-13	Letter dated August 20, 2018 – BCUC Information Request No. 1 to AMCS/RDOS
A-14	Letter dated August 20, 2018 – BCUC Information Request No. 1 to BCSEA-SCBC
A-15	Letter dated August 20, 2018 – BCUC Information Request No. 1 to BC Hydro
A-16	Letter dated August 20, 2018 – BCUC Information Request No. 1 to ICG

A-17	Letter dated September 10, 2018 – Submission Request on Further Process
A-18	Letter dated September 25, 2018 – Order G-180-18 continuing the Regulatory Timetable with Reasons for Decision
A-19	Letter dated November 16, 2018 – Request for Submissions
A-20	Letter dated November 29, 2018 – BCUC Response to Submissions on Further Process

APPLICANT DOCUMENTS

B-1	**FORTISBC INC. (FBC)** Letter dated December 22, 2017 - 2017 Cost of Service Analysis and Rate Design Application
B-1-1	Letter dated February 27, 2018 – FBC Submitting Errata to the Application
B-1-2	Letter dated March 19, 2018 – FBC submitting Kelowna February 13, 2018 Public Information Session Presentation
B-1-3	Letter dated March 19, 2018 – FBC submitting Castlegar February 16, 2018 Public Information Session Presentation
B-1-4	Letter dated May 8, 2018 – FBC Submitting Errata to the Application
B-1-5	Letter dated July 10, 2018 – FBC Submitting Errata to the Application
B-2	Letter dated March 2, 2018 – FBC Submitting Cost of Service Allocation (COSA) Model
B-3	Submitted at Procedural Conference March 6, 2018 – FBC Submitting List of Proposed Timetable dates
B-4	Letter dated March 9, 2018 – FBC Submitting Clarification of Five Year Residential Conservation Rate (RCR) Phase Out Period
B-5	Letter dated April 10, 2018 – FBC Submitting Request to Amend Regulatory Timetable
B-6	Letter dated April 18, 2018 – FBC Submitting Comments on Timetable
B-7	Letter dated April 24, 2018 – FBC Submitting Reply Comments on Timetable
B-8	Letter dated May 8, 2018 – FBC Submitting Responses to BCUC IR No. 1
B-8-1	Letter dated June 5, 2018 – FBC Submitting Addendum to Response to BCUC IR No. 1 Question 90.2
B-8-2	Letter dated July 10, 2018 – FBC Submitting Errata to BCUC IR1.48.2 and 1.90.2
B-8-3	Letter dated July 17, 2018 – FBC Submitting BCUC IR1 Attachment 88.9 Erratum
B-9	**CONFIDENTIAL** Letter dated May 8, 2018 – FBC Submitting Confidential Responses to BCUC IR No. 1, 12.2 and 12.3 – Cover Letter only on web
B-9-1	**CONFIDENTIAL** Letter dated October 23, 2018 – FBC Submitting Errata to Confidential Responses to BCUC IR No. 1, 12.2 – Cover Letter only on web
B-10	Letter dated May 8, 2018 – FBC Submitting Responses to AMC-RDOS IR No. 1

B-11	Letter dated May 8, 2018 – FBC Submitting Responses to BCOAPO IR No. 1
B-12	Letter dated May 8, 2018 – FBC Submitting Responses to BCSEA IR No. 1
B-12-1	Letter dated May 17, 2018 – FBC Submitting Errata to Response to BCSEA IR No. 1.22.5
B-13	Letter dated May 8, 2018 – FBC Submitting Responses to CEC IR No. 1
B-14	Letter dated May 8, 2018 – FBC Submitting Responses to Gabana IR No. 1
B-15	Letter dated May 8, 2018 – FBC Submitting Responses to ICG IR No. 1
B-15-1	Letter dated July 10, 2018 – FBC Submitting Errata to ICG IR 1.11.13
B-16	Letter dated May 8, 2018 – FBC Submitting Responses to IRG IR No. 1
B-16-1	Letter dated July 10, 2018 – FBC Submitting Errata to IRG IR 1.5.1
B-17	Letter dated May 8, 2018 – FBC Submitting Responses to KSCA IR No. 1
B-17-1	Letter dated May 17, 2018 – FBC Submitting Revised Response to IR 1.15.1
B-17-2	Letter dated July 10, 2018 – FBC Submitting Errata to KSCA IR 1.2.1.1
B-18	Letter dated May 8, 2018 – FBC Submitting Responses to Resolution IR No. 1
B-19	Letter dated May 8, 2018 – FBC Submitting Responses to VOK IR No. 1
B-20	Letter dated May 24, 2018 – FBC Submitting Reply Comments on Procedure
B-21	Letter dated July 10, 2018 – FBC Submitting Response to BCUC IR No.2
B-22	Letter dated July 10, 2018 – FBC Submitting Response to AMC-RDOS IR No.2
B-23	Letter dated July 10, 2018 – FBC Submitting Response to BCOAPO IR No.2
B-24	Letter dated July 10, 2018 – FBC Submitting Response to BCSEA IR No.2
B-25	Letter dated July 10, 2018 – FBC Submitting Response to CEC IR No.2
B-26	Letter dated July 10, 2018 – FBC Submitting Response to ICG IR No.2
B-27	Letter dated July 10, 2018 – FBC Submitting Response to KSCA IR No.2
B-28	Letter dated July 10, 2018 – FBC Submitting Response to IRG IR No.2

B-29	Letter dated August 20, 2018 – FBC Information Request No. 1 to AMCS-RDOS
B-30	Letter dated August 20, 2018 – FBC Information Request No. 1 to BC Hydro
B-31	Letter dated August 20, 2018 – FBC Information Request No. 1 to BCSEA-SCBC
B-32	Letter dated August 20, 2018 – FBC Information Request No. 1 to ICG
B-33	Letter dated August 20, 2018 – FBC Information Request No. 1 to KSCA
B-34	Letter dated August 20, 2018 – FBC Information Request No. 1 to Resolution
B-35	Letter dated September 12, 2018 – FBC will not file Rebuttal Evidence
B-36	Letter dated September 17, 2018 – FBC Submission on Further Process
B-37	Letter dated September 19, 2018 – FBC Reply to Intervener Submissions on Further Process

INTERVENER DOCUMENTS

C1-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** letter dated January 31, 2018 – Request to Intervene by Fred James
C1-2	Letter dated March 2, 2018 – BCH Procedural Conference Submission
C1-3	Letter dated July 31, 2018 – BCH Submitting Evidence
C1-4	Letter dated September 10, 2018 – BCH Submitting Response to BCUC IR No. 1
C1-5	Letter dated September 10, 2018 – BCH Submitting Response to Intervener IR No. 1
C1-6	Letter dated September 17, 2018 – BCH Submission on Further Process and Revision to BCH Response to CEC Information Request No. 1.2.3
C2-1	**BC SUSTAINABLE ENERGY ASSOCIATION AND SIERRA CLUB BC (BCSEA)** Letter dated February 15, 2018 - Request to Intervene by William Andrews and Thomas Hackney
C2-2	Letter dated March 28, 2018 – BCSEA Submitting IR No. 1 to FBC
C2-3	Letter dated April 18, 2018 – BCSEA Submitting Comments on Procedure
C2-4	Letter dated May 18, 2018 – BCSEA Submitting Comments on Procedure
C2-5	Letter dated June 18, 2018 – BCSEA Information Request No. 2 to FBC
C2-6	Letter dated July 31, 2018 – BCSEA Submitting Evidence
C2-7	Letter dated August 20, 2018 – BCSEA Submitting IR No. 1 to AMCS RDOS
C2-8	Letter dated September 10, 2018 – BCSEA Submitting Response to AMCS-RDOS IR No. 1
C2-9	Letter dated September 10, 2018 – BCSEA Submitting Response to BCOAPO IR No. 1
C2-10	Letter dated September 10, 2018 – BCSEA Submitting Response to BCUC IR No. 1
C2-11	Letter dated September 10, 2018 – BCSEA Submitting Response to CEC IR No. 1
C2-12	Letter dated September 10, 2018 – BCSEA Submitting Response to FBC IR No. 1
C2-13	Letter dated September 14, 2018 – BCSEA Submission on Further Process
C3-1	**ANARCHIST MOUNTAIN COMMUNITY SOCIETY AND REGIONAL DISTRICT OF OKANAGAN-SIMILKMEEN (AMCS RDOS)** Letter dated February 19, 2018 - Request to Intervene by David Bursey
C3-2	Letter dated March 29, 2018 – Submitting AMCS RDOS Information Request No. 1 to FBC

C3-3	Letter dated April 12, 2018 – AMCS RDOS Submitting Response to FBC's Request to Amend the Regulatory Timetable
C3-4	Letter dated April 19, 2018 – AMCS RDOS Submitting Comments on Timetable
C3-5	Letter dated May 17, 2018 – AMCS RDOS Submitting Comments on Further Process
C3-6	Letter dated June 18, 2018 – AMCS RDOS Submitting Information Request No. 2 to FBC
C3-7	Letter dated July 31, 2018 – AMCS RDOS Submitting Evidence
C3-8	Letter dated August 20, 2018 - AMCS RDOS Submitting Information Request No. 1 to BCSEA
C3-9	Letter dated September 10, 2018 – AMCS RDOS Submitting Response to BCUC IR No. 1
C3-10	Letter dated September 10, 2018 – AMCS RDOS Submitting Response to FBC IR No. 1
C3-11	Letter dated September 10, 2018 – AMCS RDOS Submitting Response to BCOAPO IR No. 1
C3-12	Letter dated September 10, 2018 – AMCS RDOS Submitting Response to CEC IR No. 1
C3-13	Letter dated September 10, 2018 – AMCS RDOS Submitting Response to BCSEA-SCBC IR No. 1
C3-14	Letter dated September 10, 2018 – AMCS RDOS Submitting Response to KSCA81 IR No. 1
C3-15	Letter dated September 17, 2018 – AMCS RDOS Submission on Further Process
C4-1	**KASLO SENIOR CITIZENS ASSOCIATION - BRANCH NO.81 (KSCA81)** Letter dated February 21, 2018 - Request to Intervene by Andy Shadrack
C4-2	Letter dated March 2, 2018 – KSCA81 Procedural Conference Submission
C4-3	Letter dated March 9, 2018 – KSCA81 Procedural Submission
C4-4	Letter dated March 27, 2018 – Submitting KSCA81 Information Request No. 1 to FBC
C4-5	Letter dated April 10, 2018 – KSCA81 Submitting Request to Amend Regulatory Timetable
C4-6	Letter dated April 24, 2018 – KSCA81 Submitting Reply Comments on Timetable
C4-7	Letter dated May 11, 2018 – KSCA81 Submitting Request under Rule 14.05 of the Rules of Practice and Procedure Regarding FBC Responses to IR 1
C4-8	Letter dated May 18, 2018 – KSCA81 Submitting Comments on Procedure

C4-9	Letter dated April 19, 2018 – KSCA81 Submitting Background Material on Information Request Nos. 1 and 2
C4-10	Letter dated June 18, 2018 – KSCA81 Submitting Information Request No. 2 to FBC with attachments
C4-11	Letter dated July 31, 2018 – KSCA81 Submitting Evidence
C4-12	Letter dated August 20, 2018 - KSCA81 Submitting Information Request No. 1 to AMCS-RDOS
C4-13	Letter dated September 6, 2018 - KSCA81 Submitting Response to CEC Information Request No. 1 on KSCA81 Evidence
C4-14	Letter dated September 8, 2018 - KSCA81 Submitting Response to FBC Information Request No. 1 on KSCA81 Evidence
C4-15	Letter dated September 17, 2018 – KSCA81 Submission on Further Process
C5-1	**VILLAGE OF KASLO (VOK)** Letter dated February 21, 2018 - Request to Intervene by Neil Smith
C5-2	Letter dated March 2, 2018 – VOK Procedural Conference Submission
C5-3	Letter dated April 16, 2018 – VOK Submitting Late IR No. 1 to FBC
C5-4	Letter dated May 18, 2018 – VOK Submitting Request to Review IR Response
C6-1	**NELSON HYDRO FOR THE BCMEU (BCMEU)** Letter dated February 22, 2018 - Request to Intervene Marg Craig
C6-2	Letter dated March 2, 2018 – BCMEU Procedural Conference Submission
C6-3	Letter dated May 18, 2018 – BCMEU Submitting Comments on Procedure
C6-4	Letter dated September 17, 2018 – BCMEU Submission on Further Process
C7-1	**GABANA, NORMAN (GABANA)** Letter dated February 22, 2018 - Request to Intervene
C7-2	Letter dated March 27, 2018 – Gabana Submitting IR No. 1 to FBC
C8-1	**IRRIGATION RATEPAYERS GROUP (IRG)** Letter dated February 22, 2018 - Request to Intervene by Fred Weisberg
C8-2	Letter dated March 29, 2018 – IRG Submitting IR No. 1 to FBC
C8-3	Letter dated April 19, 2018 – IRG Submitting Comments on Timetable

C8-4	Letter dated May 18, 2018 – IRG Submitting Comments on Procedure
C8-5	Letter dated June 18, 2018 – IRG Submitting Information Request No. 2 to FBC
C8-6	Letter dated September 18, 2018 – IRG Submission on Further Process
C9-1	**RESOLUTION ELECTRIC LTD (REL)** Letter dated February 22, 2018 - Request to Intervene by John Cawley
C9-2	Letter dated March 29, 2018 – Resolution Submitting IR No. 1 to FBC
C9-3	Letter dated April 18, 2018 – Resolution Submitting Comments on Timetable
C9-4	Letter dated July 31, 2018 – Resolution Submitting Evidence
C9-5	Letter dated September 7, 2018 – Resolution Submitting Responses to FBC IR No. 1
C9-6	Letter dated September 7, 2018 – Resolution Submitting Responses to CEC IR No. 1
C10-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** Letter dated February 23, 2018 - Request to Intervene by Christopher Weafer
C10-2	Letter dated March 2, 2018 – CEC Procedural Conference Submission
C10-3	Letter dated March 29, 2018 – CEC Submitting IR No. 1 to FBC
C10-4	Letter dated April 18, 2018 – CEC Submitting Comments on Timetable
C10-5	Letter dated May 18, 2018 – CEC Submitting Comments on Procedure
C10-6	Letter dated June18, 2018 – CEC Submitting Information Request No. 2 to FBC
C10-7	Letter dated August 20, 2018 – CEC Information Request No. 1 to BCSEA-SCBC
C10-8	Letter dated August 20, 2018 – CEC Information Request No. 1 to AMCS-RDOS
C10-9	Letter dated August 20, 2018 – CEC Information Request No. 1 to Resolution
C10-10	Letter dated August 20, 2018 – CEC Information Request No. 1 to BC Hydro
C10-11	Letter dated August 20, 2018 – CEC Information Request No. 1 to Kaslo
C10-12	Letter dated August 20, 2018 – CEC Information Request No. 1 to ICG
C10-13	Letter dated September 17, 2018 – CEC Submission on Further Process

C11-1 **ZELLSTOFF CELGAR (CELGAR)** Letter dated February 15, 2018 - Request to Intervene by Robert Hobbs

C12-1 **INDUSTRIAL CUSTOMERS GROUP (ICG)** Letter dated February 15, 2018 - Request to Intervene by Robert Hobbs

C12-2 Letter dated March 29, 2018 – Submitting ICG Information Request No. 1 to FBC

C12-3 Letter dated April 18, 2018 – ICG Submitting Comments on Timetable

C12-4 Letter dated May 18, 2018 – ICG Submitting Comments on Procedure

C12-5 Letter dated June 18, 2018 – ICG Information Request No. 2 to FBC

C12-6 Letter dated July 31, 2018 – ICG Submitting Evidence

C12-7 Letter dated August 20, 2018 – ICG Submitting Information Request No. 1 to BCH

C12-8 Letter dated September 10, 2018 – ICG Submitting Responses to BCUC IR No. 1

C12-9 Letter dated September 10, 2018 – ICG Submitting Responses to CEC IR No. 1

C12-10 Letter dated September 10, 2018 – ICG Submitting Responses to FBC IR No. 1

C12-11 Letter dated September 14, 2018 – ICG Submission on Further Process

C12-12 Letter dated October 23, 2018 – ICG Submitting Confidential Undertaking for Robert Hobbs and Elroy Switlishoff

C13-1 **BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION ET AL (BCOAPO) –** Letter dated March 2, 2018 – Request to intervene by Leigha Worth

C13-2 Letter dated March 29, 2018 – BCOAPO Submitting IR No. 1 to FBC

C13-3 Letter dated May 18, 2018 – BCOAPO Submitting Comments on Procedure

C13-4 Letter dated June 18, 2018 – BCOAPO Late Information Request No. 2 to FBC

C13-5 Letter dated August 20, 2018 – BCOAPO Information Request No. 1 to BCSEA

C13-6 Letter dated August 20, 2018 – BCOAPO Information Request No. 1 to AMCS-RDOS

C13-7 Letter dated August 20, 2018 – BCOAPO Information Request No. 1 to BCH

C13-8 Letter dated September 17, 2018 – BCOAPO Submission on Further Process

INTERESTED PARTY DOCUMENTS

D-1

LETTERS OF COMMENT

E-1	Wyngaard, Jon - Letter of Comment dated January 25, 2018
E-1-1	Wyngaard, Jon - Letter of Comment dated January 30, 2018
E-2	Wishneski, R - Letter of Comment dated February 8, 2018
E-3	Doell, Larry – Letter of Comment dated February 10, 2018
E-4	McGinnigle J, – Letter of Comment dated February 17, 2018
E-5	Hutter, H – Letter of Comment dated February 22, 2018
E-6	Kennedy, M – Letter of Comment dated February 28, 2018
E-7	DeBiasio, D – Letter of Comment dated March 2, 2018
E-8	Braun, V – Letter of Comment dated March 13, 2018
E-9	Stetski, W – Letter of Comment dated March 1, 2018
E-10	Roberts, S – Letter of Comment dated March 27, 2018
E-11	Louise, L – Letter of Comment dated April 3, 2018 – Removed from Web only
E-11-1	Louise, L – Letter of Comment dated April 12, 2018 – Replacement to Exhibit E-11
E-12	Mccormick, C – Letter of Comment dated April 9, 2018
E-13	Regional District of Central Kootenay – Letter of Comment dated March 28, 2018
E-14	McCormick, D – Letter of Comment dated April 9, 2018
E-15	Gilmore, J – Letter of Comment dated April 11, 2018
E-16	Symmes, L – Letter of Comment dated April 12, 2018
E-17	Beix, E – Letter of Comment dated April 12, 2018
E-18	O'Keefe – Letter of Comment dated April 14, 2018
E-19	Kubara, S – Letter of Comment dated April 28, 2018

E-20	Kaslo Food Hub – Letter of Comment dated May 8, 2018
E-21	Dallyn, M-Rolls, W – Letter of Comment dated April 19, 2018
E-22	Sherwood, R and D – Letter of Comment dated July 27, 2018
E-23	Louise, L – Letter of Comment dated August 29, 2018