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December 22, 2017

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

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

Dear Mr. Wruck:

Re: FortisBC Inc. (FBC)

2017 Cost of Service Analysis and Rate Design Application

Pursuant to sections 58 to 61 of the *Utilities Commission Act*, FBC files the attached 2017 Rate Design Application.

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

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties to FBC's PBR Annual Reviews
Pre-Application Rate Design Information Sessions and Workshop Participants and Stakeholders

FortisBC Inc.

2017 Cost of Service Analysis and Rate Design Application

Volume 1 - Application

December 22, 2017

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1. EXECUTIVE SUMMARY

1.1 INTRODUCTION

In this 2017 Rate Design Application (Application or 2017 RDA[1]), FortisBC Inc. (FBC or the Company) reviews its existing rate design and proposes a limited number of changes to rates. The proposed changes are in keeping with accepted rate design principles and FBC brings them forward in response to changes in the needs and circumstances of certain rate classes.

The Application is the result of a comprehensive review of FBC's rates and rate-related policies, as well as a cost of service analysis (COSA).

FBC retained EES Consulting Inc. (EES Consulting), a third party expert in public utility rate design matters, to develop the COSA and review and assist in rate design for FBC. As discussed in more detail in its report (the EES COSA Report), EES Consulting completed the COSA for this Application following standard utility practice and using inputs and allocation methodologies substantially the same as past practice for the utility. The results of the EES COSA are used to ensure that proposed rates are fair, equitable and not unduly discriminatory. The COSA results show the extent to which each rate schedule (RS when referring to a specific rate schedule) recovers its allocated cost of service.

FBC further conducted a review of its rate schedules considering rate design principles, government policy, the statutory regime, stakeholder comments, and analysis of other data including load characteristics, as well as challenges facing electric utilities from the increasing adoption of emerging alternative technologies. As part of its rate design review, FBC considered alternative rate structures for certain classes, the potential adoption of optional conservation or load management rates, the appropriate level of fixed versus variable charges, intra-class rate economics, the appropriate calculation of demand charges, wheeling rates, and various terms and conditions of service.

As outlined in this Application, the COSA and FBC's rate design review considered each of the rate schedules associated with Residential, Commercial and Wholesale customers; optional rate structures; transmission access and wheeling rates; and FBC's General Terms and Conditions (sometimes abbreviated in this Application as GT&Cs).

FBC has not addressed several rate-related items in the current Application where those items (a) have been recently approved by the Commission (namely, Stand-by and Maintenance Rates [RS 37]), or (b) are the subject of a separate application (namely, Electric Vehicle Charging Rate and Lighting Rates for LED fixtures), or (c) are already the subject of their own processes running concurrently before the Commission (FBC's Community Solar Pilot Project and related rates and FBC's Self-Generation Policies).

[1] The abbreviation "RDA" is sometimes also used in the body of the Application to refer to a "rate design application". The term "2017 RDA" is used specifically in relation to the Application.

With respect to the Company's Net Metering (NM) Program that was the subject of a recent Commission decision and in certain limited respects is currently being examined in a reconsideration,[2] the Company is not seeking to make further changes to the basic structure of the NM rate (RS 95) as part of the 2017 RDA. However, for completeness, FBC examined the residential NM participants in isolation within the COSA and in light of current trends toward rates for distributed generation. The data indicate that there is a difference in the extent to which costs are recovered from this sub-group of customers as compared to customers that are not part of the NM Program. Therefore, an alternative residential rate structure for NM participants was examined during the preparation of the Application, though it has not been proposed for implementation at this time. Further discussion of this topic is included in Section 3.6 of the Application.

A more detailed summary of each aspect of the proposed rate design is provided in the sections below.

[2] FortisBC Inc. Application for Reconsideration and Variance of Order G-199-16 FBC Net Metering Program Tariff Update Decision ~ Phase 2 ~ Project No.3698875.

1.2 THE APPLICATION

The Application is organized into the following sections, which are discussed briefly in this Executive Summary:

Section	Topic
2	Application and Approvals Sought
3	Context and Consideration for Cost of Service Analysis and Rate Design
4	Public Consultation
5	Cost of Service and Rate Rebalancing
6	Rate Design
7	Transmission Services
8	Optional Time of Use Rates
9	Other Rate Schedules
10	General Terms and Conditions

1.3 CONTEXT AND CONSIDERATION FOR COST OF SERVICE ANALYSIS AND RATE DESIGN

The COSA and rate design processes are completed in consideration of a variety of factors, both internal to the operation of FBC, and in the environment in which the Company operates. These considerations, such as applicable government policies, laws and regulations, previous rate design activities, principles and objectives of rate design and industry trends, are discussed in the Application and are summarized below.

1.3.1 Legal Context

FBC files the 2017 RDA for approval by the Commission under sections 58, 59, 60 and 61 of the *Utilities Commission Act*, RSBC 1996, Chapter 473 (the UCA).

- Section 58 of the UCA addresses the situations in which the Commission may order amendment of rate schedules.
- Section 59 of the UCA addresses the issue of rate discrimination. It states that a public utility must not make, demand or receive “an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it”.
- Section 60 of the UCA provides broad rate-setting guidelines for the Commission to consider when determining rates.
- Section 61 of the UCA requires a public utility to file rate schedules with the Commission, to receive the Commission’s approval before rescinding or amending a schedule and to charge only those rates that are in accordance with the filed schedules.

1.3.2 Rate Design Principles and Government Policy

As described in Section 3.2 of the Application, FBC's rate design review and proposals are also guided by the widely accepted rate design principles identified by Dr. Bonbright in his seminal work, *Principles of Public Utility Rates*. The principles adopted by FBC, as previously summarized by the Commission, are as follows:[3]

- 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 impacts should be managed).
- Principle 7: Revenue stability.
- Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained).

FBC does not generally apply the eight principles above in any priority or with any particular weighting. However, the Company does consider that the principle of cost causation (as articulated in Principle 2 but also considered in various other principles) represents an important foundation upon which cost allocation and rate design should rest. Rate design is a complex balancing process, as it frequently requires the application of multiple, and sometimes conflicting, principles and the consideration of viewpoints from various stakeholders. In addition, different rate design principles may have varying levels of importance in different contexts. FBC, therefore, applies its experience and judgment to consider and balance the most relevant principles in a given context when identifying rate design issues and proposing rate design solutions. Rate design should strive to strike a balance among competing rate design principles based on specific characteristics of customers in each rate schedule.

In addition to the eight Bonbright rate design principles, FBC considers government policy as reflected in the legislation and regulations implementing those policies, and in published government energy policy documents. Section 3.2 discusses how the Application incorporates these factors and considerations.

[3] Appendix A of Order G-45-11 in the BC Hydro Residential Inclining Block Re-Pricing Application.

1.3.3 Background and Regulatory History of FBC Rate Design

Section 3.3 of the Application provides a discussion of the recent regulatory processes and Commission decisions that inform the 2017 RDA. FBC and its predecessors filed three major rate design applications with the Commission in 1983, 1997 and 2009. The most recent COSA and RDA was filed in 2009 (2009 COSA and RDA). In addition, a number of rate-related processes have either recently concluded or are being considered concurrently by the Commission; to the extent that Commission decisions will impact rate structures addressed in the 2017 RDA, those decisions also inform the 2017 RDA's content. Section 3.3 includes a discussion of the 2009 COSA and RDA proceeding, the 2011 Residential Inclining Block Rate Design proceeding, the 2013 Stepped and Stand-by Rates for Transmission (Voltage) Customers proceeding, the 2015 Self-Generation Policy proceeding (Stage I), and the 2016 Net Metering Program Tariff Update proceeding.

1.3.4 Additional Context for the 2017 Application

In addition to the matters set out in Sections 1.3.1-1.3.2 above, with this Application FBC seeks to address emerging trends in utility operations and rate design. A number of the changes in the use of the utility system discussed in this Application are "emerging" and are not currently resulting in operational issues or significant rate pressures at this time. While the Company is not proposing to introduce any new rates specifically designed to address the emerging uses of the utility system in this Application, as the particular situations have not sufficiently developed, it may be necessary to do so in the future. The focus of the discussion in Section 3.5 of the Application is on how rates can be designed in the future to consider the increasing interconnection of customer-owned generation, which is generally encapsulated in the Company's discussion of alternate rates for NM customers (Section 3.6).

1.4 *PUBLIC CONSULTATION*

Section 4 of the Application discusses the consultation that FBC undertook prior to filing the Application. FBC conducted a stakeholder engagement process consisting of information sessions, stakeholder workshops and outreach to specific customer groups with respect to items applicable to that customer group, and provided opportunities to provide online feedback. FBC's stakeholder engagement process informed customers and other stakeholders about COSA and rate design principles, and in turn provided information about possible rate alternatives and related impacts. Stakeholders and customary intervener groups were provided with the opportunity to bring rate design issues forward for FBC's consideration. FBC considered the comments and questions of stakeholders in selecting and preparing the rate design proposals set out in this Application.

1.5 *COST OF SERVICE AND RATE REBALANCING*

A COSA is one of the major inputs that is used in evaluating rates options for FBC. The COSA takes the revenue requirement established for the utility and allocates costs across the various customer classes, with the results used to ensure that proposed rates are fair, equitable, and not unduly discriminatory. EES Consulting worked with FBC staff in establishing the COSA methodology and reviewing existing rate designs, making recommendations for changes where warranted, and constructing the COSA model using data provided by FBC.

The FBC COSA was conducted in accordance with standard utility practice to allocate FBC's costs to each of FBC's customer classes. The costs and revenues used in the COSA reflect FBC's forecast 2017 test year. The allocated costs by rate schedule are compared to the revenue collected by rate schedule to calculate the respective revenue to cost (R/C) ratio. The R/C ratio shows whether the rates charged pursuant to each rate schedule adequately recover the allocated cost of service.[4] The resulting R/C ratios are, with two exceptions, within the 95 percent to 105 percent range of reasonableness established for FBC during its most recent RDA before the Commission.

Rebalancing is required to shift some revenue responsibility to the RS 50 (Lighting schedules) from the Large General Service – Transmission rate schedule (RS 31), as RS 31 is the only rate schedule with an R/C ratio above 105 percent.

A summary of the R/C ratios resulting from the COSA is provided in Table 1-1 below.

Table 1-1: R/C Results

Customer Class	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%

1.6 RATE DESIGN

Section 6.1.4 of the Application discusses the options examined for residential rates and provides the rationale upon which the rate recommendations are based, as well as the reasons that certain other options were not chosen.

The proposals for which the Company is seeking approval from the Commission in relation to residential rates are:

1. to phase out the Residential Conservation Rate (RCR) as the default rate for residential customers by reducing the differential between the Tier 1 and Tier 2 rates over the course of five years such that at the beginning of year five the rate is flat. The phase-in approach is intended to mitigate rate impacts for lower consumption customers.
2. to re-open the closed Time of Use (TOU) offering for residential customers as an optional service, while also restructuring the rate as described in detail in Section 8 of the Application. Long-term continuation of this service offering will be subject to a future review.
3. to phase in an increase to the RS 01 Customer Charge such that at the end of the phase-in period the RS 01 and RS 03 Customer Charges are the same.

Section 6.2 contains a discussion of Commercial rates (namely, the Small Commercial, Commercial, and Large Commercial rates). Commercial rates underwent significant restructuring as a result of the 2009 COSA and RDA and as such, significant changes are not proposed in this Application with the exception noted in the next paragraph. Some adjustments to the fixed-cost portions of the rates are being proposed in accordance with the rate design considerations discussed in Section 3.5.

The exception referred to above relates to the Commercial (RS 21) rate class. In addition to a COSA-based increase in the monthly Customer Charge and Demand Charge rate, FBC proposes to replace the existing declining block structure with a simple flat rate for energy charges.

Section 6.3 deals with the Wholesale rate schedules, which consist of RS 40 – Wholesale Service – Primary and RS 41, Wholesale Service – Transmission. These rate schedules are for the exclusive use of parties that purchase power from FBC for resale to end-users. Those parties are the municipal utilities of Summerland, Penticton, Grand Forks and Nelson, as well as BC Hydro and Power Authority (BC Hydro). The sole change to the Wholesale rates is the addition of a discount provision to RS 40 that will accommodate service to a customer served under that rate that begins to receive service at transmission voltage (i.e., the customer provides its own transformation). This discount is consistent with similar provisions that exist in both the Commercial and Large Commercial – Primary rate schedules and is being proposed in response to a request by a Wholesale customer.

1.7 TRANSMISSION WHEELING RATE DESIGN

Section 7 relates to the Transmission Services offered by the Company pursuant to its Open Access Transmission Tariff (OATT) and Tariff Supplement 7. The Application addresses several separate elements of Transmission service:

1. updates to the pricing of the Point-to-Point (PTP) transmission rates (RS 101 and RS 102) in accordance with the COSA unit costs;
2. updates to the Ancillary Services contained in rate schedules RS 103 – RS 109;
3. revisions to the anti-pancaking provisions contained in RS 101 and RS 102; and
4. removal of the Non-Firm PTP rate (RS 102) from the Electric Tariff.[5]

1.8 OPTIONAL TIME OF USE RATES

FBC has offered optional Time of Use (TOU) rates to all of its customer classes since 1998, pursuant to the 1997 COSA and RDA. Therefore, TOU rates are not new and require no blanket approval for implementation. However, since 1997, the TOU rates have not seen much customer uptake, and had not subsequently been examined against the original rationale behind either the TOU time periods or the pricing. In addition, TOU rates have only become practical to implement on a wide scale since the completion of the Advanced Metering Infrastructure (AMI) project.

FBC seeks to update both the time periods and the pricing with the 2017 RDA, and Section 8 of the Application describes each aspect in detail. The primary change that FBC proposes to the structure of the TOU rates is the addition of a “Mid-peak” period and corresponding rate for all rate classes, which is different from the basic on-peak/off-peak structure that is currently in place. In addition, FBC proposes updating the pricing that applies in each rate period based on cost considerations that reflect the current operating environment.

FBC is also proposing to re-open the TOU rate option for Residential customers regardless of the final approved form of the default residential rate.

Implementing TOU is generally seen as prompting behavioural changes that will provide cost benefits sufficient to prevent cost shifting to non-participating customers. However, there is uncertainty regarding customer participation rates and behaviour, as well as the ability of FBC to realize savings from the shifting of load. For this reason, FBC is proposing to track and review the results of the TOU program and after a period of three years, to provide a recommendation to the Commission regarding the continuation of the rates. FBC is proposing three years as that appears to be a reasonable time frame for significant impacts to materialize and be assessed.

1.9 OTHER RATE SCHEDULES

FBC has a number of other rates not covered by Sections 6 through 8 of the Application. These rates are for Extensions to the Distribution system and other standard charges. FBC has summarized changes to these rates in Section 9 of the Application.

[5] If removal of RS102 is approved then updates to the rates and language in the rate schedule will be unnecessary however the revisions are included in the Application in case removal is not approved by the Commission.

1.10 *GENERAL TERMS AND CONDITIONS*

The final section of the Application contains the Company's proposal for changes to the General Terms and Conditions (as defined earlier, the GT&Cs) contained in the Electric Tariff, the rates associated with its standard charges for connection of service and miscellaneous services, and the customer credits under FBC's distribution extension schedule (Schedule 74 of FBC's Electric Tariff).

The proposed changes to FBC's GT&Cs reflect greater alignment with the current practices and policies of FortisBC Energy Inc. (FEI), where appropriate, as well as reflecting changes to the Company's operating environment and practices since 2009. FBC proposes updating the standard charges and customer credits under FBC's distribution extension schedule for current costs.

1.11 *PROPOSED REGULATORY PROCESS*

FBC proposes that the Application be reviewed through two rounds of information requests followed by an exchange of written submissions. FBC believes a written process is most appropriate given that the Application is very similar to the COSA filed by FBC in 2009, FBC has undertaken a robust stakeholder engagement process including numerous workshops, and the proposed changes in the rate design involve technical issues and analysis that lend themselves to a written process.

2. APPLICATION AND APPROVALS SOUGHT

2.1 *APPLICATION*

FBC files the 2017 RDA with the British Columbia Utilities Commission (the Commission or BCUC) pursuant to sections 58 to 61 of the *Utilities Commission Act* (as defined earlier, the UCA). The Application reviews FBC's existing rate design in all rate schedules and proposes a limited number of rate design changes that will adjust FBC's rates as indicated by an updated COSA and respond to changes in the needs and circumstances of certain rate classes.

Before filing the Application, FBC conducted substantial stakeholder consultation, which included information sessions, a technical COSA workshop, notification mail-outs and meetings with particular intervener groups. FBC believes that the stakeholder engagement process assisted in increasing the level of understanding of stakeholders regarding COSA and rate design-related issues. Further and reciprocally, the process yielded numerous comments on FBC's existing rate design as well as on potential changes that informed FBC's rate design proposals in this Application.

The Application is the result of an overall review of FBC's rate design. A COSA was conducted consistent with standard utility practice to assess the extent to which each rate schedule adequately recovers its allocated cost of service. FBC also conducted a review of its rate schedules considering rate design principles, government policy, stakeholder comments, jurisdictional comparisons, and the analysis of load characteristics and other data. FBC's rate design review included consideration of customer segmentation, alternative rate structures (i.e., flat versus declining or inclining block), the appropriate level of fixed versus variable charges, intra-class and inter-class rate economics, the calculation of demand charges, and various terms and conditions of service.

FBC's current rate design is working as designed. FBC is proposing a number of changes to improve the consistent application of rate design principles among the customer classes and to respond to changing needs and circumstances. The proposed changes include, for example, limited rate rebalancing, and adjusting the level of Customer Charges and Demand Charges for some customer classes such that fixed cost recovery is more consistent across the customer base.

FBC retained EES Consulting Inc. (EES Consulting), a third party expert in public utility rate design matters, to develop the COSA and review and assist in rate design for FBC. EES Consulting provided a COSA for this rate design that follows standard utility practice and is, as well, generally consistent with past practice for the utility. The results of the EES COSA are used to ensure that proposed rates are fair, equitable and not unduly discriminatory. EES Consulting also concludes that FBC's rate design proposals reflect accepted rate design principles and are appropriate. The EES COSA Report, including a summary of the COSA and a review of current rates is attached as Appendix A to this Application.

FBC's proposals are set out below under Approvals Sought and discussed in additional detail in the following sections of the Application. Based on the analysis and considerations set out in the Application, FBC believes that its rate design proposals will result in an appropriate balance of rate design principles and other relevant considerations, are just and reasonable, and should be approved as proposed.

2.2 *APPROVALS SOUGHT*

Pursuant to sections 58 to 61 of the UCA, FBC seeks the Commission's approval of the following, to be effective within a practicable timeframe after such approval is received. Where specific rate levels are indicated below, it should be recognized that the requests are made in reference to rates that are current at the time of filing. In the event that the rates in effect at the time of Commission approval differ as a result of a rate change that occurs in the time between the filing of the 2017 RDA and implementation of any approved rate changes, the specific rates would need to be adjusted accordingly.

Residential Rate Schedules

1. Approval of the following for Rate Schedule 1 (RS 01):
    - 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.
    - 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 03 (the RCR Control Group) and RS 03A (Residential Exempt Rate for Farm Customers).
    - Approval to re-open the optional Residential TOU rate to all Residential customers as discussed in Section 8 of the Application.
    - Removal of RS 03 as this group has been disbanded.

FBC anticipates that it will file an application with the Commission towards the end of the RS 01 phase-in period in order to close the existing RS 03A.

Commercial and Irrigation Rate Schedules

2. In consideration of COSA allocations on a unit cost basis and to improve consistency among rate classes, approval of the following revenue neutral change for Small Commercial (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.

3. In order to better reflect COSA allocations on a unit cost basis and to improve consistency among rate classes, approval of the following revenue neutral change for Commercial (RS 21):
   - An increase in the monthly Customer Charge from $16.48 to $54.00.
   - A flat energy rate of $0.06875 per kWh for all consumption to replace the current declining block rate structure.
   - An increase in the per-kVA Demand Charge from $7.72 to $10.22 in consideration of the COSA fixed costs on a unit cost basis.
   - An update to the transformation discount from $0.053 per kW of Billing Demand to $0.028 per kW of Billing Demand
4. For RS 30, an update to the transformation discount from $2.676 per kVA of Billing Demand to $5.26 per kVA of Billing Demand.
5. In consideration of COSA fixed costs (customer-related and demand-related) and to improve consistency among rate classes, approval of the following revenue neutral change for Large Commercial – Transmission (RS 31):
   - An increase in the monthly Customer Charge from $3,116.03 to $3,195.00.
   - 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.
6. Approval of the following revenue neutral changes to RS 60 – Irrigation and Drainage:
   - An increase in the Customer Charge from $20.06 per month to $22.09 per month in consideration of the COSA unit costs and to improve consistency among rate classes.
   - A decrease in the energy rates from $0.07259 per kWh to $0.07240 per kWh.

Wholesale Rate Schedules

7. Approval of the addition of a discount available to Wholesale Customers served on RS 40 that take delivery at Transmission voltage.

Optional Time of Use Rates

8. Approval of the revised optional TOU rates as described in Section 8 of the Application.

Transmission Service Rates

9. With respect to Transmission Service Rates:
   - Removal of RS 102 from the Tariff as FBC has no need for Non-Firm PTP Rates and the RS 102 pricing is identical to that contained in RS 101.
   - Changes to the anti-pancaking language contained in RS 101 and RS 102 (should RS 102 remain open) 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 (should RS 102 remain open) with pricing as described in Section 7.3 of the Application.
- Changes to the Ancillary Services (RS 103 to RS 109) as described in Section 7.4 of the Application.

General Terms and Conditions

- Approval of the housekeeping and other amendments to FBC's General Terms and Conditions as set out in Appendices G and H.
- The removal from the Electric Tariff 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) as the charges contained in these schedules have been moved to the General Terms and Conditions section of the Tariff.

A Draft Order setting out the approvals sought is attached as Appendix B to the Application.

2.3 *IMPLEMENTATION*

FBC is currently targeting a January 1, 2019 implementation date, which is dependent on the Commission issuing a decision by October 31, 2018. If the Commission is unable to render a decision in this timeframe, FBC requests that the effective date of any rate design changes should, instead, be determined as part of the compliance filing following the Commission's determination of this Application. At the time of its compliance filing, FBC will be in a position to recommend an implementation date that considers the final determinations in the Application decision, confirms implementation requirements and timing, allows adequate time for customer communication and notification, and, to the extent possible, considers the timing of other Commission decisions or pending decisions that may also impact rates.

2.4 *PROPOSED REGULATORY REVIEW PROCESS*

FBC proposes the following draft regulatory timetable as presented in Table 2-1 below. The timetable takes into consideration suggestions from Commission staff, and acknowledges the workload required by the Commission and all parties in this and other ongoing and anticipated proceedings. A draft procedural order has been provided in Appendix C.

Table 2-1: Proposed Regulatory Timeline

ACTION	DATE (2018)
Intervener Registration Deadline	Friday, January 19, 2018
Commission Information Request (IR) No. 1 to FBC	Friday, February 16, 2018
Intervener IR No. 1 to FBC	Friday, March 2, 2018
FBC Response to Commission and Intervener IR No. 1	Friday, April 6, 2018
Commission and Intervener IR No. 2	Friday, April 20, 2018
FBC Response to Commission and Intervener IR No. 2	Friday, May 11, 2018
FBC Final Argument	Friday, June 1, 2018
Intervener Final Argument	Friday, June 15, 2018
FBC Final Argument	Friday, June 21, 2018

The draft regulatory timetable provided above reflects a written process. This Application can be addressed efficiently and effectively by a written hearing process in light of the following considerations, both singly and collectively. First, the COSA generally and appropriately maintains the status quo: it is very similar to the COSA filed by FBC in 2009, as modified by the Commission's decision on that application in 2010, and changes where required are straightforward. Second, on both the COSA and the rate design, FBC has undertaken a robust stakeholder engagement process as described in Section 4 of the Application, including numerous workshops that informed the drafting of its Application. FBC and certain other stakeholders have also had the benefit of observing and participating in other recent rate design processes as well as government engagement on the residential inclining block rate. Third, FBC believes that the relevant facts, such as load characteristics of customers, the current rate design and the impacts of implementing the rate design proposals, are clear and should not be contentious. Fourth, the proposed changes in the rate design involve technical issues and analysis that lend themselves to a written process.

FBC looks forward to working with the Commission and interveners towards an efficient review of this Application.

3. CONTEXT AND CONSIDERATIONS FOR COST OF SERVICE ANALYSIS AND RATE DESIGN

The COSA and rate design processes are completed in consideration of a variety of factors, both internal to the operation of FBC, and in the environment in which the Company operates. These considerations, such as applicable government policies, laws and regulations, previous rate design activities, principles and objectives of rate design and industry trends are discussed in the following sections.

3.1 LEGAL CONTEXT

The Commission's rate-setting authority is set out in sections 58 to 61 of the UCA. A brief summary of these sections is provided below.

- Section 58 of the UCA addresses the situations in which the Commission may order amendment of rate schedules. It states that the Commission may (on its own motion or through a complaint by a public utility or other interested person) after a hearing determine the just, reasonable and sufficient rates to be observed and in force.
- Section 59 of the UCA addresses the issue of rate discrimination. It states that a public utility must not make, demand or receive "an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it." Section 59 of the UCA also provides that a rate is "unjust" or "unreasonable" if the rate is: (a) more than a fair and reasonable charge for service of the nature and quality provided by the utility; (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property; or (c) unjust and unreasonable for any other reason.
- Section 60 of the UCA provides broad rate-setting guidelines for the Commission to consider when determining rates. In setting a rate, the Commission must consider all matters that it considers to be proper and relevant affecting the rate. The Commission must have due regard to the setting of a rate that is not "unjust" and "unreasonable" within the meaning of section 59, provides the utility a fair and reasonable return on any expenditure made by it to reduce energy demands, and encourages public utilities to increase efficiency, reduce costs and enhance performance.
- Section 60(b.1) of the UCA gives discretion to the Commission to "use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period".
- Section 60(c) of the UCA provides general guidelines for utilities with more than one class of service and states that the Commission must: (i) segregate the various kinds of service into distinct classes of service; (ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as self-contained unit;

and (iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates set for any other unit.

- Section 61 of the UCA requires a public utility to file rate schedules with the Commission, to receive the Commission's approval before rescinding or amending a schedule and to charge only those rates that are in accordance with the filed schedules.

3.2 RATE DESIGN PRINCIPLES

The fundamental principles applied in the development of this Application are based on those identified by Dr. Bonbright.[6] The principles adopted by FBC for rate design, and as summarized by the Commission in a previous BC Hydro Decision,[7] in no particular order, are:

- 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).

Rate design is a complex balancing process, as it frequently requires the application of multiple, and sometimes conflicting, principles and the consideration of viewpoints from various stakeholders. In addition, different rate design principles may have varying levels of importance in different contexts. The Commission's decision in BC Hydro's 2015 rate design proceeding recognized that prioritization of different rate design principles may change based on the circumstances specific to each utility at the time of its rate design proceeding:

> The Panel understands that BC Hydro's intent in prioritizing the Bonbright principles is a reflection of the utility's situation at the time of this rate design proceeding. The Panel agrees that prioritization can be expected to change over time as circumstances change and current government policy and other factors

[6] James C. Bonbright, *Principles of Public Utility Rates,* 2nd Edition (Public Utility Reports, Inc., 1961) March 1988

[7] Commission Decision and Order G-45-11, dated March 14, 2011, in the BC Hydro Residential Inclining Block Re-Pricing Application.

> underpin the need for reprioritization of the principles in this instance. The change in the province's forecast need and self-sufficiency requirements, the reduced LRMC (as discussed in section 2.1 of this decision), certain government policy statements and its focus on conservation rates, and changing customer expectations and understandings all need to be reflected in prioritizing Bonbright principles.[8]

FBC, therefore, applies its experience and judgment to consider and balance the most relevant principles in a given context when identifying rate design issues and proposing rate design solutions. FBC does not generally apply the eight principles above in any priority or with any particular weighting. However, the Company does consider that the principle of cost causation (as articulated in Principle 2 but also considered in various other principles) represents an important foundation upon which cost allocation and rate design should rest.

In addition to the eight rate design principles set out above, FBC considers government policy as reflected in the legislation and regulations implementing those policies and in published government energy policy documents.

A summary of the most relevant government policies, legislation and regulations (other than the UCA itself) that have evolved since the filing of FBC's 2009 rate design application, and their impact on FBC's rate design, is provided below.

3.2.1 2010 Clean Energy Act (CEA)

On April 28, 2010, the BC government announced the Clean Energy Act (CEA). The CEA advances sixteen specific energy objectives (not all of which are applicable to FBC) including electricity self-sufficiency, using clean or renewable energy sources, demand-side management and energy conservation, GHG emission reductions targets and encouraging fuel switching to lower carbon intensity energy sources.

The CEA was introduced during the course of FBC's 2009 rate design proceeding and was discussed in the Commission's decision in October 2010 (together with Order G-156-10, the October 2010 Decision):

> The Clean Energy Act (CEA) received Royal Assent on June 3, 2010 and has given a renewed and heightened importance to energy efficiency, conservation, smart meters and smart grid, especially in sections 2 and 17.[9]

As such, the objectives embodied in the CEA were already considered in and incorporated into the Commission's decision regarding the FBC 2009 rate design proceeding as well as the rate design proceedings that were established as a result of the October 2010 Decision. Further, the

8 BC Hydro 2015 Rate Design Decision, Page 14.
9 October 2010 Decision, Page 45.

Commission's decision to approve FBC's advanced metering infrastructure (AMI) CPCN application was informed by section 17.6 of the CEA.

3.2.2 Residential Inclining Block (RIB) Rate Report

In July 2015, BC's Minister of Energy and Mines (the Minister) requested the BCUC to report to the government on the impact of BC Hydro and FBC's RIB rates. This was in response to complaints received by the Minister from some of the customers of these utilities regarding "unreasonable bill impacts", in particular for those who do not have access to natural gas to heat their homes as well as for low-income customers. Pursuant to the Minister's request, the BCUC commenced a consultation process with the utilities and the public and asked the utilities to provide the Commission with reports in response to the Minister's questions. The Commission's final RIB report was released on March 28, 2017. [10]

The Commission's report states that there is a break-even point (at approximately 2500 KWh per billing period for FBC) above which the RIB rate bill is higher than the equivalent flat-rate bill and below which the RIB rate bill is lower, but concluded that this does not constitute a subsidy and neither is unjust, unreasonable, unduly discriminatory or unduly preferential. The report states, "While it is true that customers without access to natural gas are more likely to use electricity for space heating and hot water, it is also important to remember that some customers who do have access to natural gas use electricity for space heating and hot water as well"[11]. However, the report also notes, "While 65.2 percent of FortisBC low-income customers are better off under the RIB rate than the flat rate, FortisBC estimates that 9.7 percent of its low-income customers are more than 10 percent worse off".[12] The report explains that different characteristics of residential customers in FBC's and BC Hydro's service territories (such as the mix of housing stocks) may have resulted in RIB rates having less favourable impacts on FBC's residential customers than BC Hydro's customers, in particular FBC's low-income customers.

In response to the Commission's report, on April 10, 2017 the Minister sent a letter to BC Hydro and FBC.[13] The Minister's letter referred to FBC's upcoming rate design application, asked FBC to take the "opportunity to examine a range of alternative rate designs with price signals for energy efficiency and electrification". The Minister's letter concludes as follows:

> I encourage both BC Hydro and FortisBC to continue to engage with customers and build on the consultation from this process to make sure that the issues raised by customers inform future rate design applications. I also encourage you to consider how proposed rate structures will impact bills for customers choosing electric space and water heating and how this will affect utilities' opportunities for efficient electrifications.

[10] The full record of the BCUC RIB Rate Report process is available at the following link: http://www.bcuc.com/ApplicationView.aspx?ApplicationId=506

[11] BCUC Residential Inclining Block Rate Report, Page i.

[12] BCUC Residential Inclining Block Rate Report, Page ii.

[13] The April 10, 2017 letter is attached to the Application as Appendix J.

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

3.2.3 2016 BC Climate Leadership Plan

The B.C. government's Climate Leadership Plan (CLP) was released in August 2016. The CLP discusses advancement of efficient electrification "by working with BC Hydro to expand the mandate of its DSM programs to include investments that increase efficiency and reduce GHG emissions".[14] The CLP also supported the expansion of the Clean Energy Vehicle program, which provides incentives for electric vehicles purchases, as well as the development of charging infrastructure for zero emission vehicles. Further, the CLP expressed the government's commitment to 100 percent renewable or clean electricity generation except where concerns regarding reliability and costs must be addressed.

The recent amendments to the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) by Order in Council (OIC) 101/2017 represent the first measure by government on low carbon electrification. OIC 101/2017 prescribes programs and projects that encourage low carbon electrification and outlines how a prescribed undertaking for electrification may be considered "cost-effective".[15]

FBC's Community Solar project as well as its investments in electric vehicle charging stations and pending EV Charging Application are examples of FBC's commitment to the policies that were outlined in the CLP.

3.2.4 Postage Stamp Rate Making

The BC government has consistently supported postage stamp rate making. For example, on July 9, 2013, the BC Ministry of Energy and Mines issued a letter to the Commission in support of FEI's application for common rates. The letter notes the following:

> From a public policy perspective, the Ministry is of the opinion that a common rate resulting from the proposed amalgamation of FortisBC Energy Utilities will have benefits for all Fortis BC Energy customers in British Columbia.

[14] BC's Climate Leadership Plan, Page 28.

[15] "Cost-effective" means, for this purpose, that the present value of the benefits of undertaking (defined as all revenues the utility reasonably expects to earn as a result of implementing the undertaking, less revenues that would have been earned from the supply of undertaking electricity to export markets) exceeds the present value of the costs of the undertaking (defined as cost utility reasonably expects to incur to implement the undertaking, including without limitation, development and administration costs) when both are calculated using a discount rate equal to the utility's weighted average cost of capital over a period that ends no later than a specified year.

> Government policy has been to promote access to energy services on a postage stamp rate basis so that all British Columbians benefit from access to services at the lowest average cost.[16]

More recently, the BC Ministry of Energy and Mines has issued a letter to the Commission, dated September 17, 2015, stating that postage stamp ratemaking continues to be provincial government policy. In this letter, the Ministry states that:

> Postage stamp rates provide access to services at the lowest average cost, promote investment equality across BC Hydro's service area, streamline regulatory requirements and effective utility management, and minimize potential regional rate impacts as BC Hydro invests in its infrastructure.[17]

Consistent with government's message regarding the cost-effectiveness of postage stamp rates, the Commission's recent decision in BC Hydro's 2015 rate design proceeding acknowledged BC Hydro's argument that there is an economic basis for postage stamp rates and maintained BC Hydro's postage stamp rates:

> The Panel notes BC Hydro's argument that they are a practical necessity because of the difficulty and costs involved in separating the cost of service to different regions, which thereby provides an economic basis for these rates.[18]

Similarly, in the October 2010 Decision (on FBC's 2009 COSA and RDA), the panel recognized government's support for postage stamp rates[19] and maintained postage stamps rates across FBC's service territory.

Postage stamp rate setting, however, does not necessitate that rates must or should be the same across the service territories of different utilities across the province. The Commission said the following in its decision on FBC's 2012-13 Revenue Requirements application (at page 20):

> FortisBC operates with a different set of supply resources and with a different customer base in terms of geography, population density and the residential/commercial/industrial mix it faces. The Commission panel has no mandate, nor does it find it appropriate, to require FortisBC to manage its utility business to produce rates or programs identical to those of BC Hydro. The Commission Panel believes that FortisBC's responsibility is to provide safe and reliable service in a cost-effective manner consistent with British Columbia's energy objectives. To do so, FortisBC must design and manage its system based on the resources available to it and the needs of its customers. This, at times,

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[16] FEU Common Rates, Amalgamation Rate Design Reconsideration Phase 2, Exhibit C3-1.
[17] BC Hydro 2015 Rate Design Application, Appendix C-1C.
[18] BC Hydro 2015 Rate Design Decision, Page 59.
[19] October 2010 Decision, Page 69.

may result in rates that are greater than those of BC Hydro and potentially times when they are less.

3.3 FBC RATE DESIGN HISTORY AND PREVIOUS COMMITMENTS

3.3.1 Introduction

FBC and its predecessors previously filed three major rate design applications with the Commission, in 1983, 1997 and 2009. The outcomes of these processes are reflected in the rates as they exist today. Additionally, the directives in the Commission's October 2010 Decision (on FBC's 2009 COSA and RDA) resulted in a number of specific rate related applications being filed since 2009. Significant rate-related determinations since the 2009 rate design proceeding, which are also embedded in today's rates, are summarized in Table 3-1 below. Each proceeding's history as well as previous directives and commitments made are discussed further in the following sections.

Table 3-1: FBC Rate Design - Major Proceedings and Approvals Since 2009

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).

[20] Demand ratchets are generally included in electric utility rates to reduce the risks of serving certain types of customers who have potentially large swings in demand during the year. Under demand ratchet mechanism electric rates are billed based on either the peak demand by a customer in the current month, or some percentage of the peak demand for that customer during previous months even if the actual demand in that month is lower.

Application	Key Rate Design Methodologies Approved
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.

3.3.2 Regulatory History of FBC's Rate Design

3.3.2.1 2009 COSA and RDA

FBC's 2009 COSA and RDA, filed in October 2009, was the Company's first rate design application following the release of the B.C. Government's 2007 Energy Plan (and subsequent enactment of legislation and regulations to implement the related policies in 2008), which among other things highlighted the role of "new rate structures that encourage energy efficiency and conservation". Furthermore, during the course of the 2009 COSA and RDA proceeding the BC government announced the *Clean Energy Act* (as defined above, the CEA) in April 2010, which gave heightened importance to energy efficiency and conservation by pointing the utilities[21] toward introducing, among other things, smart meters, conservation rates and industrial stepped rates.

In line with these policies, in the October 2010 Decision the Commission directed FBC to develop and file a plan for an inclining block rate for its residential customers. FBC was also directed to work with industrial customers with a goal to introduce a stepped rate for transmission service similar to BC Hydro's RS 1823 and to work with Celgar to examine the application of stand-by rates.[22] The October 2010 Decision further approved FBC's proposal to flatten the Small Commercial (RS 20) energy rates from the existing declining block and to move from a three-step to two-step declining block rate for Commercial (RS 21) in which the first block rate of RS 21 and the flat rate of RS 20 are the same.

The Commission also approved FBC's proposal to separate the demand component of the Large Commercial (RS 31) and Wholesale (RS 40 and RS 41) rates into a power supply charge and a wire charge to provide better price signals to those customers. Further, the Commission stated that the demand ratchet used to calculate billing demand under the wires charge for both Large Commercial and Wholesale should be consistent, as in both cases there is enough diversity of loads contributing to system peak to justify an 80 percent demand ratchet.

3.3.2.2 2011 Residential Inclining Block (RIB) Rate Design Proceeding

Pursuant to the October 2010 Decision, FBC filed an application for approval of a RIB rate on March 31, 2011.

Order G-3-12 and the associated reasons (together, the RIB Decision) approved FBC's proposed two-tier RIB rate structure consisting of a RIB rate threshold of 1,600 kWh and the resulting rate differential between the block one and two rates.

As part of the directives in the RIB Decision, FBC was directed to apply a Pricing Principle to future rate increases for the years 2012 to 2015 such that the Customer Charge was exempt from general rate increases, other than rate rebalancing increases; the block 1 rate was subject to general and rebalancing rate increases; and the block 2 rate was increased by an amount sufficient to recover the remaining required revenue. Since 2015, any general rate increases have been applied in an equal percentage to each rate component.

The RIB Decision also directed the Company to close its existing TOU rate for residential customers to new participants. Correspondingly, FBC closed that TOU rate in 2012.

[21] As stated in Commission's October 2010 Decision on FBC's 2009 COSA and RDA, while government communication on this issue only focused on BC Hydro, a direct link could be drawn to FBC.

[22] The Commission also determined that Celgar is not eligible to be served under RS33 and should be transferred to RS31.

3.3.2.3 2013 Stepped and Stand-by Rates for Transmission Customers (Stage I, II, III and IV)

In the October 2010 Decision, the Commission directed FBC to consult with its industrial customers with a goal of introducing a stepped rate for transmission service similar to BC Hydro's RS 1823. The Commission further recommended that FBC and Celgar reconsider the options available to them, such as stand-by service.

Following the Commission's decision, Celgar filed a complaint on March 21, 2011 regarding the failure of FBC and Celgar to complete a General Service Agreement (GSA) and the application of RS 31 contract demand. In reviewing Celgar's complaint the Commission described Celgar's load as being served by a combination of self-generation, FBC's supply at embedded cost rates and additional supply from FBC (the margin). In that context, the Commission Panel stated that a stepped rate could be an appropriate mechanism for recovering the costs of supplying power to serve the margin and by way of Order G-188-11, dated November 14, 2011, directed FBC to submit an application for a two-tier stepped transmission rate. The Commission also stated that the rate should consider not only the costs of obtaining additional supply on the margin but also the costs of infrastructure to provide the capacity to deliver the energy and therefore directed FBC to file an application for a standby rate with BC Hydro's RS 1880 standby rate as a consideration.

In response to the Commission's directives in Order G-188-11, FBC filed an application seeking approval of a stepped rate and a standby rate for transmission voltage customers on March 28, 2013 (SSR Application). In the SSR Application, FBC noted that, with the exception of the standby service rate, the Company was not convinced that its proposals were in the best interests of its customers and it would not have asked for approval of the proposals absent the Commission's directive.

The Commission Panel reviewed FBC's proposed stepped rate and concluded that FBC's pricing principles were consistent with Order G-188-11. However, the Commission commented that it had not predetermined that a rate that met these principles would be approved; rather it had directed only that the rate was to be brought forward for review by Commission. Ultimately, the Commission Panel agreed with FBC and in its Order G-67-14 on Stage I of the SSR Application together with associated reasons (together, the SSR Stage I Decision) determined that the proposed stepped rate should not be mandated at that time.

The SSR Stage I Decision and subsequent Orders G-46-15, G-93-15 and G-149-15 in Stages II, III and IV of the SSR Application proceeding defined and determined the rates and terms and conditions of RS 37 – a new rate schedule for existing and future FBC customers with self-generation capacity – as well as Celgar's specific issues including its contract demand under RS 31, its standby demand limit and its standby billing determinant.

In the SSR Stage I Decision, the Commission Panel approved FBC's proposed energy charge with minor changes. The energy charge for replacement power under RS 37 is determined by the hourly Powerdex Mid-Columbia (Mid-C) market price, cost of wheeling the energy from the

Mid-C hub, system losses as well as an administrative premium of 10 percent. The power supply demand charge is not applicable to standby service due to the market-based pricing of the RS 37 energy charge. The Commission further agreed that a customer taking service under RS 37 must have contracted to receive service under one of the Company's commercial rates with a demand charge component (such as RS 31 for Celgar). However, the Commission did not approve the standby service rate schedule at that time and directed FBC to file a revised application for service restrictions, as well as determination of the contract demand in the underlying rate and the contract demand during periods of standby service.

On June 26, 2014, FBC submitted the revised RS 37 filing in compliance with the SSR Stage I Decision. In the Stage II SSR Decision,[23] the Commission determined the standby restrictions for both back-up and maintenance services. Further, the Commission established three key components of the standby service, as follows: (i) contract demand under the underlying rate schedule (RS 31), which is the maximum amount of full service a customer is eligible for under underlying rate schedule; (ii) standby demand limit, which is the maximum demand that FBC is required to supply to a customer under RS 37; and (iii) standby billing determinant used for determination of wires charge and set at an amount between zero and 100 percent of a customer's standby demand limit. The Commission also determined that at any hour if demand is higher than the sum of RS 31 contract demand and standby demand limit then a penalty shall apply and asked stakeholders to provide additional evidence regarding this issue in the next phase of the proceeding.

In the Stage III Decision,[24] the Commission Panel established a penalty mechanism for exceeding the contractual supply limits. Furthermore, the Commission established Celgar's contract demand under RS 31 and standby demand limit at 3 MVA and 42 MVA respectively.

Finally, in the Stage IV Decision,[25] the Commission Panel determined Celgar's standby billing determinant at 40 percent of its standby demand limit equal to 16.8 MVA.

3.3.2.4 2015 Self-Generation Policy Proceeding

Order G-60-14 and associated reasons (together, the PPA Decision), dated May 6, 2014, approved a new Power Purchase Agreement (PPA) under BC Hydro RS 3808 between BC Hydro and FBC. As part of the new PPA, FBC is prohibited from selling RS 3808 electricity to a FBC customer when the same customer is selling (exporting) self-generated electricity, unless a portion of the customer's load equal to or greater than the customer specific baseline is not sourced with any RS 3808 electricity (Section 2.5 Restrictions). In the PPA decision, the Commission commented that if FBC had a Commission-approved self-generation policy, this

[23] Commission Order G-46-15 issued on March 24, 2015.
[24] Commission Order G-93-15 issued on May 29, 2015.
[25] Commission Order G-149-15 issued September 22, 2015.

restriction could have been removed, improving regulatory efficiency in FBC's service area. The Commission directed FBC to file a self-generation policy application.[26]

FBC filed its Self-Generation Policy Application on January 9, 2015 (SGP Application). After a procedural conference, the Commission Panel separated the review of the SGP Application into two stages:

- Stage I: to evaluate FBC's high level policy statements and supporting policies that will define the building blocks of the second stage of review; and
- Stage II: to review and establish FBC Generation Baseline (GBL) guidelines.

In Order G-27-16 and associated reasons dated March 4, 2016 (together, the SGP Stage I Decision), the Panel agreed with FBC that each self-generation project has to be evaluated on a case-by-case basis; however, the Panel found that the proposed high level policy statement was not comprehensive enough to enable FBC to set the context under which to make such an evaluation or to result in the eventual removal of the Section 2.5 Restrictions. As such, the Panel directed FBC to include a comprehensive self-generation policy in its Stage II filing, in addition to the GBL guidelines.

On November 10, 2016, FBC filed Stage II of its SGP Application, seeking among other things, approval of the Self-Supply Obligation Guidelines. On June 9, 2017 and by Order G-90-17, the Commission suspended the regulatory time table for the proceeding in order to have sufficient time to take FBC's responses to Commission's IR No.1 into consideration.

On August 10, 2017 the Commission requested comments on outstanding issues and sought input from participants regarding the best process moving forward. Submissions were made by FBC and registered interveners. Specifically, FBC submitted that the process should be allowed to continue. The Company awaits a determination from the Commission on whether or how the process will continue.

3.3.2.5 2016 Net Metering Program Tariff Update

The FBC Net Metering (NM) Program (RS 95) was initially established in July 2009 by way of Commission Order G-92-09 in response to the BC Government's 2007 energy policies. RS 95 is available to residential, commercial and irrigation customers with clean and renewable self-generation, is intended to only offset annual consumption, and is subject to a nameplate capacity cap of 50 kW.

On April 15, 2016, FBC filed its NM Program Tariff Update Application (NM Update Application) in order to clarify the intent of the program and the treatment of annual unused net excess generation (NEG) by RS 95 customers. In the NM Update Application, FBC stated that the

[26] In addition, Order G-67-14 regarding FBC's standby rates also directed FBC to file a self-generation policy application.

intent of the NM metering program is for customers to offset part or all of their own consumption and not to provide a means for independent power producers to sell power. To solve this issue, FBC proposed some changes in the wording of RS 95 as well as a proposal for a rate to be paid to RS 95 customers for their annual unused NEG. The Company also proposed the creation of a KWh bank that carries monthly NEG forward to offset consumption in a future billing period, rather than the current practice of settling NEG on a billing-period basis at the prevailing retail rate.

The Commission issued its Order G-199-16 and associated reasons (together, the NM Update Decision) approving FBC's proposed changes to RS 95 that clarify the intent of the program and confirmed that new customers will not be accepted into the NM Program if their proposed generating capacity exceeds their anticipated annual consumption. In addition, FBC's proposal for a billing calculation method was approved. However, in a split decision the Commission denied FBC's proposal for an annual NEG purchase rate and creation of a kWh bank.

On March 17, 2017, FBC filed an application for reconsideration and variance of the NM Update Decision, in part. The Commission decided that the reconsideration process should proceed to the second phase of the Commission's reconsideration process. Apart from issuance of the Commission's decision, phase two of the reconsideration process has been completed with the filing of the Company's reply argument on November 9, 2017.

3.3.3 Past Directives and Commitments

During previous regulatory processes, FBC has either received specific direction from the Commission, or has itself committed to undertake specific activities or analysis as part of its 2017 COSA and RDA. The Company provides the following summary of past directives and commitments.

3.3.3.1 2009 COSA and RDA – Commission Order G-156-10

In the October 2010 Decision, the Commission provided a number of directives. These directives are summarized beginning at page 117 of the October 2010 Decision.

With the exception of the directives related to the Irrigation Rate Class, each of the directives has been satisfied, either during further process related to the 2009 COSA and RDA, or in subsequent applications. The Irrigation-related directives are discussed in greater detail in Section 6.2.6 of this Application, and are set out below.

- FortisBC is directed to determine the nature of its Irrigation customers, to identify which of them are irrigation or drainage, and to ascertain their eligibility for service under RS 60 and RS 61.
- The Commission Panel further directs FortisBC to consult with its bona fide Irrigation customers to determine the conditions it should attach to RS60 and

RS61. Finally, the Commission Panel directs FortisBC to undertake load research to establish the load characteristics of the Irrigation class.

- Until FortisBC is better able to demonstrate the load characteristics of the Irrigation class and reflect these in its COSA, the Commission Panel determines that the Irrigation class should be exempt from rate rebalancing, and subject only to base adjustments associated with FortisBC revenue requirement and BC Hydro flow-through.

3.3.3.2 Application for a CPCN for the Advanced Metering Infrastructure Project

In response to an information request, from the Commission, in the Company's Application for a CPCN for the Advanced Metering Infrastructure Project (AMI Application), with respect to the impact of the AMI system on the costs involved in a meter reconnection, the Company committed to address the issue in the next COSA filing. The question and response were as follows:[27]

> Will FortisBC be reducing the reconnection charge considering the ability of the AMI reconnect feature? If not, please explain why not.
>
> **Response:**
>
> Once the AMI project is completed, the marginal cost of a remote reconnection is likely to be less than $10, meaning that in theory the reconnection fee could be dropped substantially. However, FortisBC proposes to maintain the current reconnection charge until the next COSA, in order to better understand all costs associated with the new processes. The reconnection charge also deters disconnections, the costs of which are borne by all customers. Although disconnection process costs would go down with the AMI project, there are still related costs such as site visits for 50% of vacant sites and 100% of non-pay sites (Exhibit B-1, Section 5.3.3, p60) and the contact centre processes related to non-pay disconnects.

FBC addressed the issue of remote reconnections for vacancy in a compliance filing to the Commission pursuant to Order G-184-15,[28] where FBC proposed to discontinue charging the meter connection fee to premises that have remote reconnection capabilities, following a disconnection for vacancy, and charge instead the account set-up fee. The Commission accepted FBC's process changes in Letter L-1-16, and determined that no tariff amendments or approvals were required to make the change.

[27] Application for a CPCN for the Advanced Metering Infrastructure Project, Exhibit B-6, IR 1.92.2.1.
[28] Order G-184-15 - FortisBC Inc. – A Complaint filed by M.W. concerning a $100 meter connection charge.

FBC has included a standard charge for remote reconnections following disconnection for non-payment or other violations of the Company's General Terms and Conditions. The fee reflects the shift of the predominantly field work-related costs of manual reconnection to the administrative-related costs of a remote reconnection. The remote reconnection charge also aligns with the Account Setup Charge, where the administrative requirements of both tasks are largely similar. Further details of the standard charge for remote reconnections is provided in Section 10.5.2 of the Application and in Appendix D.

3.3.3.3 Other Related Processes

FBC has other rate-related applications before the Commission at the time of filing the 2017 RDA related to its NM Program, LED Lighting, EV Charging Service and Self-Generation Policies. As these processes are expected to unfold independently, FBC is not addressing the specifics of the separate applications in this process. There are no aspects of the 2017 RDA that are contingent on the other applications, although for example, should the compensation rate for NEG change as a result of the application for reconsideration and variance of the NM Update Decision, the change would be reflected in an updated version of RS 95.

3.4 *THE CHALLENGE OF FIXED COST RECOVERY*

Rate design for FBC, like most utilities, is fundamentally based on cost causation for various rate classes. Rates may also be designed to pass on certain price signals and encourage particular behaviours, such as with TOU rates. Full recovery of fixed costs by way of fixed charges has generally not been adopted by utilities because this can discourage energy efficiency investments by customers and may have disproportionate impacts on low-usage customers. Historically, consumers have relied on FBC for substantially all of their electricity needs, which ensured that all customers shared in the costs of operating the utility in a reasonably fair manner. However, a number of emerging trends and technologies are driving changing requirements that customers have for utility service. These include:

- increasingly affordable distributed generation technologies;
- energy efficiency and other consumer demand-management technologies; and
- electric storage technologies.

The adoption of these technologies tends to reduce consumption or change consumption patterns for customers, and requires utilities to acquire new technologies or information systems capacity to manage their systems. These trends can simultaneously increase costs and/or reduce customer consumption.

One implication of these developments for utilities is that elements of the current rate design paradigm, which have worked well in the past, may be less well positioned for a future in which many customers have cost-effective options to improve the energy efficiency of their homes and businesses or generate electricity onsite.

FBC is not alone in recognizing that challenges may be on the horizon. BC Hydro summarized similar concerns in its 2017 Net Metering Evaluation report as follows.

> As solar generation becomes more accessible, BC Hydro expects to see greater participation in the Net Metering program. A sustained increase in the number of Net Metering customers will eventually contribute to a decline in base customer revenues, which could result in upward rate pressure. At some point, this may become a significant issue for BC Hydro, as these partially self-sufficient customers still require energy from BC Hydro on demand. Yet, under our current rate structure, they would not pay their proportionate share of the utility's infrastructure cost as BC Hydro recovers the majority of its fixed demand related costs through the variable energy rate. This means the majority of our infrastructure costs and upgrades may be borne by a declining number of non-participating customers.[29]

As more customers reduce their total energy use or total use of utility-supplied energy, utilities must be able to raise rates to recover adequate revenues to cover their costs, which are substantially fixed in nature. This is a result of the manner in which rates are set, and the inequitable impact on customers is caused in part by the mismatch between the ways costs are incurred (e.g. for NM customers there is a high percentage of fixed costs for delivery capacity that is still needed, even if on a day-to-day basis they generate a substantial portion of their own energy requirements) and recovered (largely through volumetric charges).

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. A customer with distributed generation, for example, requires a grid connection in order to balance consumption and generation, which are seldom matched perfectly, and to provide energy when the customer-owned generation is not producing. Such use, however, may result in no revenue to the utility under the Company's current Net Metering provisions, or only in the partial recovery of fixed costs even if the customer is not part of the Net Metering Program.

The issue here is that the costs of maintaining the infrastructure and standing ready to deliver energy when required will necessarily be recovered from customers in general – which will lead to general rate increases.

[29] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/20170426-BCH-Rate-Schedule-1289-Net-Metering-Eval-RPT-4.pdf, Section 9.1.2.

3.5 TRENDS IN RATE DESIGN

As stated above, in recent years a number of emerging technological and market trends, such as increasingly affordable distributed generation technologies and improved demand management technologies, are driving changes in some electricity customers' consumption behaviour and requirements. These changes potentially diminish intra-class fairness as well as lead to rate and/or revenue instability, if these issues are not addressed. As a result, these new challenges are often reflected in utility rate design decisions, particularly in those jurisdictions where these new technologies are more prominent.

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

In terms of prevailing practices in regard to residential rate structures, and as indicated in the EES COSA Report, flat rates, followed by inverted rate structures, continue to be the most common types of electric utility rate structures in Canada with optional TOU rates available to the residential customers of some utilities.

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

[30] Exhibit A2-2 in the FortisBC Energy Inc. 2016 Rate Design Application proceeding.

[31] In Ontario, costs of generation are recovered through the time of use charges while the costs of transmission are collected through rates that are set uniformly across the province.

Table 3-2 below shows the current fixed cost recovery embedded in the current rates when assessed against the 2017 COSA unit costs.

Table 3-2: Current Fixed Cost Recovery Detail

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

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

The increase in the Customer Charge to a minimum of 55 percent of the COSA customer-related unit cost, along with an increase in the demand-related charges in certain rate schedules, will help to mitigate the transfer of costs between customers on both an inter-class and intra-class basis. These changes are all part of the current Application, and if approved

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

would function to stabilize revenues for FBC. However, all of these changes will be revenue neutral overall for the utility.

3.6 *A POTENTIAL NET METERING RATE*

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

There are fixed costs related to the delivery of electricity to customers that do not vary with the amount of power that is consumed. The poles, wires, and generation equipment used to generate and deliver electricity, as well as the FBC employees that work to provide service that is reliable and safe, will all to a large extent be necessary, regardless of the amount of energy delivered. In light of this, FBC did review potential NM rate variants that have been introduced or are under consideration in other jurisdictions, such as a demand-related rate. If FBC were to implement such a rate, it would be optional in the sense that it would be tied to the optional Net Metering Program, and mandatory in the sense that all Net Metering customers within the applicable rate classes would be required to utilize the rate.

The demand-related NM option that FBC examined is an additional rate that would recognize the peak demand placed on the FBC system by NM customers and that would allow FBC to mitigate against the cost shift that can occur between these customers and the rest of its customers. The potential for this cost shifting was noted in a 2015 study by the Massachusetts Institute of Technology which concluded:

> By enabling those utility customers who install distributed solar generation to reduce their contribution to covering distribution costs, net metering provides an extra incentive to install distributed solar generation. Costs avoided by households that install distributed solar generation are shifted to utility shareholders and/or other customers. Recovering distribution costs through a system of network charges that is more reflective of cost causation and that avoids the current direct dependence on electricity consumption would remove the extra subsidy and prevent this cost shifting.[34]

For rates that do not include a demand-related charge, it is common that fixed costs are recovered in two ways, through a monthly or bi-monthly fixed charge or as a portion of the energy (kWh) rateDistributed generators do not necessarily cost less to serve than other customers. However, because they offset some or all of their energy usage they may no longer

[34] http://energy.mit.edu/wp-content/uploads/2015/05/MITEI-The-Future-of-Solar-Energy.pdf, Page 220.

pay a commensurate share to maintain the grid. FBC is aware that BC Hydro is also monitoring this situation. BC Hydro stated in its April 26, 2017 Net Metering Evaluation Report No. 4, ***"…*** *as the participation in the Net Metering program increases we may need to review the recovery of fixed infrastructure costs from BC Hydro's Net Metering customers and apply appropriate charges to these customers as necessary."*

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

4. PUBLIC CONSULTATION

4.1 *Consultation Overview and Objectives*

FBC is committed to engagement, information sharing and building long-term cooperative relationships with customers, other stakeholders and First Nations. Feedback was an important part of the process leading up to the filing of the 2017 RDA, both in identifying issues to be addressed and in developing proposals to address them.

In the following sections, the Company describes in further detail customer communication and consultation that has occurred with respect to the 2017 RDA.

FBC has received a great deal of feedback from customers on the RCR since its implementation. In developing the 2017 RDA, FBC wished not only to provide opportunities for further discussion on that topic, but also to provide customers with additional context for FBC's rate design options and to engage with customers more generally on issues whether of interest to them or of interest to FBC.

In this regard, therefore, the objective of the formal consultation undertaken in advance of the 2017 RDA was to engage with customers in a manner that would provide them with background on how rate structures are designed and to obtain their feedback.

FBC wished to promote and encourage customer participation in the application process, including by providing opportunities for customers to attend face-to-face sessions and to submit ideas, whether in person, electronically or otherwise.

Information provided to customers during the public consultation sessions included, but was not limited to:

- the way customers are grouped together (segmentation);
- the allocation and distribution of the costs associated with providing electricity (COSA); and
- rate structure and rates used to recover these costs from customers (rate design).

4.2 *Residential Consultation*

Given the input received by the Company since the inception of the RCR, and the interest in this matter on the part of local and provincial government, the gathering of feedback was seen as essential to the "public understanding and acceptance" principle of rate design the Company seeks to recognize. However, as noted above, FBC also wished to engage with residential customers more generally.

In the process of developing the 2017 RDA, FBC held a series of open houses for customers in its electric service territory. These sessions provided information on how rates are set and served as a means of gathering customer feedback and input on potential rate options.

The principal target audience of the open houses was the residential customer base; however, the COSA information provided was generic enough to apply to all customer classes. Correspondingly, representatives of the Commercial, Wholesale and Irrigation classes were in attendance, as were some local elected officials.

In order to leverage consultation efforts, Commission staff attended FBC's first set of open house presentations in order to explain the process of a rate design application and the role of the Commission generally as well as with specific regard to the 2017 RDA. In the second set of open house sessions, Commission staff attended to observe and provide information to attendees upon request.

Two sessions were held in each of Kelowna, Osoyoos and Castlegar in June and July 2017.

The first session in each city was focused on providing customers with information on the COSA process and about how rates are set, as well as on gathering initial feedback from participants. The second session was scheduled to explain the results of the COSA and to present the rate options that FBC developed based on the feedback provided at the first round of sessions. The information presented at the second session in each city included sample rate structures as well as the resulting customer annual bill impacts that could be expected were the options to be implemented. The residential rate design options presented at the open houses are those that are detailed in Section 6.1.4 of the Application and the presentation materials are attached to this Application as Appendix E.

FBC provided analysis and thoughts regarding the various rate options, but did not provide a recommendation for implementation. For interested customers who could not attend the sessions, web consultation was an option to receive information and provide feedback.

All open house presentation materials and handouts were made readily available online on the FBC website at www.FortisBC.com/electricityratedesign.

Apart from the opportunity to make comments during each session, attendees were given a feedback form to fill out if they chose to leave behind any written comments. Feedback forms were collected at the end of each open house in Castlegar, Kelowna and Osoyoos. Representatives from the Residential, General Service, Large General Service, Irrigation and Municipal rate classes signed into the sessions.

4.2.1 Session Locations and Timing

FBC held the public information and public feedback sessions in the three communities as follows:

Information workshop dates:

Session 1

- Kelowna on Tuesday, June 27, 2017
- Osoyoos on Wednesday, June 28, 2017
- Castlegar on Thursday, June 29, 2017

Session 2

- Kelowna on Tuesday, July 25, 2017
- Osoyoos on Wednesday, July 26, 2017
- Castlegar on Thursday, July 27, 2017

The consultation process was advertised in local media across FBC's electric service territory and on the Company's website, as well as by email to customer and government stakeholders and First Nations.

All presentation material was posted to the FBC website in advance of each session.

4.3 *COMMERCIAL CONSULTATION*

Commercial customers take service under RS 20, RS 21, RS 30 and RS 31. Of these rate schedules, FBC is only proposing structural changes to RS 21. With no proposed changes to the structure of the remaining commercial rates, there was no content for a workshop or session specific to these rates. However, FBC did engage with its largest commercial customer separately, and the commercial umbrella groups, the Commercial Energy Consumers (CEC) and Industrial Customer Group (ICG), were provided with information and notification of both the public open houses and the technical COSA workshop.

For the RS 21 customers, FBC sent letters to every account holder outlining the proposal to change the rate from a declining block structure to a flat rate, and inviting comment.

The Company received three responses from RS 21 customers. Redacted copies of these letters are attached as part of Appendix F. The redactions are made to protect the personal information of the individuals.

4.4 *WHOLESALE CONSULTATION*

During the same timeframe as the public open houses were being conducted, discussions with the Wholesale customers taking service under RS 40 and RS 41 were also underway. On July 13, 2017, FBC hosted a conference call with the BC Municipal Electrical Utilities (BCMEU) members and BCMEU's counsel to provide preliminary information and to solicit any input and perspectives that the group had. Primary among these was to ascertain whether the individual utilities still wished to be treated as two classes for the purposes of the COSA (rather than each utility being treated as an individual customer class), which was confirmed to be the case. The option of a transformation discount available to RS 40 customers was raised by the BCMEU and has subsequently been included in the FBC proposals.

FBC also had a separate meeting with the City of Penticton at that city's request on August 9, 2017 to discuss FBC rates.

Members of the BCMEU attended both the public open houses and the technical COSA workshop.

4.5 TECHNICAL COSA WORKSHOP

Attached as part of Appendix E are the presentation materials from the technical workshop held in Vancouver on October 25, 2017. The focus of this session was the COSA process and findings and specifically the assumptions and inputs to the COSA model that form the foundation of the rate design proposals.

The workshop presentations were provided by FBC and EES Consulting. The session was attended by intervener groups, as well as individuals from the residential, wholesale and irrigation customer classes and was also broadcast.

4.6 CONSULTATION RESULTS

This section summarizes the feedback received both at the conclusion of each of the open houses conducted by FBC regarding the COSA and rate design options, and through the online feedback form.

4.6.1 Open House Comments

During the 6 open houses held in Castlegar, Kelowna, and Osoyoos, FBC staff recorded comments and questions from the participants. The verbatim comments are included in Appendix F. As shown in the notes from the open houses, the questions and comments were diverse, ranging from queries on the role of the BCUC, general questions on FBC operations and rate setting, as well as industry and FBC regulatory policy.

During the June open houses, which were primarily focussed on general COSA and RDA topics, there were several recurring themes during the discussion. With regard to existing rates, FBC received feedback such as:

- "your system doesn't encourage conservation" (Osoyoos – June)
- "why can't you segment residential customers to people who have access to natural gas, and people who don't?" (Osoyoos – June)
- A number of people suggested that the two tiers should be adjusted. People think tier 1 is too low (Castlegar – June)

- “You’re unduly discriminatory, you’re penalizing customers for using more energy.” (Kelowna – June)

With regard to potential rates, there were a number of questions and comments regarding options that could be considered, such as:

- “Do you think the BCUC would entertain the idea of customers choosing time of use or RIB rate?” (Kelowna – June)
- “I would argue Time of Use wouldn’t address the fact that over 50% of energy use is for space heating and you need to heat your house when you need to heat your house. Time of Use wouldn’t help that.” (Osoyoos – June)
- “has there been any thought to changing the thresholds in the winter months? (ie seasonal rate)” (Osoyoos – June)
- “Have you ever considered changing level/standard of service for customers in order to change the Revenue requirements for each rate class?” (Kelowna – June)

At the July open houses, at which several rate design options were presented for discussion, there was less general discussion from participants. On the topic of rates, however, comments were consistent with the June sessions. Participants continued to express frustration with the existing RCR rate structure.

The wide variety of comments can best be recognized by reviewing the notes included in Appendix F.

In summary, the open house discussion was dominated by expressions of dissatisfaction with the current default residential rate structure. The preferred option to resolve the perceived issues was to return to a flat rate, or in the alternative, to design an alternative rate for customers without natural gas. Reception to the re-introduction of a TOU rate was mixed.

4.6.2 Open House Surveys and Written Submissions

A total of 161 customers and stakeholders attended the six open houses across the FBC service territory. The Company was encouraged by the nature of the topics and feedback discussed throughout the open houses. Generally, participants indicated an appreciation for the effort made by FBC to conduct local consultation sessions and for the opportunity to present their views.

The options and input received at the sessions are discussed at length in the residential rates section (Section 6.1.4).

In addition to hearing the engaged discussion at the sessions themselves, FBC collected five feedback forms and five written submissions as a result of the mail and email notifications of the process and open houses. The common feedback contained in the written submissions were that respondents:

- are not in support of the residential conservation rate;
- would like a "no access to natural gas" rate implemented; and
- TOU rates may provide an option to some customers.

5. COST OF SERVICE AND RATE REBALANCING

This section of the Application summarizes the analyses performed by EES Consulting in conducting the COSA, which provides the basis for the rate design recommendations made by the Company. This information is drawn primarily from the EES COSA Report, the full version of which is included as Appendix A. EES Consulting has been retained by FBC to undertake COSA and RDA work since 1982 and thus has considerable familiarity with the Company, its customers and its circumstances.

An introduction on the industry standard methodology that is commonly used in the COSA process forms part of the EES COSA Report. The following sections summarize the COSA methodology as well as major assumptions and the findings in the EES COSA Report.

5.1 *2017 COSA METHODOLOGY*

FBC last filed a comprehensive COSA in 2009. The resulting final rates and rebalancing scenarios were accepted and approved in 2010 and 2011.[35] The methodology from the 2009 COSA and from the associated Commission decisions (in the event of divergence from the COSA that was filed) were considered as a starting point when performing the 2017 COSA. Changes that have occurred over the past 8 years on the FBC system, in the overall electric industry, and trends in utility ratemaking were all also considered when developing the 2017 COSA.

The 2017 COSA uses the 2017 Approved Forecast Revenue requirement[36] with one adjustment as described further in Section 5.1.1.2.1.

Inputs and assumptions included in the COSA include the following:

- The total approved 2017 Revenue requirement was $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 upon which the 2017 approved Revenue requirement was based. The rate base includes mid-year Gross Plant of $1.9 billion, which is offset by accumulated depreciation and customer contributions.
- Average total customers for 2017 of 133,853 and gross energy consumption of 3.3 million MWh.
- The winter system peak is forecast at 761 MW and a peak of 634 MW is expected during the summer months.

[35] The primary Commission Orders approving structural rate changes and rate rebalancing pursuant to the 2009 COSA and RDA are G-156-10, G-196-10, G-24-11 and G-57-11.

[36] October 5, 2016 Evidentiary Update to 2017 Annual Review, Exhibit B2-2.

- Monthly power supply costs were classified as demand-related or energy-related based on the demand and energy charges for electricity supply from BC Hydro under Rate 3808, and allocated on a monthly basis (as described further in Section 5.1.2.2.2 Production/Power Supply Expenses).
- Distribution plant was classified 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.
- Demand-related transmission costs were allocated using the 2 CP (coincident peak) method (sum of 2 winter and 2 summer peaks).

The basic purpose of the COSA 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 of each class. This will inform decisions regarding any rate adjustments or additions required to better reflect the cost of service for each class.

5.1.1 Assumptions and Inputs for the COSA

5.1.1.1 Customer Classes (Segmentation)

Customers are grouped into classes that reflect common usage characteristics or facility requirements.

The main customer classes are as follows:

- Residential
- Small Commercial
- Commercial
- Large Commercial Primary
- Large Commercial Transmission
- Lighting
- Irrigation
- Wholesale Primary
- Wholesale Transmission

As shown above, although FBC serves seven customers at the wholesale level, for rate setting purposes only two Wholesale classes are used – delineated by primary and transmission service connections.

Residential customers make up 86 percent of the total number of customers and over 41 percent of energy sales. Wholesale customers make up another 18 percent of energy sales, with the remaining 41 percent composed of commercial, industrial, irrigation and lighting class consumption.

FBC is not proposing to create any new classes as a result of the current COSA. However, in recognition of emerging trends, FBC has examined customers with Net Metering systems and other partial requirements customers (that is, a self-generating customer that does not rely on FBC for its full requirements at all times) in isolation in order to better understand any differences these customers may have as compared to other customers in the class to which they belong. This is further discussed in Section 3.6.

5.1.1.2 Revenue Requirement

The 2017 Forecast revenue requirement of $362.1 million formed the basis of the 2017 COSA. The 2017 COSA is based on the forecast test year approved for 2017 and has not been updated to reflect any actual costs, sales or revenues for 2017 year-to-date. The use of a forecast year allows for a more standardized basis as it assumes normal weather conditions and stable economic conditions, and does not include any extraordinary costs for the year. COSAs sometimes include adjustments for expected material changes; however, no adjustments of that nature were necessary for the 2017 COSA.

The following summarizes the approved Revenue requirements forecast for 2017 and the one adjustment to the approved Revenue requirements for RS 37 revenues, which is described in section 5.1.1.2.1.

Table 5-1: Revenue Requirement for COSA

Cost Category	Value ($ Millions)
Cost of Energy	152.2
O&M and A&G Expenses	48.2
Return, Depreciation & Taxes	169.8
Less Other Revenue	(8.1)
Net Revenue Requirements	**362.1**
Less RS 37 Revenues[37]	(1.4)
COSA Revenue Requirements	**360.7**

5.1.1.2.1 TREATMENT OF RS 37 REVENUE

FBC has a single customer taking service under RS 37 (Stand-By and Maintenance Service). The RS 37 rates that are used to calculate the revenues of $1.4 million shown in Table 7-1 are

[37] See Section 5.1.1.2.1.

calculated in reference to the hourly Mid-C price in effect when stand-by service is used. These 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 Commission. As these energy sales are made at rates below the fully embedded cost resulting from the COSA, FBC treats the revenues as an offset to the Revenue requirements and allocates them to all customers to compensate for the use of the system which is paid for by all customers (including customers in RS 31 (Large Commercial Service – Transmission), which is the rate schedule also pertaining to a customer taking Stand-by and Maintenance Service). The energy and demand associated with the RS 37 sales are also left out of the RS 31 class amounts and the total system amounts. Other customers are better off having the standby sales because even at a reduced rate, the sales are contributing to the fixed costs of the system. These revenues are allocated to the classes on the basis of the allocated rate base to account for the contribution to recover all fixed costs of the system.

5.1.1.3 Rate Base

The mid-year rate base associated with the 2017 Revenue requirement is $1.28 billion. The rate base includes mid-year Gross Plant of $1.9 billion, which is offset by accumulated depreciation and customer contributions. Distribution makes up 52 percent of Gross Plant, followed by 23 percent for transmission, 12 percent for power production and 13 percent for General Plant. The mid-year rate base is summarized as follows:

Table 5-2: Rate Base for COSA

Cost Category	Amount ($ millions)
Total Gross Plant	1,943.2
Less Accumulated Depreciation	(577.3)
Less Customer Contributions	(112.9)
Working Capital, Deferrals & Other	31.5
Total Rate Base	**1,284.5**

The 2017 rate base of $1.28 billion compares to the 2009 rate base of $0.908 billion. By comparison, the mid-year (2008-2009) rate base reflected Gross Plant of $1.2 billion, also offset by accumulated depreciation and customer contributions. Distribution made up 46 percent of gross plant, followed by 29 percent for transmission, 13 percent for power production and 12 percent for general plant.

The detailed rate base for FBC by account used for the 2017 COSA is in Appendix A – EES COSA Report (Schedule 4.1 of the report's Appendix A).

5.1.1.4 Load Forecast

The total forecast average customer count is 133,853 for 2017 with gross energy consumption of 3.3 million MWh. Residential customers account for 86 percent of the total number of customers and 41 percent of energy sales. Wholesale customers make up 18 percent of energy, with the remaining 41 percent related to commercial and other retail classes.

Table 5-3: Load Forecast

Customer Class	Load (GWh)
Residential	1,353
Commercial	879
Industrial	407
Wholesale	587
Lighting & Irrigation	55
Total	**3,282**

The peak demand forecast used for COSA cost allocations is 761 MW in the winter months and 634 MW in the summer months.

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

5.1.2 COSA Overview

A detailed discussion of the 2017 COSA is contained in the EES COSA Report (Appendix A). This section summarizes the key aspects of the functionalization, classification and allocation exercises undertaken in order to complete the 2017 COSA. As noted in the EES COSA Report, functionalization separates costs into major categories that reflect the utility's plant investment and different services provided to customers, with the primary functional categories being production, transmission, distribution and general. Classification determines the portion of the cost that is related to specific cost-causal factors that are demand-related, energy-related, or customer-related. Allocation of costs to specific customer classes is based on the customer's contribution to the specific classifier selected.

[38] As of March 31, 2013, FBC acquired the utility assets of the City of Kelowna. The City of Kelowna is no longer a wholesale customer of FBC and FBC now serves the former customers of the City of Kelowna directly.

5.1.2.1 Functionalization

5.1.2.1.1 RATE BASE

A summary of the Gross Plant accounts used in the 2017 COSA, and the manner in which they were functionalized is contained in Table 5.4 below.

Table 5-4: Functionalized Gross Plant Summary

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

In addition to the Gross Plant shown in the table above, Rate Base also incorporates the following components:

- Accumulated depreciation (reduction of $577.3 million) - split into Production, Transmission, Distribution and General Plant. Each of the accumulated depreciation accounts was allocated in the same fashion as the corresponding Gross Plant account.
- Customer contributions (reduction of $112.9 million) – the contributions were for items at the distribution level and were assigned to functions on the basis of poles, conductors and transformers.
- Allowance for Working capital (increase of $2.9 million) and plant acquisition adjustment ($3.0 million) - functionalized on the same basis as all operating and maintenance (O&M) costs. Working capital is set aside to cover the time lag between when costs are incurred and when revenue is received from customers. Because O&M and purchased power costs are the primary bills paid by the utility, O&M costs was considered to be a reasonable method for functionalizing and allocating working capital costs. The adjustment for capital additions is similar to working capital was therefore treated in the same manner as working capital.
- Other rate base items (increase of $25.6 million) - separated out by function. The largest item in this category is $12.3 million related to deferred demand-side management (DSM) spending. This DSM amount was functionalized and classified as 72 percent power supply energy, 17 percent power supply demand and 12 percent

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

transmission and distribution. This split is consistent to that used by FBC in the cost/benefit analyses performed for DSM spending.

A summary of the total rate base functionalization is shown in Table 5-5 below.

Table 5-5: Rate Base Functionalization Summary

Rate Base Category	Total	Production	Transmission	Distribution
Hydraulic Production	238.5	238.5		
Transmission	442.8		442.8	
Distribution	1,010.7			1,010.7
General Plant	251.2	70.3	55.3	125.6
Accumulated Depreciation	(577.3)	(92.0)	(148.6)	(336.8)
Customer Contributions	(112.9)			(112.9)
Working Capital, Deferrals & Other	31.5	18.6	4.1	8.8
Total	**1,284.5**	**231.4 (18%)**	**350.1 (27%)**	**703.0 (55%)**

5.1.2.1.2 REVENUE REQUIREMENT

The 2017 Revenue requirement was functionalized as described below:

- Hydraulic Production cost accounts (accounts 535-556), totaling $152.2 million were functionalized 100 percent to Production;
- Transmission cost accounts (accounts 560-567), totaling $18.3 million were functionalized 100 percent to Transmission;
- Distribution cost accounts (accounts 580-598), totaling $10.4 million were functionalized 100 percent to Distribution;
- Customer Service cost accounts (accounts 901-910), totaling $6.5 million were functionalized 100 percent to Distribution;
- Administrative & General cost accounts (accounts 920-933), totaling $13 million were functionalized on the basis of the labour breakdown associated with the three primary functions. This results in $3.6 million to Production, $2.8 million to Transmission, and $6.5 million to Distribution.
- Depreciation expense ($55.7 million) - split by functional areas. Generation depreciation follows generation and so on. Depreciation for General Plant and deferred charges follows the treatment of the General Plant, which in turn is based on the Gross Plant before General Plant. DSM amortization follows the DSM rate base account.
- Return ($87.2 million) and Income tax ($10.8 million) - functionalized on the same basis as the total rate base.

- Property taxes ($16.1 million) - related to the value of FBC's assets and are therefore treated in the same manner as the total system net plant.
- Other Revenues (a credit of $8.1 million) - revenues from other activities, such as pole attachment fees. Other revenues of FBC are treated as an offset to the Revenue requirement. Other revenues are therefore credited back to customer classes in a manner that is consistent with the specific other revenue line item.
- RS 37 Revenue (a credit of $1.4 million) – all customers on the system pay for the facilities used to provide this service. For the 2017 COSA FBC treats these revenues as an offset to the cost of service since the revenues provide a partial recovery to the fixed costs of the system. These revenues are allocated to the classes in proportion to the allocated rate base.

The sum of these items is equal to the total Revenue requirement shown in Table 5-6.

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

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

5.1.2.2 Classification

The second step in performing a COSA is to classify the functionalized expenses to cost-causation categories. These cost-causation categories can be directly related to specific consumption behavior or system configuration measurements such as coincident peak (CP) or non-coincident peak (NCP) demand, energy, or number of customers. Each classification category will have a specific allocator that, when applied, will distribute those costs among the appropriate customer classes during the allocation phase of the analysis.

The three primary classifiers are:

- Demand

- Energy
- Customer

Functionalized power supply costs are generally split between demand-related and energy-related. Transmission system costs are generally classified as demand-related. Distribution costs are generally split between demand-related and customer-related components, or directly assigned to a specific customer class.

5.1.2.2.1 RATE BASE

A summary of the classification of the rate base is found in Table 5-6 below. A more detailed discussion of this process can be found in the EES COSA Report attached as Appendix A.

Table 5-7: Rate Base Classification

Description	Classified to:		Note:
Production	20% Demand 80% Energy		On the basis of the demand / energy split for equivalent BC Hydro 3808 Purchases
Transmission	100% Demand		
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]	

With respect to the classification of Production, the output from the Kootenay River plants was treated as if it were purchased at the BC Hydro 3808 rate to determine the split in costs between demand and energy. This split was then applied to actual costs of the Kootenay River plants for purposes of classification. The resulting split was roughly 20 percent demand-related and 80 percent energy-related. This approach was first used in the 2009 COSA and was accepted by the Commission. A more detailed discussion of this method can be found in the EES Consulting report at page 23.

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

As noted in Table 5-7, Distribution costs were split between demand and customer according to a minimum system approach. This approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory, 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 concept follows that any costs associated with a system larger than this minimum size are due to the fact that customers "demand" a delivery quantity greater than the minimum unit of electricity and that therefore, those costs should be treated as demand-related,

While the minimum system is, in theory, designed to carry only a minimal amount of load, the actual facilities designated as the minimal size are actually capable of carrying some amount of demand. The actual amount of demand capability within the minimum system is a function of load density, minimum required clearances, minimum equipment standards, temperature, and other engineering considerations. Using only the minimum system allocation technique, each customer/connection attracts an equal allocation of the minimum system, plus each customer class is allocated demand costs based on the total customer class' non-coincident peaks. As such, it has been argued that a customer class' non-coincident demand allocator is too large, because a portion of these peak demand-related costs is being covered through the per customer/connection minimum system allocation.

The correction of the problem of over allocating demand can be achieved by the application of a Peak Load Carrying Capability (PLCC) adjustment. This adjustment was first introduced in the 2009 COSA. The precise amount of a PLCC adjustment should match the definition of the minimum system adopted. In the FBC case, it was determined that the average PLCC for the FBC system is 1.09 kW per customer. Appendix B to the EES Consulting Report provides a more detailed discussion of the PLCC and how the amount was calculated.

In addition to those shown in Table 5-7, there are number of other, small Rate Base items included in the classification process. These are as follows:

- **General Plant** - after being functionalized to the three areas shown in Table 7-6 above, General Plant was classified using the resulting classification as total rate base for each function. For example, the 26 percent of General Plant assigned to generation was split between demand and energy in the same manner as the generation rate base.
- **Accumulated depreciation accounts and working capital** accounts - classified in the same fashion as the corresponding Gross Plant accounts. Customer contributions were assigned to classes on the basis of poles, conductors and transformers.
- **Plant acquisition adjustment and deferred costs** - classified on the same basis of Gross Plant prior to General Plant.
- **Construction Work in Progress (CWIP) not earning Allowance for Funds used during Construction (AFUDC)** - assigned to each function and classified in the same manner as the rate base for each function.

- **DSM** - classified as 72 percent power supply energy, 17 percent power supply demand and 12 percent transmission and distribution demand. This split is consistent to that used by FBC in the cost/benefit analyses performed for DSM spending.

5.1.2.2.2 PRODUCTION/POWER SUPPLY EXPENSES

Classifying power supply costs to demand and energy components depends on the use of the generation and the pricing for power supply purchases. For FBC, the power supply resources include FBC-owned generation, long-term power purchase contracts including a tariff-based purchase from BC Hydro, and a small amount of market purchases. All of the resources used by FBC have both an energy and peaking component to them.

Table 5-8: Production / Power Supply Expense Classification

	2017 Costs ($ Millions)	Classification	Notes
Kootenay River Plants	$16.0	20% Demand 80% Energy	On the basis of Generation Rate Base
Columbia Power Corporation (Brilliant) and Waneta Expansion	$81.0	31% Demand 69% Energy	Using BC Hydro 3808 as a proxy each month
BCH 3808 Purchases	$49.0	20% Demand 80% Energy	As Charged
Net Market Purchases	$6.2	100% Energy	All Energy Purchases
Total System	$152.2	27% Demand 73% Energy	Sum of all Resources

5.1.2.2.3 OTHER EXPENSES

There are a number of additional expense categories that require classification. This section of the Application summarizes those cost areas and how they are treated within the COSA.

- Transmission Services - FBC purchases wheeling services from BC Hydro in the Okanagan and Creston areas to supplement its own transmission. The cost of providing transmission service to a customer is considered to be directly proportional to the demand that customer imposes on the system. All transmission expense accounts are classified on the same basis as transmission rate base.
- Distribution Expenses - Many of the distribution expense accounts correspond to a rate base account and follow the treatment of the rate base item. For example, account 583.10 is for distribution line maintenance, corresponding to rate base account 365-conductors and devices. Since the distribution rate base uses a minimum system approach, the expenses will also follow the splits resulting from that analysis. Street lighting expenses are directly assigned to the lighting class. Account 598 – other distribution plant is classified on the basis of total distribution rate base.

- Customer Service Expenses - all classified as customer-related.
- Administrative and General Expenses - first assigned to each function on the basis of labour ratios. These amounts were then classified on the same basis as the rate base for each of the three functions (transmission, distribution, and production).
- Depreciation Expense - assigned to each function following the rate base for that function.
- Return accounts are all classified on the same basis as the total rate base.
- Property taxes are related to the value of FBC's assets and are treated in the same manner as the total system net plant.
- Other revenues are credited back to customer classes in a manner that fits the specific revenue item.

5.1.2.3 Allocation

The third step in performing a COSA is the allocation of the utility's total functionalized and classified Revenue requirement to the customer classes of service. This is performed through the application of an appropriate allocation methodology.

A broad discussion of the allocation factors considered for FBC and the rationale for selecting the factors ultimately used is contained in the EES COSA Report (Appendix A of the Application). A basic summary of the allocators used in the 2017 COSA is below. The information in the table shows, for example, that those rate base items, that have been classified as demand related, are allocated using the 2 coincident peak methodology, and so on.

Table 5-9: Rate Base Allocation Summary

Function	Classification	Allocation Method
Generation Rate Base	Demand Related	2 Coincident Peak
	Energy Related	Annual Energy Use
Transmission Rate Base	All	2 Coincident Peak
Distribution Rate Base	100% Demand Related Components	Non-Coincident Peak Primary
Distribution Rate Base	Split between Demand and Customer components	Non-Coincident Peak Primary Non-Coincident Peak Secondary Number of Customers
Distribution Rate Base	100% Customer Related Components	Customers weighted according to the average cost of meters by class
Distribution Rate Base	Street Lights & Signal Systems	Direct Assignment
Distribution Rate Base	General Plant	On the same basis as was used for each of the classified components

Function	Classification	Allocation Method
Distribution Rate Base	Accumulated depreciation	On the same basis as the corresponding Gross Plant accounts
Distribution Rate Base	Working capital	On the same basis as all O&M costs
Distribution Rate Base	Customer contributions	On the same basis as poles, conductors and transformers

The Revenue requirement is allocated in a similar manner as the rate base. Allocation of the Revenue requirement results in costs settling to the individual customer classes. In sum, the allocated Revenue requirement by customer class can be compared to the anticipated revenues by customer class in order to make an assessment of the extent to which each class is expected to provide revenues sufficient to cover its cost to serve. A summary of the main allocation factors is provided in the table below. Additional allocation factors are discussed in the EES COSA Report.

Table 5-10: Revenue Requirement Allocation Summary

Function	Component	Allocation Method
Power Supply	Demand Related	Contribution to system peak (by month)
	Energy Related	Energy Use (by month)
Transmission Expense Accounts	All	2 Coincident Peak
Distribution Expense Accounts	All Except Lighting	On the same basis as the corresponding rate base account
	Lighting	Directly Assigned to customer classes
Customer Service Expenses	Supervision and Administration	Allocated using the ratio of all other Customer Service Expenses for the class to total Customer Service Expenses
	Meter reading, customer billing and customer assistance	Customers weighted for accounting/metering.

5.2 REVENUE/COST RATIOS – THE RANGE OF REASONABLENESS

The revenue to cost (R/C) ratio for each customer class is calculated by dividing the revenue at current rates by the total allocated costs. The approved 2017 Revenue requirement includes revenues calculated using an average rate for each class, consistent with the method used in past years. For purposes of the COSA, revenues were calculated under each tariff based on the billing determinants for each class.

Using the revenues at approved rates for the 2017 Evidentiary Update and adding the allowed 2017 rate increase results in projected revenues of $362.1 million. The calculated revenue from rates in the COSA using the actual billing determinants times the various rate components is

$362.0 million, which is 0.38 percent lower than the revenue requirements provided in the Evidentiary Update.

Since the expected revenues derived from billing components and forecast load differ slightly from the approved revenues from FBC's 2017 Annual Review, an adjustment is made on a pro-rated basis to ensure that total allocated revenue divided by total allocated costs is equal to unity. The resulting R/C ratios help inform the need for revenue rebalancing. Revenue rebalancing is the method by which the utility shifts revenue responsibility from one customer group to another.

The R/C ratios in the 2017 COSA are shown in the following table.

Table 5-11: COSA Revenue to Cost Ratios

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

R/C ratios are assessed based on whether or not they fall within an established range of reasonableness (RoR). As cost allocations in a COSA necessarily involve assumptions, estimates, simplifications, judgments and generalizations, a RoR is warranted and is a widely accepted practice used to evaluate the appropriateness of the R/C ratios, and whether revenue rebalancing is warranted.

The result of the COSA for each rate schedule is considered in light of this RoR and each rate schedule that falls within that range is deemed to be recovering its fair cost. If a rate schedule falls out of the RoR, this indicates that revenues are either insufficient to cover the cost of service or exceed the cost of service, which suggests that rate rebalancing may be in order. The RoR is therefore used as an indication of the rate schedules that require rebalancing. As a separate consideration, even if all of the rate schedules fall within the RoR, some re-balancing may be necessary in light of rate schedule characteristics and rate design objectives.

The appropriate RoR depends on the particular circumstances of a utility. Recent Commission decisions suggest that a RoR of 95 percent to 105 percent is appropriate for electric utilities in British Columbia. Specifically:

- In Order G-130-07 in response to BC Hydro's 2007 Rate Design Application, the Commission determined that a "RoR of 95 per cent to 105 per cent [was] the correct range for the purpose of future rebalancing in the circumstances of BC Hydro."[41] The rationale for the decision was based in part on the "the known system demand and demand metering of large commercial and industrial customers" and "the accuracy of the relatively sophisticated load research analysis."[42] As a result, the Commission panel determined for BC Hydro "that the appropriate target R/C ratio in each class is unity or one and that future rebalancing should only be required when a customer class falls outside of the RoR."[43]
- Similarly, in the October 2010 Decision on FBC's 2009 COSA and RDA, the Commission found that "the appropriate RoR of 95% to 105% is the correct range for the purpose of future rebalancing in the circumstances of FBC."[44] As in the BC Hydro decision, the Commission determined the appropriate target R/C in each rate schedule to be one, with future rebalancing necessary only when customer classes fell outside the range. The Commission also accepted FBC's position that the RoR is "based not only on the accuracy of its data, but also on policy considerations such as the Commission's prior decision regarding the RoR for BC Hydro."

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

5.2.1.1 Rate Rebalancing

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

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

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[41] Commission Decision and Order G-130-07, dated October 26, 2007, page 71.
[42] *Ibid*.
[43] *Ibid*.
[44] October 2010 Decision, page 77.
[45] *Ibid.*, page 78.

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

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

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

6. RATE DESIGN

Each customer class has a rate schedule under which a customer would normally take service in the absence of an election to subscribe to an available optional rate. This "Default Rate" is discussed for each class of customers in this section of the Application. Below, FBC reviews the current Default Rate structures of its customer classes, discusses any issues with the current design and advances any proposals for changes recommended by the Company.

Where an optional rate also exists, this is reviewed after the Default Rate discussion. The exception to this general review of the rates is the discussion of Time-of-Use rates, which due to the comprehensive redesign of these optional rates, they are discussed separately in Section 8 of the Application.

6.1 *RESIDENTIAL RATES*

Generally speaking, the rates covered in this section are for residential services as defined in FBC's Electric Tariff GT&Cs.

Typically, residential service is for use at residential premises. A residential premise includes single family dwellings supplied through the same meter, as well as single or individually metered single-family townhouses, rowhouses, condominiums, duplexes or apartments, carriage houses, farm buildings, or manufactured homes.

In the 2017 COSA, there was approximately 117,000 customers that accounted for 87 percent of total customers and approximately 40 percent of energy sales.

6.1.1 Current Default Residential Rate

At the present time, the residential Default Rate is **Rate Schedule 1 – Residential Service (RS 01), commonly known as the Residential Conservation Rate or "RCR")**: This rate is an inclining block rate and includes four components:

a) **Customer Charge –** a fixed charge that occurs each Billing Period[46] and that remains constant regardless of the customer's consumption.

b) **Threshold** – The Threshold represents the maximum number of kWh that a customer may consume during a Billing Period that will be billed at the Block 1 Rate.[47]

c) **Block 1 Rate** – The rate at which energy consumed during a billing period, up to and including the number of kWh represented by the Threshold, is billed.

[46] The term Billing Period may mean a period of "one month" which normally means the time elapsed between the meter reading date of one calendar month and that of the next, or a "two-month period" which normally means the time elapsed between the meter reading date of one calendar month and the second following calendar month.

[47] Both the Customer Charge and the Threshold may be prorated if the event that the number of days over which the bill is calculated falls outside of the range determined by Section 6.2 of the Electric Tariff.

d) **Block 2 Rate** – The rate at which all kWh consumed above the Threshold level of consumption during a Billing Period will be billed.

The 2017 RS 01 rate is as follows:

Table 6-1: RS 01 Rate Components

Rate Element	Monthly Billing Period	Bi-Monthly Billing Period
Customer Charge	$16.05	$32.09
Threshold (kWh)	800	1,600
Block 1 Rate (per kWh)	$0.10117	$0.10117
Block 2 Rate (per kWh)	$0.15617	$0.15617

6.1.2 Current Optional Residential Rate

The Company maintains a residential rate with a Customer Charge and flat energy charge component for customers that fall into one of two categories:

1. Customers enrolled in FBC's Residential Conservation Rate (RCR) control group (RS 03), and
2. Eligible farm customers as set out in the requirements under FBC's Electric Tariff (RS 03A).

RS 03 and RS 03A represent the residential flat rate that would be in effect if the RCR had not been implemented in 2012. The 2017 rate components are as follows:

Table 6-2: RS 03 and RS 03A Rate Components

Rate Element	Monthly Billing Period	Bi-Monthly Billing Period
Customer Charge	$18.70	$37.39
Energy Rate (per kWh)	$0.11749	$0.11749

The Company is requesting approval to remove RS 03 that refers to the RCR control group from the Electric Tariff. The RCR control group was dissolved in 2015. FBC last filed an RCR summary report to the Commission in 2014 and there are no further Orders establishing an ongoing requirement to provide reports on a regular basis.

6.1.3 Default Rate Discussion

The RCR was the dominant topic of discussion during the public consultation activities related to the 2017 COSA and RDA. It has also been the subject of a number of FBC reports filed with the Commission. The issue of residential inclining blocks for both FBC and BC Hydro was the subject of a Commission-led process in 2016. That process resulted in the British Columbia Utilities Commission Residential Inclining Block Rate Report to the Government of British

Columbia (BCUC RIB Report) and the subsequent BC Government letter to FBC requesting that alternatives be considered in FBC's future rate design.

Given the public awareness and sentiment within certain customer groups toward the RCR, as expected the segment of customers that perceive their annual electricity costs to be higher under the RCR than under an equivalent flat rate was well represented at the various open houses conducted by FBC. FBC's experience with responding to customers who contact FBC individually with this concern has shown that this perception is not always reflective of an actual comparison of flat rate versus RCR billing over the course of a year. Customers may fail to account for lower bills during the lower consumption months or for the increase in the level of rates generally. However, it is the case that approximately 30 percent of residential customers receive higher annual billings under the RCR than would be the case under the flat rate and approximately 70 percent of customers receive lower annual billings than would be the case under an equivalent flat rate. The magnitude of the difference generally increases with annual consumption, whatever the cause. The impact of the RCR is contained in the BCUC RIB Report.[48]

During the first series of public consultation open houses held in June 2017, the Company reviewed COSA and rate design concepts with attendees in an effort to better equip customers to provide input into the process. At those sessions, the Company also received feedback on the current rate structures and options for addressing issues that customers felt were inherent in the rate structures as they currently exist.

The predominant sentiment at the sessions was that the RCR was unfair and punitive, particularly to those customers that had either exhausted their opportunities for conservation, or had few opportunities for conservation given their individual circumstances (for example: dwelling type, number of occupants, or income). Access to natural gas continues to be a concern for a number of customers due to the inability to change to a less expensive fuel for two of the higher contributors to overall energy use – space and domestic hot water heating. FBC considers that the various objections to the RCR are well documented in the BCUC RIB Report.

6.1.4 Residential Rate Options

The public consultation activities, including the June open houses and the online feedback tool provided a number of residential rate options that were either suggested by participants or raised by the Company for consideration. These options were:

- 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;

[48] The BCUC RIB Report and associated filings are available on the Commission's website. http://www.bcuc.com/ApplicationView.aspx?ApplicationId=506

- 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.

At its second set of consultation sessions in late July 2017, the Company presented and discussed these options for adjusting the default residential rate, if changes were found to be necessary.

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.

FBC also presented a number of "Guiding Principles" to be considered when specifically examining rate options for the residential customer class. In its 2011 Application for Residential Inclining Block (RIB) Rates, FBC suggested that a constraint on annual bill impact be considered in evaluating rate options. The RIB rate ultimately set by the Commission met the standard that 95 percent of customers should have bill increases no greater than 10 percent as compared to existing rates.

For the 2017 RDA, FBC has ensured that, at a minimum, this same constraint for evaluating rate options was in place. However, since a phased-in approach to rate changes has also been evaluated whereas the original constraint was on a year over basis, in the FBC proposal presented in Section 6.1.5, no customer will experience an annual rate increase greater than 3.5 percent[49].

Other principles considered are as follows:

- Recovery of cost of service (neutral to current rates);
- Cost-based;
- Easy to understand and administer;

[49] Based on 2016 consumption

- Address customer concerns; and
- Promote conservation.

These "Guiding Principles" are supplementary to (or particular illustrations of), and not intended to replace or diminish, the Bonbright-based general FBC "Rate Design Principles" that were included in FBC's June presentation and are listed in Section 3.2 of this Application.

While FBC heard during consultation that balancing the interests of all customers is also important to individuals, it is also the case that customers tend to look at their particular circumstances when evaluating options placed before them.

FBC is in agreement with the customer sentiment that the impact of the RCR has become overly burdensome on high consuming customers, but also notes that the BCUC has determined that it does not find that the RIB rate causes a subsidy between customers in areas with and without access to natural gas.[50]

It is evident from the analysis of the rate options that a particular spectrum of billing impacts can be arrived at for almost any of the options. In other words, a very similar billing impact can result from either raising the Tier 2 Threshold and adjusting the other rate elements accordingly, or leaving the Tier 2 Threshold alone and making different changes to the other rate elements.

FBC does not suggest that seeking a particular set of bill impacts is the goal of rate design, but as a consideration, similar sets of aggregate bill impacts can be accomplished in a variety of ways.

As the bill impact information in this section is reviewed, it is useful to consider that primary among the metrics used by both the Company and the customer to evaluate the impact of any change in the structure of the default rate is the impact on annual bills as compared to those generated under the existing RCR. For FBC, attention must be paid to the impact on all customers or groups of customers with similar consumption habits and a balance is sought between acceptable bill increases that must result for some if the impact of the RCR on other customers is reduced.

In the following sections, FBC reviews each of the rate options listed above except for two, the Optional TOU and the variation in the Customer Charge. The review of Optional TOU is contained in Section 8 of the Application, and specific treatment of the Customer Charge is a component of the various options considered.

[50] BCUC RIB Report, page 9.

6.1.4.1 No Natural Gas Access Rate

A specific rate available only to customers that do not have access to piped natural gas service was raised by participants in the public consultation sessions and was also included as a suggestion in a number of submissions to the Commission in its RIB Report process.

The Company did not model any particular "no-gas" rate as part of its analysis both because such a rate is not appropriate as discussed further below, and that rate mitigation for high consuming customers that fall within this group can be addressed by making changes to the RCR that impact all customers with similar consumption in a similar manner.

Certain customers have expressed that the absence of natural gas service means that a less expensive means (as compared to electricity) of providing space and water heating is unavailable. This leads to higher than average consumption, which in turn leads to higher bills. These customers maintain that since some customers have access to natural gas and can take advantage of the more economical means of heating, while others cannot, a situation of inequity is created which can be characterized as unfair and discriminatory. The situation is further described by the following example of a submission received by FBC during the comment period leading up to this Application.

> We live on xxxxxxxxxxxxxx and do not have access to natural Gas in order to heat our homes in the winter.
>
> Our electricity bills go from a low in the Summer months of $98 to $900 in the winter months. We have a business in town so we are not at our home for 5 days during the week, in the winter we turn the thermostat down to 15C and when we get home turn it up to 18/19 C and layer up yet our bill is $900.
>
> Of course most of that bill is in the two tier rate because we do not have access to natural gas - we feel that this is completely discriminatory as we have no other choice.
>
> While we could put in wood burning stove this is not the way to go because of the environment.
>
> We are suggesting that we go to a flat rate instead of this unacceptable two tier system which results in these astronomic bills.
>
> The house is new, well insulated and operates with energy saving appliances - what more can we do to reduce consumption - Nothing.

The Company agrees that as a group, customers that do not have natural gas service, whether as a result of the lack of gas delivery infrastructure or as a matter of choice, will have an average annual electrical consumption that is higher than residential customers in general. This is also a factor in higher than average annual bills.

However, the Company is not proposing to implement a rate that is available only to customers without access to natural gas. FBC sees a number of problems with a "no access to gas rate", further described below, and that relief from the impacts of the existing structure of the RCR is better addressed by FBC's recommended rate option described in Section 6.1.4 of this Application.

6.1.4.1.1 NO BASIS IN COST CAUSATION

The principle of cost causation is a foundational consideration in rate setting. While it is the case that the analysis performed in order to provide the Company's submission in the BCUC RIB Report process indicated that "no-gas" customers had a slightly higher revenue to cost ratio than customers in general, this was due to higher than average revenues and an atypical load profile as opposed to any significant difference in the cost to serve. In addition, it is expected that these factors would be similar to customers that have access to gas, but do not choose to use it. The Commission examined this issue of cross-subsidization as part of the BCUC RIB Report and found no basis to conclude that a cross-subsidy exists. This is not inconsistent with FBC's earlier statement that the group of customers without gas service has higher average annual bills owing to their higher than average consumption.

In addition, there is no justification for singling out the no-gas group for a special rate when there may be a number of factors, such as geography, seasonality, or demographic attributes that, when examined in isolation, may demonstrate a similar apparent intra-class cross-subsidization. Postage stamp rates in general will result in some intra-class subsidies. This does not mean that separate rate classes, or subdivisions within a particular rate class, should be pursued. FBC supports the postage stamp rate concept where all customers with substantially similar characteristics are billed on the same rate.

Many of the customers that advocate for a no-gas rate indicate that environmental impact is an important consideration and that the RCR may result in the increased burning of wood for domestic heat. However, where a customer that has access to natural gas chooses, for environmental reasons, to use electricity for its lower GHG emission impact, they would be faced with a higher rate should a no-gas rate be implemented. This is a situation to be avoided.

In addition, in their assessment of natural gas space and water heating being less expensive than using electricity for these end uses, advocates of a rate for "no gas access" may not be considering all of the costs associated with having natural gas service. While the monthly natural gas bills for space or water heating might be lower than the corresponding electricity bills for equivalent thermal energy service, the upfront installation costs of having natural gas space and water heating are higher than for electricity for components such as furnaces and water tanks, as well as for in-house piping, ducting and venting. Natural gas equipment typically also has higher annual maintenance costs than the corresponding electrical equipment. When these other costs are considered the life cycle cost differences between the cost of natural gas and electricity for space heating are reduced.

6.1.4.1.2 Rate Not Discriminatory

The issue of whether or not the RCR is a rate that causes a cross-subsidy was examined in the BCUC RIB Report process. In this regard, the Commission stated that it had,

> …received a number of comments from the public suggesting alternative implementations of the RIB rates, such as different rates for areas without access to natural gas (see Appendix A, sections 1.2 and 1.6). While the subjects of revenue neutrality and alternative rate structures are specifically out of scope for this review, the Commission notes in the earlier part of this section that it does not find that the RIB rate causes a subsidy between customers in areas with and without access to natural gas, and hence there is no compelling reason to consider restructuring the RIB rate on that basis.[51] [Emphasis added]

6.1.4.1.3 Difficulty in Administration

During the public consultation sessions, some customers expressed the view that with FBC and FEI being the distributor of both electricity and natural gas in the combined service area, it should be a simple matter to identify electric customers that do not have access to gas. While it may seem a relatively simple task to identify customers that may be eligible for a no-gas rate, in reality, there are a number of administrative obstacles that would need to be overcome and that do not exist with the current rate structure.

First, a definition of what constitutes "access to natural gas" would need to be developed. It is obvious that communities such as Kaslo or South Slocan, where the entire area lacks gas service can be captured. Other communities, such as Oliver and Osoyoos, cannot be identified as such given that portions of the communities have access to gas while other portions do not.

This raises a further difficulty. How does one define access to gas where service may be close by, but not in front of the premise? This then becomes a financial question, since access can be gained for a particular cost.

These issues could likely be overcome, but would require ongoing monitoring to maintain an accurate delineation of where gas availability may change over time, and would ultimately provide no assurance that a customer without gas service would choose to heat with wood while also enjoying the benefit of a lower rate.

Based on these considerations a no access to gas rate would come with costs that are all incremental to both the current rate structure and the option ultimately proposed for implementation.

[51] BCUC RIB Report, page 9.

6.1.4.2 Changes to the Existing RCR

The four rate elements of the RCR (the Customer Charge, Tier 1 Rate, Tier 2 Rate and Threshold) can all be varied provided that, given the forecast billing determinants, they will result in revenue equivalent to the forecast residential revenues under the current rates.

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

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

The rate options were analysed while also incorporating an increase in fixed-cost recovery across all rate classes, as discussed in Section 3.4 of this Application. As a result, FBC did not present options where the Customer Charge was reduced. It is a function of the fixed nature of the Revenue requirement that a decrease in the Customer Charge will result in an overall increase in the variable energy charges included in the rate.

A seasonal RCR variant was also discussed at the sessions. The premise of this option is that the Threshold would be increased during the winter when consumption typically increases in order to provide customers with more consumption billed at the Tier 1 rate. This option was not modelled since it cannot be accommodated without significant and costly changes to the billing system, and more importantly, does not provide bill mitigation that cannot be accomplished through the other options that were explored.

Table 6-3 is a reproduction of the results presented in Slide 25 of the July open house presentations for a number of RCR options (using the option numbers from that slide). The flat rate and declining block options which were also canvassed have been removed for presentation here as they are not RCR options. Note that the percentage of customers with bill impacts greater than 10 percent, although shown in the last line of the table, cannot be derived from the table itself because the table aggregates customers on the basis of consumption rather than bill impact.

Changes within the options (referring to the option numbering in the top row of Table 6-4) are summarized below.

Table 6-3: Options for Changing RCR Components

Option	Customer Charge	Tier 1 Rate	Tier 2 Rate	Threshold
Option 3	Unchanged	Increased	Decreased	Increased
Option 4	Increased	Increased	Unchanged	Increased
Option 5	Unchanged	Increased	Decreased	Unchanged
Option 6	Increased	Increased	Decreased	Unchanged
Option 7	Increased	Increased	Decreased	Unchanged
Option 8	Increased	Increased	Decreased	Unchanged

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

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

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

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

Of the options presented in Table 6-4, those labelled 6, 7, and 8 would meet all of these criteria. Option 8 would come closest to having the Customer Charge set at a minimum of 55 percent of the COSA unit cost. FBC was open to having this preliminary conclusion informed or altered based on the input received through the consultation process that was ongoing at the time.

6.1.4.3 Declining Block Rate

The Company modelled a sample declining block rate in response to a customer request, though FBC does not support the implementation of such a rate and did not receive any supporting comments from consultation participants. This option was not explored in further detail or seriously considered given that it may discourage conservation and offers no advantage over the options considered.

6.1.4.4 Changes to the Customer Charge

Changes to the existing Customer Charge were discussed during consultation activities, where FBC explained that the Customer Charge could be maintained at its current level, increased or decreased; however, reducing the Customer Charge would exacerbate the issue of inadequate fixed cost recovery and this option was not considered.

In examining a change in the Customer Charge, a logical change is to align the current RS 01 Customer Charge to that of the Exempt Residential Rates (RS 03 and RS 03A), currently $18.70 per month. At $18.70, the Customer Charge collects 53 percent of the associated fixed COSA charges. This is just below the target of 55 percent, but as this is the change discussed during consultation no additional increase is being proposed. There is no cost-based rationale for having the Customer Charges of the two residential rates differ.

An increase in the RCR Customer Charge from its current level of $16.05 per month to $18.70 requires a reduction in the overall revenue recovered from the Tier 1 and Tier 2 Energy Charges in order to maintain revenue neutrality to current rates. The Tier 1 and Tier 2 rates must be adjusted in order for this to occur. In the analysis that follows, FBC has set the Tier 1 and Tier 2 rates such that the overall residential revenue recovered is the same as under current rates, and the differential between the Tier 1 and Tier 2 remains as it is today. This results in a rate as shown in Table 6-5.

Table 6-5: RCR with RS 03 Customer Charge

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

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

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

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

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

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

As part of the analysis of an increase to the Customer Charge, FBC also examined the impact of phasing in the increase such that the RS 01 and RS 03 Customer Charges were equivalent after five years.

Using the same assumptions regarding the Tier 1 to Tier 2 differential and revenue equivalency, and assuming that rates become effective on January 1 in each year, rates would be as shown in Table 6-7 below. The Customer Charge increase has been spread evenly over the 5 years.

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

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

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

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

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

6.1.4.5 Return to Flat Rate Billing

Many consultation participants supported a return to the flat rate structure similar to the one in use as the default rate prior to implementation of the RCR.

The options of matching the RS 03 Customer Charge, as well as increasing the Customer Charge under a flat rate, along with annual bill impacts as compared to the status quo RCR were presented at the July open houses.

In Table 6-8 below, FBC shows the additional option of maintaining the existing RS 01 Customer Charge at its current level so that the impact of moving to a flat rate in a single change can be examined in isolation.

In order to collect the residential revenue requirement in this scenario, the flat energy rate would need to be set such it would recover the same revenue as collected by both the Tier 1 and Tier 2 rates of the RCR. Given the forecast residential energy sales in the 2017 COSA, this energy rate would be $0.1202 per kWh.

Table 6-8: Bill Impact of Flat Rate Options

Option		Flat Rate Option	
Customer Charge (currently $16.05)		$16.05 per month	
Tier 1 Rate (currently $0.10117 /kWh)		$0.12021 /kWh	
Tier 2 Rate (currently $0.15617 /kWh)			
Annual kWh	**Percent of Customers**	**Average %**	**Average $**
Above 35,000	2%	**(17%)**	**(1,494)**
30,000 – 35,000	1%	**(13%)**	**(631)**
25,000 – 30,000	2%	**(12%)**	**(451)**
20,000 – 25,000	5%	**(9%)**	**(273)**
15,000 – 20,000	10%	**(4%)**	**(98)**
10,000 – 15,000	22%	**4%**	**64**
5,000 – 10,000	37%	**12%**	**118**
0 - 5,000	21%	**11%**	**55**

* Mean annual consumption for the sample is 10,800 kWh/year

Changing the default rate to a flat rate over the course of a single year will generally result in significant adverse annual bill impacts for lower than average consumption customers and overall would result in some degree of bill impact for over 70 percent of customers. Since FBC has no data that indicates that low-income customers have consumption that varies from customers in general, it follows that similar bill impacts will occur within the low income groups as well. This is the situation for both of the options shown above although the distribution of impact is different. As such, a return to a flat rate in a single year would violate the principle that 95 percent of customers should not experience an annual bill increase greater than 10 percent.

Therefore, FBC is not proposing to return to a flat rate over a one year period. However, FBC has explored further a phase-in to a flat rate.

If a return to a flat rate for the default residential rate were phased in over a 5 year period in a manner similar to that discussed for the Customer Charge, annual bill impacts can be mitigated.

In Table 6-9 below, the phase-in has been accomplished by reducing the differential between the Tier 1 and Tier 2 rates in equal annual increments from its current level of 54.5 percent to zero percent by year five.

The resulting rates and annual bill impact results are as follows.

Table 6-9: Transition of RCR to Flat Rate

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

6.1.5 Default Residential Rate Recommendation

The FBC proposal for the Default residential rate is a phased-in return to a flat rate for all customers, accompanied by a harmonizing of the Customer Charges of RS 01 and RS 03 at the RS 03 level.

While it would be possible to implement the Customer Charge increase and return to the flat rate structure independently, FBC believes that its proposal to do both concurrently best adheres to the principle of cost causation while mitigating any negative bill impacts for customers.

This recommendation is driven by the following considerations.

FBC has stated in the past that since the RCR is designed to be revenue neutral to the otherwise available flat residential rate, which is based on the 2009 COSA and RDA, the rate itself can be considered to be cost-based. In effect, the portion of total revenue derived from the energy and customer charges is roughly the same as would exist had the flat rate been the default rate since the RCR came into effect.

However, there is no cost basis for the current levels of the Tier 1 and Tier 2 rates that form the RCR, nor for any particular threshold and tiered pricing. These rates were initially set to achieve a desired result (lower residential class energy use) within a constraint linked to the annual bill impact of customers. There is no particular relationship between the level of the existing rates, and any operational or cost basis.

The lack of a cost basis for the existing RCR is the primary driver behind the Company's proposal to return the default residential rate to a flat structure.

The FBC proposal, for a harmonizing of the RS 01 and RS 03 Customer Charges, and the flattening of the Energy Charge, will better align the rate with COSA unit costs. The FBC proposal will help to improve the intra-class fairness since low use customers, who currently benefit from the lower Customer Charge at the expense of higher consuming customers, would pay a more equitable share of the fixed costs they impose on the system.

In addition, customers have expressed that over the past five years, most of the steps available to reduce the impact of the RCR on billing have been taken. The conservation achieved to date is now embedded in the forecast residential load. Additional conservation is likely subject to diminishing returns and continuing with the RCR into the future not only lacks a cost basis, but may create inequity amongst customers with regard to the ability to take steps to reduce consumption. This conclusion is also consistent with the assumption made during the original 2011 RIB process where the total rate-related conservation impact was assumed to be fully realized over 5 years, or by 2017.[52]

With respect to other rate design principles and objectives, when considered alongside the current inclining rates, 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. For example, customers have indicated that in order to reduce bills associated with the winter heating season, burning firewood has become a viable alternative.

For these reasons, FBC believes that now is the time to begin to transition the residential customer class back to a flat rate. Given the potential for adverse bill impacts that an immediate transition would entail for lower consuming customers, the Company is proposing to effect the transition over the course of 5 years. At the end of this timeframe, the default residential rate and the existing exempt rate will be the same. At that time, the exempt rate will no longer be necessary and residential customers will be billed on a flat rate, unless customers choose to participate in FBC's proposed optional TOU rate.

[52] Refer to the response to BCUC IR 2.3.1.1 in the 2011 FBC RIB Application (Exhibit B-12).

A forecast of the rates and annual bill impacts of both the move to a higher Customer Charge and a phase out of the RCR over the transition period are shown in Table 6-10 below.

Table 6-10: FBC Residential Rate Proposal

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

The annual bill impacts for all consumption levels are moderate, with no consumption group having an annual average increase in excess of $42 in any year, and no customers experiencing an annual bill increase in excess of 3.5 percent.

Though the average annual bill impacts are less dramatic under the phase-in proposal as opposed to a single year return to a flat rate, it is still the case that each year, approximately 75 percent of customers will experience an annual bill increase as compared to the rate in effect the previous year. This is consistent with FBC's conclusion in the most recent RCR Report it filed with the Commission (2012-2014 data) that approximately 70 percent of customers benefited from the introduction of the two tier rates.

Residential customers are likely to be divided on the issue of how to restructure the residential rate based on their own consumption levels. Clearly, those with higher-than-average consumption are unhappy with the current rate RCR rate structure and have made their voices heard through a number of channels, including the consultation phase of this proceeding. A return to a residential rate that is more aligned with cost causation, a rate with a higher fixed cost and a without a tiered consumption charge, is the most logical and defensible manner of addressing these legitimate concerns.

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

6.1.6 Optional Residential Rate Recommendation

6.1.6.1 Optional Time of Use

FBC has developed new TOU Rates for all customer classes. The derivation of the rates, including Residential, and the pricing details, is the subject of Section 8 of the Application.

While FBC does not consider the level of the rates in each of the tiers in the existing RCR to be cost-based, there are elements of the Company's cost and revenue structure that are influenced by the time at which energy is consumed. For this reason, FBC can offer a time-based conservation rate that is cost-based which in turn means that customers that adjust consumption patterns will, over the long term, provide rate mitigation to customers in general.

FBC is applying to update the TOU rates for all classes as described in Section 8 of the Application. For the residential class, since the current TOU rates are closed to new participants, FBC is also seeking Commission's approval to reopen TOU rates for all residential customers in conjunction with the availability of the new TOU rates for all classes.

6.2 COMMERCIAL SERVICE AND IRRIGATION RATES

FBC has three broad categories of commercial rates: Small Commercial, Commercial, and Large Commercial. The particular rate for which a customer is eligible will depend on the size of the customer's load, and in the case of Large Commercial, the delivery voltage.

Although not identified as such in the Electric Tariff, the Large Commercial service rates are often identified as "Industrial" in other regulatory filings.

Within each of the three broad categories there is the default rate and an optional TOU rate.

Consistent with the Company's objective within the RDA to have rates that better reflect the fixed costs identified within the COSA, FBC proposes that Commercial rates, while not changing in their basic structure, incorporate a shift in cost recovery such that a greater proportion of the class allocated costs are recovered through the Customer Charge and/or Demand Charges.

As discussed in Section 3.5, the choice of the target level for fixed cost recovery has been set such that for both the Customer Charge and Demand Charge, a consistent level of cost recovery can be reached across the customer classes, but that adjustments to individual rate schedules should not be extreme, and that some rate schedules will require no adjustment. This also results in a minimum threshold that differs for the Customer Charge and Demand Charge. FBC has proposed that the Customer Charge will increase if the current level recovers less than 55 percent of the customer costs in the COSA, and that the Demand Charge will increase if the current level recovers less than 65 percent of the demand related costs in the COSA. Customer and Demand Charges that are already at that level, or above, will not change.

These changes are discussed in detail in the following sections.

6.2.1 Small Commercial (RS 20) Rate

The Small Commercial rate is available to non-residential Customers with Demand not more than 40 kW. In the COSA, there are 13,500 RS 20 customers on RS 20, representing approximately 10 percent of both customers and energy sales.

The current RS 20 rate components and the corresponding COSA unit costs are shown in Table 6-11 below:

Table 6-11: RS 20 – Current Rate and COSA Unit Costs

Rate Schedule 20 Rate Component	Existing Tariff Rate	COSA Unit Costs	COSA Unit Percentage
Customer Charge ($/mo)	19.40	41.71	46%
Energy Rate ($/kWh)	0.10195	0.0873	

6.2.1.1 Small Commercial (RS 20) Rate Discussion

FBC is not proposing any structural changes to RS 20 Small Commercial. Given that fixed-cost recovery as represented by the Customer Charge is currently 46 percent of the COSA-derived value, FBC proposes to set the Customer Charge at 55 percent of the COSA amount, or $23.00 per monthly billing period. This represents an 18.9 percent increase to the Customer Charge and will be offset by a 1.9 percent decrease to the Energy Charge (to $0.1000 per kWh) in order for the rate to remain revenue neutral to the existing rate.

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

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

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

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

6.2.1.2 Small Commercial Rate Recommendation

The recommended rates for the Small Commercial Default Rate is shown in Table 6-13 below.

Table 6-13: RS 20 – Current and Proposed Rate

Rate Schedule 20 Rate Component	Existing Tariff Rate	Current COSA Unit Cost Percentage	Proposed Rate	COSA Unit Cost Percentage Recovery of Proposed Rate
Customer Charge ($/mo)	19.40	46%	23.00	55%
Energy Rate ($/kWh)	0.10195		0.10000	

6.2.2 Commercial (RS 21) Rate

The Commercial rate is available to non-residential Customers with Demand more than 40 kW and less than 500 kW. In the COSA, the RS 21 customer class represents approximately 1 percent of customers and 18 percent of energy sales.

As at October 31, 2017, there were 1,370 customers taking service on this rate.

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

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

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

6.2.2.1 Commercial Rate Discussion

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

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

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

6.2.2.2 Commercial Rate Recommendation

FBC is proposing a number of adjustments to the Commercial Default Rate in order to address the above issues, specifically:

- flattening of the Energy Charges from a 2-Tier declining block rate to a single energy rate that applies to all consumption;
- increasing the Customer Charge to 55 percent of the COSA-derived value; and
- increasing the Demand Charge to 65percent rate to better reflect the COSA-derived value.

The recommendation for the Commercial Default Rate is shown in Table 6-15 below.

Table 6-15: RS 21 – Current and Proposed 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%

The revenues recovered from the Commercial class are unchanged and these adjustments will not result in additional revenue to FBC (i.e. the changes are revenue neutral for the Commercial class).

The bill impacts of these proposals are shown in Table 6-16 below. There are annual bill reductions for the majority of customers, which are those customers at the lowest consumption strata, offset by small percentage increases for a smaller number of customers with higher consumption. The increase in percentages is not linear due to variations in peak demand.

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

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

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

Table 6-17: RS 21 Bill Impact by Percentage

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

6.2.2.3 Transformation Discount

The Commercial rate is designed on the basis that customers receive service at secondary voltage. However, some customers choose to own the transformation equipment required to convert their service voltage from the Primary level to the Secondary level. In these cases, the customer is actually taking service at the Primary voltage available at the location of the interconnection, and the customer is entitled to a discount from the demand charge rate in the rate schedule as transformation and secondary costs would normally be included in the rate.

There are currently thirty-one RS 21 customers that receive the transformation discount.

In looking at the appropriate discount for taking service at a higher voltage level, the COSA results were used to establish the difference in costs. The COSA is set up to account for the voltage level associated with each customer class. That allows the allocation of costs to the class for the specific facilities used by customers within the class.

To determine the difference in costs solely on the basis of a change in voltage level, the COSA was recalculated assuming a higher voltage level for the class in question. The difference was calculated independently for each class where such a discount is offered, but assumed the entire class rather than specific customers was served at the higher voltage level.[53] None of the load data or allocation factors were changed for the various classes when completing the calculation. The only difference would be that certain costs were no longer assigned to the class. The resulting difference in the unit costs for each class was then taken from the COSA to determine the appropriate discount level of a per kVA basis.

For RS 21, the 2017 COSA indicates that a transformation discount of $0.28 per kW of Billing Demand should be applied to the Demand Charge portion of the rate. The current transformation discount is $0.53 per kW of Billing Demand. FBC is proposing to include the updated amount as the transformation discount in the delivery and metering voltage discounts section of RS 21.

[53] The transformation is currently available only to RS21 and RS30 customers as they have a Demand-related billing component and a higher than standard delivery voltage may be available.

Customers on RS 21 may also be entitled to a metering discount if they are metered at the primary voltage rather than the secondary voltage in recognition of transformer losses. However, since this discount is expressed in tariff as, "a discount of 1 1/2%" applied to the rate, it does not change as a result of the 2017 COSA.

6.2.3 Large Commercial Service – Primary (RS 30) Rate

RS 30 customers are those with a demand of 500 kVA or more taken at the Company's standard primary distribution voltage. In the COSA, the RS 30 customer class has 46 customers (less than 1 percent of the total) and represents approximately 10 percent of energy sales.

FBC is not proposing any structural changes to RS 30 Large Commercial Service – Primary. The fixed charge elements, the Customer and Demand Charge, are already at or above the 55 percent and 65 percent levels respectively. Accordingly, no adjustments to the rate levels are proposed.

Table 6-18: RS 30 – Current and Proposed Rate

Rate Schedule 30 Rate Component	Existing Tariff Rate	COSA Unit Costs	COSA Unit Cost Percentage	Proposed Tariff Rate
Customer Charge ($/mo)	945.04	1,474.98	64%	945.04
Energy Rate ($/kWh)	0.05571	0.0383		0.05571
Demand Rate ($/kVA)	9.19	14.00	66%	9.19

6.2.3.1 Transformation Discount

The transformation and metering discounts described in the RS 21 section also are a feature of RS 30. In the case of RS 30, service is normally taken at the Primary voltage and may be taken at Transmission voltage if the customer chooses to own the associated transformation equipment.

The only RS 30 customer currently receiving this discount is FEI, for service to its Hedley compressor station.

The same calculations are performed for RS 30 as described for RS 21. For RS 30, the 2017 COSA indicates that a transformation discount of $5.26 per kVA of Billing Demand shall be applied to the Demand Charge portion of the rate. The current transformation discount is $2.676 per kVA of Billing Demand. The increase in the discount results from growth in costs and higher kVA per customer in the 2017 COSA, which results in a near doubling of distribution costs per kVA when compared to the 2009 COSA. FBC is proposing to include the updated amount as the transformation discount in the delivery and metering voltage discounts section of RS 30.

Similar to customers on RS 21, RS 30 customers may also be entitled to a discount if they are metered at the Transmission voltage rather than the Primary voltage in recognition of transformer losses. Since this discount is also expressed in the Electric Tariff as, "a discount of 1 1/2%" applied to the rate, it does not change as a result of the 2017 COSA.

6.2.4 Large Commercial Service – Transmission (RS 31) Rate

The Large Commercial Transmission rate is available to non-residential Customers with loads of 5,000 kVA served at 60 hertz, three phase power with a nominal potential of 60,000 volts or higher. In the COSA, there were four customers taking service on this rate representing approximately 3 percent of energy sales.

6.2.4.1 Current Large Commercial – Transmission Rate

The billing components of the Large Commercial – Transmission Rate are a monthly Customer Charge, an Energy Charge, and demand charges that are divided into a Wires Charge and a Power Supply Charge. The split in the demand charges was approved by the Commission as part of the October 2010 Decision on FBC's 2009 COSA and RDA.

The Wires Charges are assessed on the peak demand recorded during the month, and may be subject to a billing ratchet which bases the charge on the peak demand in any of the previous eleven billing periods, while the Power Supply charge is based on the peak demand only in the current billing period.

The current RS 31 rate components and the corresponding COSA unit costs are shown in Table 6-19 below:

Table 6-19: RS 31 Current Rates and COSA Unit Costs

Rate Schedule 31 Rate Component	Existing Tariff Rate	COSA Unit Costs	COSA Unit Cost Percentage
Customer Charge ($/mo)	3,116.03	5,810.78	54%
Energy Rate ($/kWh)	0.05516	0.0379	
Wires Charge Demand Rate ($/kVA)	4.93	7.34	67%
Power Supply Demand Rate ($/kVA)	2.77	5.31	52%

6.2.4.2 Large Commercial – Transmission Rate Recommendation

As with RS 30, FBC is not proposing any structural changes to RS 31 Large Commercial Service – Transmission. FBC is proposing a redistribution of revenue recovery among the fixed and variable elements of RS 31 consistent with the approach taken for other rate classes, as follows:

Table 6-20: RS 31 – Current and Proposed 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%

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

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

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

6.2.5 Optional Commercial Rates

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

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

6.2.6 Current Irrigation Rates

Service to Irrigation and Drainage customers (Irrigation) is provided pursuant to RS 60 (default Irrigation flat rate) and RS 61 (Optional TOU rate).

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 (RS 20 or RS 21 or the TOU variant) depending on eligibility, but remain as part of the Irrigation class for the purpose of cost allocation within the COSA.

In the COSA, the irrigation customer class has 1,095 customers and represents approximately 1 percent of energy sales.

The current rates for the Irrigation class are found in the table below.

Table 6-22: RS 60 – Current Rate

RS 60 Rate Component	Existing Tariff Rate	COSA Unit Costs	Current COSA Unit Cost Percentage
Customer Charge ($/mo)	20.06	40.17	50%
Energy Rate ($/kWh)	0.07259	0.07720	

6.2.6.1 Irrigation Directives

In the 2009 COSA and RDA, the Irrigation Class was found to have an R/C ratio of 88.8 percent[54] using the load data and assumptions available to FBC for the class at the time. Given this outcome, FBC recommended that the Irrigation class be included in any rebalancing of customer rates that would take place in response to the 2009 COSA. However, in the October 2010 Decision, the Commission panel made a number of determinations with respect to the treatment of the Irrigation class. These are best summarized by Directive 11 of Order G-156-10, which reads,

> FBC is directed to undertake load research to establish the load characteristics of the Irrigation class. Until FBC is better able to demonstrate the load characteristics of the Irrigation class, the Irrigation class is exempt from rate rebalancing and is subject only to base adjustments associated with FBC's revenue requirement and BC Hydro flow-through.

Therefore, the Irrigation class was exempt from the rebalancing that occurred as a result of the 2009 COSA and RDA.

In its December 17, 2010 Compliance Filing to Order G-156-10 in the 2009 COSA and RDA process, the Company suggested that the further analysis of the Irrigation rate class would proceed as follows:

1. Conduct load research, in order to properly segment, the Irrigation class by load and/or usage characteristics.
2. Draft Irrigation rates to reflect the results of the load research. This may include the creation of new rates should the data collected warrant it.
3. Consult with existing (bona fide) Irrigation customers on both the composition of the rates, and, as required by the Order, on eligibility requirements for each.

[54] November 19,2010 Compliance filing to the 2009 FortisBC Rate Design Application – COSA Re-filing Pursuant to Commission Order G-156-10.

4. Incorporate results into future COSA and rebalancing as required.

With respect to the load research, in the same filing FBC indicated that it expected to perform a load research program specific to the Irrigation class during 2011, with the prospect that data may need to be collected into 2012 in order to gather the information necessary to properly evaluate the class.

Test meters capable of recording interval data were installed at a sample of 67 services between the summers of 2012 and 2013. The data gathered from these sample services, along with the interval data now available for all irrigation customers for 2016 as a result of AMI implementation, have been used to refine the load profiles for Irrigation customers as a class.

Early on in the development of the 2017 COSA, FBC examined the Irrigation customer class in greater detail in order to determine whether the additional data and refinement of the load profile would provide similar R/C results to 2009. The 2017 COSA results indicate that the Irrigation customer class has an R/C ratio of 97.2 percent which is higher than what was found in 2009. Based on this R/C ratio, no rate rebalancing is required.

FBC has also reviewed the customers served on the Irrigation rates in an effort to determine if there are marked differences in consumption patterns between the different types of customers, as those could be identified through obvious account descriptors. For example, accounts that were clearly golf courses, municipalities or orchards, etc. could be compared for common load characteristics. The results did not indicate differences in load profile that would point to a further division of the Irrigation customers into multiple classes. Since rates are designed predominantly with respect the load profile, there is no cost basis upon which to differentiate customers as either "bona fide" or not "bona fide". In other words, based on the review, the various customer types are equally well suited to the current rate and there is no material cross-subsidization occurring between them. FBC has not identified a group of irrigation customers who are not "bona fide", or to establish criteria for what would delineate eligibility for service under RS 60 or RS 61. Since the load research did not indicate the need for new rates, consultation on those rates was not required.

6.2.6.2 Proposed Irrigation Rate

In consideration of the above discussion, FBC proposes changes change to RS 60 as shown in Table 6-23 below. These changes raise the Customer Charge in order to achieve 55 percent cost recovery and reduce in the energy charge rate.

Table 6-23: RS 60 – Proposed Rate

Rate Schedule 60 Rate Component	Existing Tariff Rate	Proposed Tariff Rate	Proposed COSA Unit Cost Percentage
Customer Charge ($/mo)	20.06	22.09	55%
Energy Rate ($/kWh)	0.07259	0.07240	

6.2.6.3 Additional Irrigation Changes

During the consultation leading up to the filing of the Application, FBC received a request from the Keremeos Irrigation District (KID) to consider a further change to the treatment of Irrigation customers as described in the following excerpt from KID's letter,[55]

> We would like to request that FBC incorporate the option to allow Irrigation Customers to utilize "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.

At the current time, Irrigation customers taking service during the irrigation season on RS 60 cannot take service on a Commercial TOU rate during the non-irrigation part of the year. A TOU option is only available to Irrigation customers taking service under the existing Irrigation TOU rate (RS 61) which is a year-round TOU rate.

The request from KID is for RS 60 customers to be able to take service under a commercial TOU rate for the non-irrigation season only.

FBC has examined the impact of this change and finds that these customers have the ability to shift their loads in the non-irrigation season, and that the change would have a minor impact on other customers, but is not proposing the change at this time. As such, the following information is provided for discussion purposes only.

In order to effect this change FBC would need to revise the Rate portion of RS 60 as follows (changes are underlined):

> *During the Non-Irrigation Season*
>
> Customers will be transferred to the applicable ~~general~~ Commercial or Commercial – Time of Use service rate. Customers electing a Time of Use option are required to provide notice to the Company by September 1st or non-Time of Use rates will be applied for the entire subsequent non-irrigation season.

FBC believes further investigation into technical and customer information systems issues is required before recommending this change, and these issues may require significant time and expense to overcome. It is also possible that implementation issues may only have solutions that are cost prohibitive. FBC proposes to further investigate the implementation of an off-season TOU Irrigation and Drainage rate and to report back to the Commission.

[55] The KID letter is included in Appendix K to the Application.

6.3 WHOLESALE RATES

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. In all cases, the Wholesale customers purchase electricity in order to resell to end-use customers.

In the COSA, there are seven wholesale customers that represent approximately 17 percent of energy sales.

6.3.1 Current Wholesale Rates

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.

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

Table 6-24: Wholesale Rate Details

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

6.3.2 Optional Wholesale Rates

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

- **RS 42, Wholesale Service – Primary, Time of Use**
- **RS 43, Wholesale Service – Transmission, Time of Use**

The TOU rate schedules are available to the same utilities as the respective underlying rate schedule. FBC does not have any wholesale customers taking service on a TOU rate.

6.3.3 Wholesale Rates Discussion and Proposals

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

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

6.3.4 Transmission Discount

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

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

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

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

Table 6-25: RS 40 Transmission Discount

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

7. TRANSMISSION SERVICES

FBC has offered transmission services since Commission approval of the rates proposed by the Company in its Transmission Access Application filed in March of 1998.[56]

Customers that are eligible for the use of these services are those that meet the criteria provided in Section 1.11 of the Company's Tariff Supplement No. 7.[57]

The transmission services rates and associated ancillary service facilitate the non-discriminatory use of the FBC transmission system by third parties. FBC provides an overview of the current rates (Section 7.1) and information on the two main requests for which approval is being sought from the Commission. These are:

- Transmission Rate Request 1 - A clarification to the rate language in RS 101 and RS 102 as described in Section 7.2; and
- Transmission Rate Request 2 - Updates to the pricing for the existing Point-to-Point (PTP) transmission rates and related ancillary services (including the closure of RS 102 which is no longer required) (Section 7.3).

7.1 CURRENT TRANSMISSION SERVICES RATES

The rates and services included in the Transmission Service portion of the Company's Electric Tariff are shown in Table 7-1 below. Each of these services is described in greater detail in a following sections.

Table 7-1: Transmission Service Rates

Wholesale Transmission Access Services	Rate Schedule
Network Integration Transmission Service[58]	100
Long-Term and Short-Term Firm Point-To Point Transmission Service	101
Non-Firm Point-to-Point Transmission Service	102
Ancillary Services	**Rate Schedule**
Scheduling, System Control and Dispatch Service	103
Reactive Supply and Voltage Control from Generation Sources Services	104
Regulation and Frequency Response Service	105
Energy Imbalance Service	106
Operating Reserve (OR) - Spinning Reserve Service	107
Operating Reserve (OR) - Supplemental Reserve Service	108
Transmission Losses	109

[56] Commission Order G-27-99.
[57] https://www.fortisbc.com/Electricity/CustomerService/TransmissionServices/Documents/TariffSupplement7March10-99.pdf
[58] The charges for Network Integration Transmission Service are calculated based on the applicable Load Ratio Share of one twelfth (1/12th) of the Network Transmission Revenue requirement per month. Since these charges are formulaic in nature, they do not change as a result of the 2017 RDA.

The current pricing included in RS 101 is summarized in Table 7-2 below.

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

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

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

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

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

It should be noted here, and considered in the discussion that follows in Section 7.2.2, that with the exception of the minimum price, the rates in RS 101 and RS 102 are identical.

In addition to the rates sets out in the two tables above, each of the rates also contains a Minimum Price ($0.002/kW/hour for RS 101 and $0.001/kW/hour for RS 102) which sets a floor price in the case where discounting (as described below) occurs, which is intended to cover administrative costs.

The Special Provisions for each rate contain language allowing discounts to be provided under certain conditions. Generally, discounting of the posted maximum rates may occur when all of the following conditions apply:

- the increased usage will not add to system costs over the term requested;
- the customer can demonstrate that an alternative transmission path with another Transmission Provider is available at a lower cost; and
- the lack of a discount would result in curtailment of transmission use for economic reasons.

For example, if a new IPP could connect to BC Hydro or FBC, and sell to two different third parties along two different underutilized paths, located in the distinct service areas, then FBC may offer a discount.

The discount would be determined with the intent of maximizing the revenue generated. Considered in the calculation of a discount would be factors such as the likely price on the alternate path, and the load carrying capability of both paths over time.

Current pricing for the ancillary services is contained in Table 7-4 below. These services are discussed in greater detail in Section 7.4 of the Application.

Table 7-4: Current Ancillary Services Pricing

	Schedule	Unit	Large Commercial Service Transmission	Wholesale - Primary	Wholesale - Transmission
Scheduling, System Control and Dispatch Service	103	Per kWh	$0.00126	$0.00132	$0.00126
Reactive Supply and Voltage Control from Generation Sources Services	104	Per kWh	$0.00141	$0.00132	$0.00132
Regulation and Frequency Response Service	105	Per MW per hour of generating capacity; minimum of 2% of the Customer's load	$13.62		
Energy Imbalance Service	106	See Section 7.4.4	$0.05043	$0.0480	$0.04798
Operating Reserve (OR) - Spinning Reserve Service	107	Minimum level of service required per Tariff	$13.62		
Operating Reserve (OR) - Supplemental Reserve Service	108	Minimum level of service required per Tariff	$13.62		
Transmission Losses	109		6.08%	11.53%	6.08%

7.2 TRANSMISSION RATE REQUEST 1 – CLARIFICATION TO THE EXISTING POINT-TO-POINT (PTP) RATE LANGUAGE

This section discusses the proposed updates to both RS 101 and RS 102. It should be noted, however that as part of the Application, FBC is proposing to remove RS 102 from use and from the Electric Tariff.[59] The detailed discussion of RS 102 updates that is included here is provided in the event that its removal is not approved by the Commission and the changes would then be required. In the event that the removal of RS 102 is approved, all of the updates to RS 101 described below are still required.

Updates to the language contained in RS 101 (Long-term and Short-Term Firm Point-to-Point Transmission Service) and RS 102 (Non-Firm Point-to-Point Transmission Service) are required because the rate schedules, if used to facilitate services other than those anticipated at the time the schedules were originally approved, can be interpreted incorrectly with the potential to lead to FBC being deprived of appropriate revenue that could be used to lower rates for load customers.

This portion of the Application is distinct from any changes to the rates or charges contained in the affected rate schedules, or in how they will be applied to new customers or the renewal of transmission related agreements for existing customers.

Prior to filing, FBC discussed these changes with BC Hydro and has confirmed that BC Hydro agrees that the Application is consistent with the anti-pancaking principles[60] set out in Order G-12-99, which is discussed below. While FBC has chosen to address this issue directly through a tariff amendment, BC Hydro has provided a similar clarification for its customers through its business practice.[61]

Prior to discussing the proposed changes, FBC provides some regulatory history as background to this aspect of the Application.

7.2.1 Regulatory History

On March 9, 1998, FBC (West Kootenay Power at the time) filed a Transmission Access Application seeking approval of wholesale transmission access and retail transmission access for its Industrial and Municipal customers. BC Hydro already had wheeling rates in place, which were required to achieve a Power Marketing Agreement (PMA) in compliance with Federal Energy Regulatory Commission (FERC) requirements. As part of the FBC process, attendees at a pre-hearing conference stated a need for the harmonization of BC Hydro and FBC

59 See Section 11.2.2 of this Application.

60 As returned to below, "pancaking" involves the stacking of transmission tariffs which would result in customers paying the tariffs of both utilities when power was moved between the two service territories.

61 BC Hydro's approach is explicitly described in the "Note to Table 2" on page 6 of *Open Access Transmission Tariff - Business Practice, Posting of Transmission Service Offerings* available at the following link: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/suppliers/transmission-scheduling/business_practices/2016%20October%20-%20Posting%20of%20Transmission%20Service.pdf

transmission rates. This would prevent the stacking of transmission tariffs, which would result in customers paying the tariffs of both utilities when power was moved between the two service territories. Such stacking or "rate pancaking", at the time, would have made wholesale transmission access uneconomic.

At the Commission's behest, on October 5, 1998 BC Hydro and FBC jointly applied for amendments to their tariffs and power purchase arrangements which were intended 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.*" (G-12-99 Recital C).

In the joint application, FBC and BC Hydro agreed that the harmonization arrangements should not influence FBC's decisions as to whether to source energy under its existing power purchase agreement with BC Hydro or from alternate sources. Similarly, BC Hydro's purchases from FBC under FBC's wholesale rate schedule were not to be influenced. To reflect this principle the parties agreed to amend various agreements. The joint application further stated that:

> The proposed changes to the power purchase agreements set out in Appendix C should ensure neutrality in FBC's and BC Hydro's evaluations of their supply alternatives in most foreseeable circumstances. However, if actual experience after harmonization is introduced leads either party to believe that FBC's or BC Hydro's supply decisions are being affected by the harmonization arrangements, the parties will work together to determine what further steps can be taken to ensure ongoing neutrality.

This application was subsequently approved in February of 1999 (via Order G-12-99) with the most relevant tariff modifications being the insertion in FBC's transmission tariff of the phrase *"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."* A reciprocal phrase was inserted into the analogous tariff schedule of BC Hydro. On April 1, 1999 the Power Purchase Agreement between BC Hydro and FBC was also amended to expressly state that that if FBC made use of BC Hydro's system to serve FBC Native Load Customers then BC Hydro's transmission tariff rate under its OATT Schedule 01 (then Schedule 3001) would apply.

It is clear from that 1998 harmonization application that a situation whereby BC Hydro would be purchasing power to serve its native load from within the FBC service territory was not addressed. Historically FBC had been both capacity and energy deficient and sourced the deficiency from BC Hydro under the PPA and from third parties. The harmonization clauses were intended to directly address the situation where wholesale or large retail load customers required the use of both transmission systems when sourcing power from a third party to serve load.

FBC has included, as part of the current Application, Appendix I which contains documents relevant to this discussion.

These documents are:

- **Appendix I-1** 1998 Joint BC Hydro WKP Harmonization Application
- **Appendix I-2** Commission Letter Dated October 23, 1998
- **Appendix I-3** Commission Order G-12-99

7.2.2 Rationale for the clarification to the Existing Point-to-Point (PTP) Rate Language

No entity has ever used the Transmission Services for the provision of Wholesale or Retail Access as was originally intended. However, the export of self-generation (SG) and Independent Power Producer (IPP) output has been facilitated by RS 101 and select ancillary services.

The continued use of the Point-to-Point transmission service to export SG and IPP output, in particular when the receiving party is BC Hydro, requires an amendment to the rate schedules as described in the following section

At present, the wording in the Wholesale Transmission Service (RS 101 and RS 102) includes the following phrase prescribing that the rate charged for these services:

> …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.

This language can be misinterpreted to enable Eligible Customers[62] located within the FBC service area that have generation capability, to deliver power to BC Hydro, where BC Hydro is purchasing the power to serve its network load, without FBC receiving any wheeling revenue in consideration of the use of the FBC system that is required in order to facilitate the delivery. The tariff language that has been misinterpreted to enable the avoidance of wheeling payments, was put in place <u>specifically</u> to harmonize the transmission rates of FBC and BC Hydro to avoid the pancaking of rates for customers that sought to serve their loads from a third party and where the transmission systems of <u>both utilities</u> would be required to deliver the power to the customer site (Rate Harmonization).

The Commission described the purpose of Rate Harmonization in the Reasons for Decision accompanying Order G-12-99[63],

> The objective of harmonization is to eliminate rate stacking or "pancaking" - that is, the payment by customers of two transmission wheeling tariffs on transactions where power is moved between utility service areas.

[62] Eligible Customers as defined in Section 1.2 of Commission Decision G-28-99 includes, Wholesale Customers, Large Commercial Customers served at Transmission Voltage, Power Marketers, and IPP.

[63] Commission Order G-12-99 and the accompanying Reasons for Decision are attached as Appendix I-3.

More specifically, the Commission included the following description in its October 23, 1998 letter to interveners in the British Columbia Hydro and Power Authority and West Kootenay Power Ltd. - Rate Harmonization process:

> ..The purpose and effect of the amendments is to relieve wholesale transmission customers from the requirement to pay both B.C. Hydro's and FBC's wholesale transmission rate by charging only the wholesale transmission rate of the utility within whose service area the customer is located.[64]

In the situation where an Eligible Customer seeks to deliver power generated within the FBC service area to BC Hydro, there is no opportunity for a customer to make use of "two transmission wheeling tariffs". The change that FBC is seeking would maintain the original intent of the anti-pancaking provisions but would allow for the collection of appropriate revenue from IPPs and self-generating customers selling power to BC Hydro, which would provide rate mitigation for all other FBC customers.

As a result of the misinterpretation of the anti-pancaking language, FBC currently has two self-generation customers that are exporting power to BC Hydro and paying no transmission related charges except those for select ancillary services.

FBC requests changes to the text of RS 101 and RS 102 as detailed in the following sections, with the additional language underlined.

7.2.3 Rate Schedule 101

7.2.3.1 Annual Rate for Long-Term Firm Service

The proposed addition to the RS 101 tariff schedule is below, with the added language underlined.

Under the heading in the RS 101 rate schedule, <u>ANNUAL RATE FOR LONG-TERM FIRM SERVICE:</u>

> 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>

[64] The October 23, 1998 letter to interveners is attached as Appendix I-2.

7.2.3.2 Rates for Short-Term Firm Service

The same language is required in the short-term section of the tariff schedule.

Under the heading in the RS 101 rate schedule, RATES FOR SHORT-TERM FIRM SERVICE:

> 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 the POD is a point of interconnection between the Transmission System and the transmission system of the B.C. Hydro and Power Authority, 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.

7.2.4 Rate Schedule 102

RS 102 contains a similar provision and therefore a similar clarification is proposed, (in the event that RS 102 is not closed as requested in the Application)

7.2.4.1 Rates for Short-Term Non-Firm Service

Under the heading in the RS 102 rate schedule RATES FOR SHORT-TERM NON-FIRM SERVICE: MAXIMUM PRICE:

> 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, 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.

7.3 TRANSMISSION RATE REQUEST 2 – UPDATES TO THE PRICING OF TRANSMISSION AND ANCILLARY SERVICES

FBC is seeking two primary revisions to the Transmission Service Rates. The first revision is a simplification and update to the pricing attached to the service. The updated prices are derived from the 2017 COSA utilizing the Transmission Revenue requirement. The second revision is the removal of RS 102 from FBC Electric Tariff. Since the rates are the same as with RS 101, and given the fact that FBC lacks any significant use of its transmission system that would normally underlie the provision of a non-firm wheeling service and none is anticipated, FBC has concluded that RS 102 is not needed.

The Transmission Services rates have not been adjusted on any basis other than as the result of a Revenue requirement related increase since they were first put in place. As part of the current Application, a review of the assumptions and cost-based foundation of the rates was conducted.

7.3.1 Proposed Transmission Service Rates

The current RS 101 and RS 102 rates include a Customer Charge and pricing that varies both by customer type and connection voltage, and by Reservation time period (as shown in Tables 7-2 and 7-3 above).

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

Table 7-5: Updated PTP Transmission Rates

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

* Per KW of Reserved Capacity Billing Demand

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

7.4 ANCILLARY SERVICES

FERC defines ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."[65]

Ancillary Services are available as required to maintain system reliability within the service area.

The Ancillary Services that the Transmission Customer is required to obtain from FBC are:

- Scheduling, System Control and Dispatch Service - Rate Schedule 103; and

65 https://www.ferc.gov/market-oversight/guide/glossary.asp

- Reactive Supply and Voltage Control - Rate Schedule 104.

In addition, the Transmission Customer may elect to obtain the following Ancillary Services from FBC, or with FBC acting as its agent, obtain the services from a third party, or by self-supply:

- Regulation and Frequency Response Service - Rate Schedule 105;
- Energy Imbalance Service - Rate Schedule 106;
- Operating Reserve – Spinning - Rate Schedule 107;
- Operating Reserve – Supplemental - Rate Schedule 108;
- Loss Compensation - Rate Schedule 109

As part of the Application, FBC has reviewed the Ancillary services and updated the rate schedules as shown in Appendix G, the Black-lined Tariff. A brief description of each of the above-listed Ancillary Services is contained in the following sections.

7.4.1 Rate Schedule 103 – Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service is required to schedule the movement of power through, out of, within, or into FBC's service territory.

The Transmission Customer must purchase this service if taking supply under RS 100, RS 101 or RS 102.

FBC has reviewed the costs associated with this service and has determined that a single rate for all classes of customers is most appropriate as the cost of providing the service is not dependent on the customer class.

The existing rate for RS 103 is $0.00126 per kWh. The proposed rate is $0.00031 per kW of Reserved Capacity per hour. The units are changed from energy to capacity per hour to more closely follow industry practise including the BC Hydro tariff RS 03.

The rates are derived directly from the 2017 COSA utilizing the costs associated with the System Control Centre that provides the service, divided by the sum of the non-coincident system peaks. The COSA values, derivation, and COSA Schedule reference are shown in Table 7-6 below.

Table 7-6: Derivation of RS 103

Description	Value	Reference
Expenses for System Control (Acct 556)	$2,298,000	COSA Schedule 3.1
Non-Coincident Peak (Sum of 12 months)	13,768,020 kVA	COSA Schedule 2.1
Resulting Rate103 per kW-month	$0.1669 / kVA	Row 1 divided by Row 2

The updated rates reflected in Appendix G and H are as follows.

- Monthly rate: the maximum charge shall be $0.1669/kW of Reserved Capacity per month.
- Weekly rate: the maximum charge shall be $0.0385/kW of Reserved Capacity per week.
- Daily rate: the maximum charge shall be $0.0055/kW of Reserved Capacity per day.
- Hourly rate: the maximum charge shall be $0.00023/kW of Reserved Capacity per hour.

The rates for the Weekly, Daily, and Hourly service are derived directly from the monthly rate by first multiplying the monthly rate by 12 to get an annual value and then divided by 52, 365, and 8,760 respectively.

A description of the methodology for discounting the services provided under RS 103 is contained in Section 3 of Electric Tariff Supplement No. 7 and remains unchanged.

7.4.2 Rate Schedule 104 – Reactive Supply and Voltage Control

Reactive Supply and Voltage Control is required in order to maintain Transmission Voltages on transmission facilities within acceptable limits.

FBC has reviewed the costs associated with this service and has determined that a single rate for all classes of customers is most appropriate as the cost of providing the service is not dependent on the customer class.

In order to maintain Transmission Voltages on transmission facilities within acceptable limits, generation facilities and non-generation resources under the control of FBC are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or other Sources that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain Transmission Voltages within limits that are generally accepted in the region.

The Transmission Customer must purchase this service if taking supply under RS 100, RS 101 or RS 102.

The existing rate for RS 104 is $0.00141 per kWh. The proposed rate is $0.825 per MW of Reserved Capacity per hour. The units are changed from energy to capacity per hour to more closely follow industry practise including the BC Hydro tariff RS 04.

The charge for Reactive Supply and Voltage Control is based on the BC Hydro rate. FBC believes it is appropriate to use a provincially calculated number since there is no calculated entitlement MVAR availability under the Canal Plant Agreement with BC Hydro.

A description of the methodology for discounting the services provided under RS 104 is contained in Section 3 of Electric Tariff Supplement No. 7 and remains unchanged.

7.4.3 Rate Schedule 105 – Regulation and Frequency Response Service

Regulation and Frequency Response (RFR) is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz).

RFR Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The Transmission Customer must either purchase this service from the Company or make alternative comparable arrangements to satisfy its RFR Service obligation. The amount of and charges for RFR Service are set forth below.

The proposed rate is based on updated costs from the 2017 COSA, as shown in Table 7-7 below.

Table 7-7: Derivation of RS 105

Description	Value	Reference
COSA Costs for Demand-Related Production	$46,785,544	COSA Schedule 2.1
Sum of Monthly System Coincident Peak Demand (kW)	6,883,787	COSA Schedule 8.5
Resulting Rate on per kW-month Basis	$6.80	Row 1 divided by Row 2
Average Hours per Month	730	
Resulting rate on per kW per hour Basis	$0.00931	Row 3 divided by Row 4

The resulting rate as expressed in the tariff is $9.31 per MW per hour of generating capacity requested for RFR. The existing rate is $13.62 per MW per hour of generating capacity requested for RFR.

The required amount of RFR Service is a minimum of 2 percent of the Customer's load located in the Company's service territory.

A description of the methodology for discounting the services provided under RS 105 is contained in Section 3 of Electric Tariff Supplement No. 7 and remains unchanged.

7.4.4 Rate Schedule 106 – Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy over a single hour.

Energy imbalances are calculated hourly based on deviations from scheduled generation and load. Positive imbalances occur when actual generation is greater than scheduled generation or when actual load is less than scheduled load, and results in a delivery of energy from the customer to the Company. Negative imbalances occur when actual generation is less than scheduled generation or when actual load is greater than scheduled load, and results in a delivery of energy from the Company to the customer. The Transmission Customer must either purchase Energy Imbalance Service from the Company or make alternative comparable arrangements to ensure its transmission schedules are balanced in each hour.

While the proposed pricing of other Ancillary Services included in the Application has remained generally consistent with past practice, FBC is proposing to update RS 106 to reflect current practice and consideration of the Company's operations.

Currently, Energy Imbalance Service is offered on the basis and at the charges described in the current tariff as reproduced below.

> Customers are allowed to maintain a ±1.5% balance between generation (minus losses) and load within the hour. The ±1.5% hourly balance limit is based on the capacity reserved. Positive hourly imbalances within the ±1.5% band not eliminated within 30 days, will attract a credit that is equal to the Company's minimum monthly cost of purchasing energy. If the Company does not purchase energy during the month, the previous minimum price will be used. Positive hourly imbalances outside the ±1.5% band will be forfeit.
>
> For negative energy imbalances (when generation minus losses is less than load) that fall within the ±1.5% band and are not eliminated within 30 days, the energy imbalance charge will be:

Wholesale Service-Transmission:	$0.05043 per kW.h
Wholesale Service-Primary:	$0.04800 per kW.h
Large Commercial Service-Transmission:	$0.04798 per kW.h

> For any negative energy imbalances (when generation minus losses is less than load) that fall outside the ±1.5% band the energy imbalance charge will be the actual cost the Company incurs in supplying that imbalance, plus 10%.

FBC proposes that charges or credits from imbalance will be based on the Mid-Columbia hourly market prices with the exception that for negative imbalances greater than 4 MW, imbalance charges would be similar to what FBC would pay to BC Hydro under the Imbalance Agreement between FBC and BC Hydro as approved by the Commission in Order G-60-14. In addition, credits for positive system imbalance will be capped at the BC Hydro PPA rate to ensure a reasonable cap on the price that FBC will pay for imbalance power. System losses will also be applied to negative imbalance and a 10 percent administrative premium will be applied to both positive and negative imbalance.

The revised structure and charges for Energy Imbalance Service are set forth below.

1. A positive imbalance will be credited as the lower of:

   (a) the Tranche 1 Energy Price set out in BC Hydro Rate Schedule 3808 as of January 1 in the calendar year in which the available surplus power is delivered; and

   (b) The hourly Powerdex Mid-Columbia (Mid-C) index price for the hour in which the positive Energy Imbalance Service is taken by the Customer. In hours in which the Mid-C price is negative, the negative value will be used resulting in a charge to the transmission customer for those hours.

   plus

   (c) an administrative premium of 10 percent will be subtracted from the credited amount or added to the charged amount if the index price was negative.

2. A Negative Energy Imbalance Service will be charged as follows:

   a) For hourly negative Energy Imbalance Service less than or equal to 4 MW, the charge will be:

      (i) The amount of negative Energy Imbalance Service x (1 x loss compensation % as per RS 109) multiplied by

      (ii) The hourly Powerdex Mid-Columbia (Mid-C) per kWh price for the hour in which the negative Energy Imbalance Service is taken by the Customer. In hours in which the Mid-C price is negative, a zero value will be used; plus

      (iii) The Bonneville Power authority's (BPA) wheeling rate from B.C.-U.S. Border to Mid-C. per kWh; plus

      (iv) An administrative premium of 10 percent.

   b) For hourly negative Energy Imbalance Service greater than 4 MW, the charge will be:

      (i) The amount of negative Energy Imbalance Service x (1 x loss compensation % as per RS 109) multiplied by

      (ii) The greater of

         a. $50/MWh, or

         b. 150 percent of the hourly Powerdex Mid-Columbia (Mid-C) per kWh price for the hour in which the negative Energy Imbalance

Service is taken by the Customer. In hours in which the Mid-C price is negative, a zero value will be used; plus

(iii) The BPA wheeling rate from B.C.-U.S. Border to Mid-C per kWh; plus

(iv) An administrative premium of 10 percent.

BPA's wheeling rate is available on the BPA website.

A description of the methodology for discounting the services provided under RS 106 is contained in Section 3 of Electric Tariff Supplement No. 7 and remains unchanged.

7.4.5 Rate Schedule 107 – Operating Reserve - Spinning

Operating Reserve (OR) – Spinning Service is needed to serve load immediately in the event of a system contingency and may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Company must offer this service when the transmission service is used to serve load within its service area. The Transmission Customer must either purchase this service from the Company or make alternative comparable arrangements to satisfy its OR – Spinning Service obligation. The amount of and charges for OR – Spinning Service are set forth below.

The existing rate is $13.62 per MW per hour of generating capacity requested for OR - Spinning. Currently, the required amount of OR – Spinning for a Customer depends upon the type of generation serving the load. When the load is served by hydro generation, the required amount of OR – Spinning is a minimum of 2.5 percent of the Customer's load. When the load is served by thermal generation, the required amount of OR – Spinning is a minimum of 3.5 percent of the Customer's load.

The required percentages have been updated to conform to the requirements of the NorthWest Power Pool Reserve Sharing group[66]. As is the case in the current tariff, the proposed rate is the same as that proposed for RS 105, Regulation and Frequency Response, which is $9.31 per MW per hour and is derived using the same data

The minimum OR – Spinning reserve requirement, equals the sum of:

1. 1.5 per cent of hourly integrated load; plus
2. 1.5 per cent of hourly integrated generation.

A description of the methodology for discounting the services provided under RS 107 is contained in Section 3 of Electric Tariff Supplement No. 7.

[66] http://www.nwpp.org/documents/RSGC/NWPP-RSG-Documentation-Effective-December-15-2017-for-implementation-January-1-2018.pdf, page 48

7.4.6 Rate Schedule 108 – Operating Reserve - Supplemental

OR – Supplemental Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time.

The required percentages have been updated to conform to the requirements of the Northwest Power Pool Reserve Sharing group. The requirements have changed since FBC put its current Transmission Services in place and should be reflected in the Tariff.

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Company must offer this service when the transmission service is used to serve load within its Service Area. The Transmission Customer must either purchase this service from the Company or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below.

The existing rate is $13.62 per MW per hour of generating capacity requested for OR - Supplemental. Currently, the required amount of OR – Supplemental for a Customer depends upon the type of generation serving the load. When the load is served by hydro generation, the required amount of OR – Supplemental is a minimum of 2.5 percent of the Customer's load. When the load is served by thermal generation, the required amount of OR – Supplemental is a minimum of 3.5 percent of the Customer's load.

The required percentages have been updated to conform to the requirements of the NorthWest Power Pool Reserve Sharing group. As with the case in the current tariff, the proposed rate is the same as that proposed for RS 105, Regulation and Frequency Response, which is $9.31 per MW per hour.

The minimum supplemental reserve requirement, equals the sum of:

1. 1.5 per cent of hourly integrated load; plus
2. 1.5 per cent of hourly integrated generation.

A description of the methodology for discounting the services provided under RS 108 is contained in Section 3 of Electric Tariff Supplement No. 7.

7.4.7 Rate Schedule 109 – Loss Compensation

Power transmitted over the transmission system incurs technical losses. FBC has reviewed and updated the loss percentages for connection voltage. These loss percentages are those used in the 2017 COSA as provided by FBC Engineering Services. In addition, FBC is proposing to add an option for customers to settle losses financially based on the Mid-Columbia market price rather than being required to physically deliver power to FBC as compensation for losses.

Loss compensation is required for all transactions under RS 100, RS 101 and RS 102, which under the only option current available to customers, will be assessed power losses as follows:

- Transmission Connected Service – 2.86 percent (currently 6.08 percent)
- Distribution Connected Service – 4.26 percent (currently 11.53 percent)

These losses may be scheduled to the Company as is the current practice under the existing Loss Compensation service. If this option is selected, there are no financial charges.

If the customer chooses the added option to settle losses financially based on the Mid-Columbia market price rather than being required to physically deliver power to FBC as compensation for losses pricing would be as follows:

RATE:

(i) The hourly Powerdex Mid-Columbia (Mid-C) per kWh price for the hour in which the schedule occurred. In hours in which the Mid-C price is negative, a zero value will be used; plus

(ii) The Bonneville Power authority's (BPA) wheeling rate from B.C.-U.S. Border to Mid-C per kWh; plus

(iii) An administrative premium of 10 percent.

If the transmission customer elects to purchase loss compensation service from the Company, service must be continued for a minimum period of one year. Following the one year period, the customer can cancel the election with a minimum 7 days' notice. Following a cancelled election, the customer cannot elect to take loss compensation service for a minimum of one year following the cancelled election.

This added option increases customer choice and is expected to be more administratively efficient for some customers to implement. In addition, FBC has the potential to reduce overall costs to the extent that FBC can obtain replacement power at a lower cost as a result of overall system optimisation.

7.4.8 Summary Tables

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

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

Table 7-9: Ancillary Services Rates: Current and Proposed

<table>
<tr><th></th><th></th><th></th><th>Large Commercial Service Transmission</th><th>Wholesale - Primary</th><th>Wholesale - Transmission</th><th>Primary</th><th>Transmission</th></tr>
<tr><td></td><td></td><td></td><td colspan="3">Current Rates</td><td colspan="2">Proposed Rates</td></tr>
<tr><td rowspan="4">Scheduling, System Control and Dispatch Service</td><td rowspan="4">103</td><td rowspan="4">Per kWh</td><td rowspan="4">$0.00126</td><td rowspan="4">$0.00132</td><td rowspan="4">$0.00126</td><td colspan="2">Monthly: $0.1669/kW</td></tr>
<tr><td colspan="2">Weekly: $0.0385/kW</td></tr>
<tr><td colspan="2">Daily: $0.0055/kW</td></tr>
<tr><td colspan="2">Monthly: $0.00023/kW</td></tr>
<tr><td>Reactive Supply and Voltage Control from Generation Sources Services</td><td>104</td><td>Per kWh</td><td>$0.00141</td><td>$0.00132</td><td>$0.00132</td><td colspan="2">$0.825 per MW of Reserved Capacity per hour.</td></tr>
<tr><td>Regulation and Frequency Response Service</td><td>105</td><td>Per MW per hour of generating capacity; minimum of 2% of the Customer's load</td><td colspan="3">$13.62</td><td colspan="2">$9.31</td></tr>
<tr><td>Energy Imbalance Service</td><td>106</td><td></td><td>$0.05043</td><td>$0.0480</td><td>$0.04798</td><td colspan="2">See Tariff Pages</td></tr>
<tr><td>Operating Reserve (OR) - Spinning Reserve Service</td><td>107</td><td>Minimum level of service required per Tariff</td><td colspan="3">$13.62</td><td colspan="2">$9.31</td></tr>
</table>

			Large Commercial Service Transmission	Wholesale - Primary	Wholesale - Transmission	Primary	Transmission
			Current Rates			Proposed Rates	
Operating Reserve (OR) - Supplemental Reserve Service	108	Minimum level of service required per Tariff	$13.62			$9.31	
Transmission Losses	109		6.08%	11.53%	6.08%	4.26%	2.86%

8. OPTIONAL TIME OF USE RATES

TOU rates are generally intended to incent customers to shift the time of consumption in a manner that allows a utility to reduce costs or generate incremental revenue such that a rate benefit will accrue to all customers.

FBC currently offers time-differentiated, or time of use, rates for all of its retail rate classes, although the rate for residential customers has been closed to new participants since 2012. The closure of this rate coincided with the implementation of the RCR as the default rate for residential customers.

As part of the 2017 COSA and RDA process, FBC has completed the first comprehensive review of these rates in 20 years. FBC has updated the assumptions and cost allocations associated with the rates and is proposing to reconfigure and reprice the TOU rates for all classes, and to reintroduce a TOU rate for the residential class as an optional rate for eligible customers.

The development of the updated TOU rates requires analysis of data apart from the typical cost allocations by customer classes, since the information and data contained in a typical COSA is not differentiated on the basis of time. The additional analysis on which FBC's present proposals built was enabled by the Company's Advanced Metering Infrastructure (AMI), which provides accurate hourly consumption data for FBC's customers and allows for the derivation of the appropriate TOU time periods and the optional billing option itself. This information is required so that TOU rates will, to the extent possible, be cost-based, and not simply designed as a behaviour modification tool. Unless the changes in behaviour caused by the rate result in the desired financial benefit, the rate will not have achieved its objective.

8.1 CURRENT TOU RATES

The current TOU rates offered by FBC are:

- RS 2A - Residential TOU rate (as noted above, closed to new customers since 2012);
- RS 22A - Commercial Service - Secondary - Time of Use;
- RS 23A - Commercial Service - Primary - Time of Use;
- RS 32 - Large Commercial Service - Primary - Time of Use;
- RS 33 - Large Commercial Service - Transmission - Time of Use;
- RS 42 - Wholesale Service - Primary - Time of Use; and
- RS 43 - Wholesale Service - Transmission - Time of Use.

In 2016 there were approximately 175 customers taking service under RS 2A, 20 customers on RS 22A and one customer on RS 32. There are no customers on the remaining TOU rate schedules.

The current TOU rates have pricing time periods as shown in Tables 8-1 and 8-2 below. Customers served at secondary voltage (including residential customers) have two pricing seasons. Customers served at primary voltage and above, and Irrigation customers have three pricing seasons.

Table 8-1: Current Secondary TOU Time Periods

	Summer (July, August)	Other Months
On-Peak Hours	9 am to 11 am Monday - Friday 3 pm to 11 pm Monday - Friday	8 am to 1 pm Monday - Friday 5 pm to 10 pm Monday - Friday
Off-Peak Hours	11 pm to 9 am Monday - Friday 11 am to 3 pm Monday - Friday All hours on Saturday and Sunday	10 pm to 8 am Monday - Friday 1 pm to 5 pm Monday - Friday All hours on Saturday and Sunday

Table 8-2: Current Primary and Transmission TOU Time Periods

	Winter (November – February)	Summer (July, August)	Shoulder (Other Months)
On-Peak	7 am to 12 pm business days 4 pm to 10 pm business days	10 am to 9 pm business days	6 am to 10 pm Monday - Saturday
Off-Peak	10 pm to 7 am business days 12 pm to 4 pm business days All hours on weekends and Statutory Holidays	9 pm to 10 am business days All hours on weekends and Statutory Holidays	10 pm to 6 am Monday – Saturday and all day Sunday

The current on-peak and off-peak pricing that applies to each customer class is contained in Table 8-3 below.

Table 8-3: 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

8.2 TOU RATES EVALUATION AND DESIGN

The current rates and time periods for each applicable energy charge were first set with the Company's 1997 Rate Design Application. The 1997 TOU rates resulted from a thorough analysis of the 1997 COSA and load profile that existed at the time. These rates have escalated with revenue related increases since that time, but the underlying assumptions have not been updated in the intervening period.

The following sections describe the steps required to evaluate whether the current TOU rates reflect the current load profile of FBC and associated cost information, and how any revisions to the current TOU rates should be approached in the event that updates are required.

The first step in this process was to identify and examine the appropriate TOU periods on which rates should be based and the second step was, for pricing purposes, to look at the cost differences by the time periods identified in the first step.

As described above, because the COSA does not provide the data necessary to determine how best to structure the various TOU periods, information gathered outside of the COSA was used to inform the evaluation and development of proposed TOU rates.

8.2.1 Time of Use Rate Periods

The goal in developing the TOU periods is to capture the periods that consistently have higher usage levels while at the same time setting periods that are easy to understand for customers and will not result in shifting the peak period for the utility. This is with a view to achieving the overall objective of TOU rates. As noted above, that objective is to incent customers to shift the time of consumption in a manner that would allow FBC to reduce costs or generate incremental revenue such that a rate benefit will accrue to all customers.

Appropriate TOU periods were developed by looking at the total system loads by hour for the past 5 years and to group periods with similar load levels into TOU periods. The 5-year time period was chosen in order smooth out variations in load that may be due to anomalies such as atypical weather patterns. The peak months of December/January and July/August periods were looked at in detail because these have the most potential for cost/revenue impacts.

The current TOU rates contain only an on-peak and off-peak period. However, the analysis revealed that it would better reflect system loads to incorporate an on-peak, mid-peak and off-peak period. In developing the structure, EES Consulting confirmed that this is consistent with typical TOU rates of utilities in other jurisdictions, where TOU period have changed from two to three TOU periods within certain months. While the winter and summer months both have relatively higher usage and higher costs in peak hours, loads and costs are lower in the shoulder months. The same is true within days where loads and costs are highest in the morning and early evening.

The analysis also revealed that there is no clear delineation where loads change from one level to another, as changes throughout the day and across months are gradual. There are also some days within a given month where loads are higher because of weather conditions. Loads in each hour were compared to the average load for the day. If the load in these hours was 90 percent or more of the daily peak then the hours were generally considered to be on-peak hours. Mid-peak hours generally reflected hours when loads were between 85 percent and 90 percent of the daily peak.

The seasonal differentiation within the rates reflect those months that were used to develop the peak allocations in the COSA. The COSA method uses the two highest winter peaks, which typically occur in December or January, and the two highest summer peaks, which typically occur in July or August. The load analysis confirmed this, as the loads for the shoulder months of March through June and September through November were not as high and warranted the use of a mid-peak period.

The load analysis indicated that July/August weekday TOU time periods should be set as follows:

Table 8-4: Summer (July – August) TOU Periods

TOU Period	Effective Hours
On-Peak	12:00 pm – 9:00 pm
Mid-Peak	7:00 am – 12:00 pm
Off-Peak	9:00 pm – 7:00 am Weekends

This contrasts with the current TOU rates, which have a July/August weekday on-peak period from 9:00 am to 11:00 am and from 3:00 pm to 11:00 pm.

No change is proposed to the treatment of weekends, which are presently treated as entirely off-peak. Weekend daytime loads are typically less than for weekdays but often higher than the overnight loads included in the off-peak period. Typically, Saturday loads are 92 percent of weekday loads and Sunday loads are 81 percent of weekday loads

For the December through February period the hourly analysis showed that loads are higher than in the summer months and should include both an on-peak and mid-peak period.

Table 8-5: Winter (December – February) TOU Periods

TOU Period	Effective Hours
On-Peak	7:00 am - 12:00 pm 4:00 pm – 9:00 pm
Mid-Peak	12:00 pm – 4:00 pm
Off-Peak	9:00 pm – 7:00 am Weekends

For the shoulder months, the loads did not rise as much and so the daytime hours are all considered mid-peak. As with the summer period, the off-peak period is proposed to be 9:00 pm to 7:00 am and all day on weekends. The current TOU periods for all other months have an on-peak period of 8:00 am to 1:00 pm and 5:00 pm to 10:00 pm.

Table 8-6: Shoulder (March-June, September-November) TOU Periods

TOU Period	Effective Hours
Mid-Peak	7:00 am - 9:00 pm
Off-Peak	9:00 pm – 7:00 am Weekends

The following summarizes the proposed TOU time periods.

Table 8-7: 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

8.2.2 Time of Use Pricing

The next step in developing the TOU rates is to look at the cost differentials between the TOU periods. For the distribution system, the number of customers and the non-coincident peak of each is used to plan for facilities and this is reflected in the COSA allocations for distribution costs. Costs associated with the transmission and distribution system, while both driven by peak demand, are primarily fixed and cannot be reduced by the time period in which consumption occurs. These do not therefore factor into the derivation of the TOU rate differentials.

Costs for power supply do, however, differ by time-period and were therefore used as the basis for the analysis.

For this purpose, power supply costs for 2016 were split into several different categories to cover capacity-related costs, energy purchases and baseload costs. The capacity costs that are considered variable included the capacity charges related to purchased power and would apply only to the on-peak period. The capacity-related costs are generally associated with ensuring there is sufficient capacity available at the time of the system peaks in the winter and summer. They are charged on the basis of the peak demands in the peak winter and summer months. The on-peak TOU period reflects the timeframe in which that peak demand could occur. While the general hours when a system peak could occur are known, it could occur on any given weekday in the month depending on weather circumstances. For that reason those capacity costs are divided by all of the hours in the on-peak period.

The variable energy costs included the energy charges from power purchases from BC Hydro and the market and apply to both the on-peak and mid-peak period. These charges are incurred for the time periods when loads are higher than what can be generated by FBC's own generation and contractual resources like the Brilliant plant. These charges best match the mid-peak TOU period where loads are expected to be higher than the base load of the system and the load during the potential on-peak hours. All other power costs are considered base costs that would apply to all TOU periods.

The capacity-related costs divided by the on-peak loads yields a per unit cost of 10.57 cents per kWh. This amount was used to reflect the necessary adder for on-peak rates relative to mid-peak rates. The costs and energy amounts used to derive this adder are shown in Table 8-8 below. The variable energy costs are similarly divided by the mid-peak period energy. The result is a per unit cost of 2.59 cents per kWh, which reflects the additional amount for mid-peak rates when compared to off-peak rates. The proposed off-peak rate would be set so that the total forecast revenues collected are revenue neutral with the proposed non-TOU rates and the revenue requirement for each class. The annual cost of the on-peak and mid-peak power supply resources, as well as the energy associated with each is shown in Table 8-8 below. The resulting cost differential is shown in the right-most column.

Table 8-8: TOU Rate Differential Derivation

	Annual Cost	Energy Amount	Cost Differential per kWh
On-Peak Peak Capacity Cost of Both Purchased and Owned Resources	$56 million	530 GWh On-Peak	$0.1057
Mid-Peak Energy Purchases Beyond Output from Owned Resources	$42 million	1,092 GWh Mid-Peak	$0.0259

These pricing differentials form the basis of the TOU rates and are the same for all classes. For each customer class, since the amount of load that falls within each period varies, as does the class revenue requirement, the rates that apply to each class are different.

An elasticity factor was applied to the load in each time-period to account for the assumed impacts in usage associated with TOU rates. The elasticity factor accounts for the assumption that the price difference associated with the time periods will affect customer behaviour. Elasticity estimates were based on the most current data specific to FBC residential customers – those developed for the 2014 RIB report to the BCUC. There, an analysis found an elasticity of -0.14 for block 2 which as a proxy was applied to the on-peak period. The elasticity for the block 1 use was -0.07 (although not statistically significant) and was applied to the mid-peak and off-peak periods. Elasticity was applied to the usage levels and comparing the TOU rates in each period to the average energy rate. The result was a decrease in the on-peak period and on an overall basis. This in turn led to rates that needed to be slightly higher to maintain revenue neutrality to current rates. Additionally, the reduced power supply cost associated with overall reduced consumption was applied as an offset to the revenue when looking at revenue neutrality. The savings was based on the variable energy rate of $0.04863 per kWh from the BC Hydro RS 3808 PPA.

8.3 *PROPOSED TOU RATES*

TOU pricing during the periods described above is built upon a base energy price for each rate class, which is then adjusted based on the time-delineated cost differentials developed as described in the previous section.

Based on the TOU time-periods, the distribution of load into the time periods was developed. The residential breakdown was calculated based on a sample of residential load data. The following shows the split by time period in terms of the percent of load for each class.

Table 8-9: Breakdown of Load to TOU Periods

Rate Class	On-Peak Use	Mid-Peak Use	Off-Peak Use
Residential	15.8%	28.5%	55.8%
Small Commercial	14.3%	34.1%	53.6%
Commercial	14.4%	34.1%	51.5%
Large Commercial	14.0%	33.5%	52.5%
Wholesale Primary	12.4%	32.3%	55.4%
Wholesale Transmission	12.4%	33.8%	53.8%
Irrigation	20.2%	25.8%	54.0%
Total System	**14.9%**	**30.7%**	**54.4%**

Based on the breakdown by time period, the elasticity assumption time-differentiated cost differentials developed as described in the previous section, pricing for each rate class has been developed as follows.

Table 8-10: 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

8.4 TOU RATE IMPLEMENTATION

FBC anticipates that the regulatory process associated with the Application will likely be completed with the issuance of a Commission decision in the fourth quarter of 2018. For most rate changes, implementation can follow at the beginning of the following year – that is, January 1, 2019. Implementation of the proposed TOU rates, which include an additional time period, Mid-Peak, will require additional AMI and billing related system work. If the proposed TOU rates are approved, FBC believes that implementation could reasonably be accomplished on June 1, 2019.

FBC is proposing to track and review the results of the TOU program and after a period of three years, to provide a recommendation to the Commission regarding the continuation of the rates. With respect to customer engagement, FBC is aware that with the phasing in of the flat residential rate and re-introduction of TOU for residential customers, the conservation rate available to residential customers will be changing. FBC's commitment to support conservation efforts on the part of customers through rate design (in accordance with Bonbright Principle #3 "Price signals that encourage efficient use and discourage inefficient use" requires that customers are aware of the availability of the rate and understand how it may be used to encourage conservation and impact customer billing.

While a complete implementation and communication plan cannot be completed prior to receiving Commission approval for the rate itself, FBC envisions that support for customers will include the following broad initiatives:

- Specific mention of the TOU option as part of all Communication related to Approvals related to the Application;
- Increased presence on the www.fortisbc.com website;

- Communication through FBC social media channels;
- Inclusion in outgoing electronic billing communication; and
- Increased awareness by FBC customer service representatives.

The above initiatives can be undertaken at relative little cost. More extensive and costly program enhancements could include specific outreach such as community information sessions and individual billing analysis. However, FBC has not evaluated these options in detail at this time.

9. OTHER RATE SCHEDULES

9.1 SCHEDULE 50 – LIGHTING

FBC is proposing no changes to the lighting rate structures as part of this Application. FBC filed an application for approval of a Type III (Company-owned, Company-maintained) LED street light rate on November 20, 2017.

9.2 SCHEDULES 73 AND 74 - EXTENSIONS

RS 73 is the legacy Extension schedule that is the predecessor to the current RS 74. It has remained part of the Tariff solely to govern the provision to provide contribution refunds in the event that additional customers connect to an extension paid for under RS 73. The allowable time for this provision has elapsed and FBC is therefore proposing to remove this schedule from the Tariff.

FBC's current Extension schedule has been moved from Schedule 74 within FBC's Rate Schedules into the General Terms and Conditions section of the Electric Tariff to align with the organization in FEI's Tariff and to better reflect that the Extension fees and contributions are not impacted by general rate increases. FBC is requesting approval to remove Schedule 74 (Extensions) from the Electric Tariff. Further detail on these changes is contained in Section 10.4 of the Application.

9.3 SCHEDULE 80 – STANDARD CHARGES

The Standard Charges contained in Schedule 80 of FBC's Rate Schedules have been moved into the General Terms and Conditions section of the Electric Tariff to match FEI and to better reflect that the Standard Charges are not impacted by general rate increases. FBC is requesting approval to remove Schedule 80 (Standard Charges) from the Electric Tariff. Further detail on these changes is contained in Section 10.5 of the Application.

9.4 SCHEDULE 81 – RADIO-OFF ADVANCED METER OPTION

The Standard Charges and terms and conditions for the Radio-off Advanced Meter Option contained in Schedule 82 of FBC's Rate Schedules have been moved into the General Terms and Conditions section of the Electric Tariff to match FEI and to better reflect that the Standard Charges are not impacted by general rate increases. FBC is requesting approval to remove Schedule 81 (Radio-off Advanced Meter Option) from the Electric Tariff. Further detail on these changes is contained in Section 10.6 of the Application.

9.5 SCHEDULE 82 – NEW AND UPGRADED SERVICE CHARGES

The Standard Charges contained in Schedule 82 of FBC's Rate Schedules have been moved into the General Terms and Conditions section of the Electric Tariff to match FEI and to better reflect that the Standard Charges are not impacted by general rate increases. FBC is requesting approval to remove Schedule 82 (New and Upgraded Service Charges) from the Electric Tariff. Further detail on these changes is contained in Section 10.5 of the Application.

9.6 SCHEDULE 90 - ENERGY MANAGEMENT

As part of FBC's 2016 Long Term Electric Resource Plan (2016 LTERP) and Long Term DSM Plan (LT DSM Plan), FBC has requested that Schedule 90 be rescinded.[67] FBC is not requesting any changes to Schedule 90 as part of this Application.

[67] 2016 LTERP and LT DSM Plan, Exhibit B-1, Volume 2, Section 5.3, pages 24-26.

10. GENERAL TERMS AND CONDITIONS

10.1 INTRODUCTION

FBC's Electric Tariff General Terms and Conditions (GT&Cs) set out the Commission approved terms and conditions of service provided by FBC. It will be apparent from a review of the revised GT&Cs set out in the black-lined version of the Tariff included as Appendix G, that a significant number of revisions are proposed. However, the majority of the revisions are intended to update and clarify existing language, and where appropriate, to bring commonality with analogous sections in the proposed FEI General Terms and Conditions (GT&Cs) as set out in Appendix 11-1 of the FEI 2016 RDA. Definitions have been added where experience in administering the GT&Cs have indicated a need, and where the current language no longer reflects the operating environment of the Company.

The following Table of Contents sets out the order in which the proposed changes to FBC's GT&Cs are addressed in the Application.

Table 10-1: General Terms and Conditions

Section No.	Section Heading	Page No.
1	Definitions	TC-1
2	Application for Service	TC-6
3	Term of Service Agreement	TC-9
4	Conditions of Service	TC-11
5	Service Characteristics	TC-14
6	Type of Service	TC-17
7	Meter Sets and Metering	TC-19
8	Billing	TC-21
9	Load Changes and Operation	TC-27
10	Continuity of Service	TC-30
11	Rights-of-Way and Access to Facilities	TC-33
12	Customer-owned Generation	TC-35
13	General Provisions	TC-37
14	Repayment of Energy Management Incentives	TC-39
15	Energy Efficiency Improvement Financing	TC-40
16	Extensions	TC-41
17	Standard Charges	TC-45
18	Radio-off Advanced Meter Option	TC-47

10.2 SUMMARY OF PROPOSED AMENDMENTS

The following is a list of the substantive amendments being proposed to the GT&Cs:

- Renaming of FBC's Terms and Conditions (T&C) to General Terms and Conditions (GT&C);
- Regrouping of GT&Cs into smaller subsections for easier referencing;
- Alignment of security deposit policy to match FEI GT&Cs;
- Alignment of applicable Definitions with FEI GT&Cs;
- Updates and increased clarity regarding criteria for Residential Service;
- Updates and increased clarity regarding criteria for Commercial Service;
- Updates and increased clarity regarding criteria for partial Commercial use at Residential Premises;
- Relocation and reorganization of the following Schedules from rate schedules to Terms and Conditions in line with FEI and BC Hydro;
- Updates to and removal of certain Standard Charges to reflect current costs and operating environment.

10.3 GENERAL TERMS AND CONDITIONS

The following sections summarize the changes to the various sections of FBC's General Terms and Conditions, the majority of which are minor housekeeping amendments and reordering of sections. A blacklined version of the General Terms and Conditions is included in Appendix G which shows each change in context

10.3.1 Section 1 (Definitions)

Definitions have been added or moved from the main GT&Cs and rate schedules to provide consistency, clarity, and reduce repetition. These include definitions for Advanced (AMI) Meter, Commercial Service, Landlord, Residential Premises, Residential Service, and Tenant.

10.3.2 Section 2 (Application for Service)

The reasons for refusal of an application for Service is moved to the standalone heading subsection 10.2 (Refusal of Service and Suspension of Service) under GT&C Section 10 (Continuity of Service).

FBC's application for service terms and conditions for rental premises has been updated to match the FEI GT&Cs under subsection 2.4 (Rental Premises). FBC's GT&Cs now include the same provision under FEI's GT&Cs, providing landlords the option of an agreement with FBC to assume responsibility for any non-payment by their tenant.

FBC's security deposit policy has been updated to match FEI's GT&Cs under subsection 2.5 (Security Deposit for Payment of Bills). Changes include the minimum security deposit amount of $50 where previously there was no minimum amount, a change to the calculation of the security deposit amount from three months of estimated consumption to the two highest consecutive months of consumption. In addition, the time period for the return of an unclaimed security deposit to a customer has been increased to ten years from seven.

10.3.3 Section 3 (Term of Service Agreement)

The provision allowing FBC to terminate a service agreement after 48 hours written notice to the customer to match Section 8.5 (Termination by FBC Energy) of FEI's GT&Cs has been added to the FBC GT&Cs in Section 3.3.4 (Termination by FBC). This is a new provision added to FBC's Electric Tariff in order to align with FEI's terms of service.

10.3.4 Section 4 (Conditions of Service)

FBC's existing conditions for connection of a service have been moved from Section 2 (Application for Service) to Section 4 (Conditions of Service) where it more properly resides.

10.3.5 Section 5 (Service Characteristics)

Additional headings have been added to Section 5 (Service Characteristics) for clarity and ease of reference.

FBC has included the condition allowing the Company to determine the amperage of a service connection under Section 5.1 (Voltages Supplied).

10.3.6 Section 6 (Type of Service)

The existing conditions regarding the construction, conversion and salvage of temporary service facilities have been moved from the Schedule 80 standard charges schedule to Section 6.1 (Temporary Service).

FBC's GT&Cs previously set out multiple single- and multiple- metered residential premises scenarios. These scenarios have been simplified and moved from the GT&Cs to the Residential Premises definition in Section 1 (Definitions).

Section 6.3.1 (Partial Commercial Use) has been revised to require that any Residential customers with Commercial use at their Residential Premises must have a separate meter for the Commercial area in order to qualify for a Commercial rate. FBC's previous guidelines governing partial commercial use at a residential property were put in place when Residential rates were lower than Commercial rates, which is no longer the case. FBC has updated its partial commercial use policy to properly reflect the current Residential/Commercial rate differential. The new partial commercial use policy also eases the administrative burden to FBC of determining on a case by case basis whether a Residential customer qualifies for Commercial service.

10.3.7 Section 7 (Metering)

Additional headings have been added to Section 7 (Metering) for clarity and ease of reference.

10.3.8 Section 8 (Billing)

Additional headings have been added and reordering of sections within Section 8 (Billing) for clarity and ease of reference.

Section 8.1 (Basis for Billing) has been added to match FEI GT&Cs Section 16.1 (Basis for Billing).

Section 8.2.1 (Customer Selected Bill Date) has been amended to clarify that FBC will send bills to the customer as close to their selected bill date as possible. The reason for the addition is to reflect occasions where a customer's selected bill date cannot be accommodated, for example:

- where a Customer's selected bill date falls on a weekend;
- where a Customer's selected bill date falls on a statutory holiday;
- where a Customer's selected bill date does not exist (i.e. 31st day in a month with 30 days); and

Section 8.7 (Back-billing) has been updated with additional headings for clarity and ease of reference. Subsection 8.7.1 (When Required) has been added to match FEI GT&Cs Section 19.1 (Where Required). Subsection 8.7.5 (Tampering/Fraud) has been updated to include the condition that a reasonable customer should have known of the under-billing to reflect the same conditions in FEI's GT&Cs Subsection 19.5 (Tampering/Fraud).

10.3.9 Section 9 (Load Changes and Operation)

No changes were made to Section 9 (Load Changes and Operation).

10.3.10 Section 10 (Continuity of Service)

FBC's terms and conditions for refusal and/or suspension of service have been included in a standalone section with its conditions regarding interruptions and defects in service. Previously these conditions were included in many sections throughout the Electric Tariff. Including these terms and conditions into its own standalone section matches FEI's GT&Cs Section 23 (Discontinuance of Service and Refusal of Service).

10.3.11 Section 11 (Rights-of-Way and Access to Facilities)

Section 11.2 (Access) has been updated to include conditions regarding the obstruction of radio-frequency technology for the purpose of interfering, attenuating or degrading the signal. This addition reflects FBC's move to remote meter reading through its AMI infrastructure. In addition, the conditions regarding the levying of the False Site Visit charge has been moved from Schedule 80 Standard Charges to Section 11.2 (Access).

10.3.12 Section 12 (Customer-Owned Generation)

No changes were made to Section 12 (Customer-Owned Generation).

10.3.13 Section 13 (General Provisions)

No changes were made to Section 13 (General Provisions).

10.3.14 Section 14 (Repayment of Energy Management Incentives)

No changes were made to Section 14 (Repayment of Energy Management Incentives).

10.3.15 Section 15 (Energy Efficiency Improvement Financing)

No changes were made to Section 15 (Energy Efficiency Improvement Financing).

10.4 *SECTION 16 (EXTENSIONS)*

FBC's Extension schedule has been moved from Schedule 74 within FBC's Rate Schedules into the General Terms and Conditions section of the Electric Tariff to match FEI and to better reflect that the Extension fees and contributions are not impacted by general rate increases.

The specific definitions pertaining to extensions have been moved from Schedule 74 to Section 1 (Definitions). Additional headings have been added and reordering of subsections within Section 16 (Extensions) for clarity and ease of reference.

Section 16.5 (Designing and Estimating) has been updated to clarify that applicants for an extension can choose a pre-approved contractor to both design and/or construct, where previously applicants could only a choose a pre-approved contractor to construct the extension.

The contribution amounts to a Customer's extension based on their Rate Schedule under Subsection 16.3.1 (FBC Contribution) have been updated. The calculation of the new credit amounts is set out in the EES COSA Report (Appendix A).[68] The following table sets out the current and updated contribution amounts.

[68] Table 13 – Line Extension Credits, pages 44 and 45.

Table 10-2: 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

10.5 *SECTION 17 (STANDARD CHARGES)*

The Standard Charges have been moved from Schedule 80 and 82 within FBC's Rate Schedules into the General Terms and Conditions section of the Electric Tariff to align with the organization of the standard charges in FEI's GT&Cs and to better reflect that the Standard Charges are not impacted by general rate increases.

FBC reviewed the current costs and operating practises for these services, as well as similar charges contained in the FEI and BC Hydro Tariffs. The Standard Charges were last updated as part of the 2009 COSA and RDA and were based on operations and costs from 2008. Each of the Standard Charges changes is discussed below.

10.5.1 Subsection 17.1 Installation of New/Upgraded Services

This section was previously Schedule 82 Installation of New/Upgrade Services. The minimum connection charges for overhead and underground services have been updated to reflect current costs. FBC is proposing to remove the minimum connection charge for a 400 amp service to reflect that FBC already must develop a design and estimate of any service that is in excess of 200 Amps.

Table 10-3: 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

The derivation of the proposed updated charges can be found in Appendix D.

10.5.2 Subsection 17.2 Connection Charges

This section was previously contained in Schedule 80 Charges for Connection or Reconnection of Service, Transfer of Account, Testing of Meters, and Various Custom Work. The Connection charges have been updated to reflect current costs.

Table 10-4: 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

The derivation of the proposed updated charges can be found in Appendix D.

10.5.3 Subsection 17.3 Miscellaneous Standard Charges

This section was previously contained in Schedule 80 Charges for Connection or Reconnection of Service, Transfer of Account, Testing of Meters, and Various Custom Work. The Connection charges have been updated to reflect current costs. The Collection Charge has been removed from the standard charges to reflect that FBC does not charge this fee.

Table 10-5: 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

[69] Manual reconnection fees apply to those customers taking service under the Radio-off Meter Option.

[70] Remote reconnection fees apply to all customers with radio-on AMI meters and those customers with non-communicating radio-on AMI meters.

Standard Charge Name			
Current	Proposed	Current	Proposed
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

The derivation of the proposed updated charges can be found in Appendix D.

10.5.4 Subsection 17.4 Custom Work

This section was previously contained in Schedule 80 Charges for Connection or Reconnection of Service, Transfer of Account, Testing of Meters, and Various Custom Work. FBC is not proposing any additional changes to this section.

10.6 *Section 18 (Radio-off Advanced Meter Option)*

This section was previously contained in Schedule 82 Radio-off Advanced Meter Option. The definitions contained in Schedule 82 Radio-off Advanced Meter Option have been moved to Section 1 (Definitions). The Pre-Commencement of Deployment Setup Fee has been removed because the AMI Project deployment is complete and the fee is no longer relevant. FBC has updated the per-read fee to reflect current costs and operations. FBC also proposes to recover the projected 2018 balance of $0.120 million in the AMI Radio-Off Shortfall Deferral Account over the five-year period 2019 – 2023[71] and to revisit the read fee in its next RDA.

Table 10-6: AMI Radio-Off Fees

	Current	Proposed
Pre-Commencement of Deployment Setup Fee	$60	Removed
Per-Premise Setup Fee	$88	$88
Per-Read Fee	$18	$25

The derivation of the proposed updated charges can be found in Appendix D.

[71] FBC identified in its Annual Review for 2016 Rates that the approved tariff fees for radio-off customers are not sufficient to recover the costs associated with providing the service, and stated in response to BCUC IR 1.12.4 (Exhibit B-2) that its preferred approach was to recover the costs from all customers until the fees could be reset, in part because of the potential for a significant increase to the fees. The Commission denied FBC's request to recover the costs in general rates pending the submission of FBC's AMI Radio-Off Report on September 30, 2016. In its Annual Review for 2017 Rates, FBC stated its intention to propose the disposition of the deferral account in this RDA. The impact of recovering the projected balance over the proposed five-year period is $1.48 per meter read ($0.120 / 5 years = $0.024 / 16,146 reads per year = $1.48 per read).

Appendix A

EES CONSULTING COSA REPORT

FortisBC

Electric Cost of Service Study

December 22, 2017

Prepared by:

EES Consulting

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December 22, 2017

Mr. Corey Sinclair
FortisBC
1975 Springfield Road, Suite 100
Kelowna, BC V1Y 7V7

SUBJECT: Electric Cost of Service Study

Dear Mr. Sinclair:

Please find attached the report of the Electric Cost of Service Study prepared by EES Consulting, Inc. (EES). The conclusions and recommendations contained within this report are based upon industry practice and generally accepted rate setting principles

This study has been developed through the mutual assistance of FortisBC staff. The findings, conclusions and recommendations of this report provide the basis for the development of fair and equitable rates for FortisBC.

Thank you for the opportunity to assist FortisBC in this rate setting process. Please contact me directly if there are any questions about the subject analyses.

Very truly yours,

Gary Saleba
President

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Executive Summary

EES Consulting, Inc. (EES) was retained by FortisBC to perform a comprehensive electric cost of service analysis (COSA). The COSA is one of the major inputs that will be used in developing proposed rates for FortisBC. The COSA takes the revenue requirements established for the utility and allocates costs across the various customer classes, with the results used to ensure that proposed rates are fair, equitable and not unduly discriminatory.

FortisBC last filed a comprehensive COSA in 2009 and with final rates accepted and approved in 2010 with additional recommendations. The methodology from the 2009 COSA was considered as a starting point when performing the 2017 COSA. Changes that have occurred over the past 8 years in terms of the FortisBC system, changes in the overall electric industry, and trends in utility ratemaking were all considered when developing this COSA.

Overview of the COSA

The COSA takes the revenue requirement for the utility and attempts to equitably allocate those costs to the various customer classes of service (i.e., residential, commercial, etc.). This analysis provides a determination of the level of revenue responsibility of each class of service and the adjustments required to meet the cost of service.

There are three basic steps to follow in developing a COSA, namely:

- Functionalization
- Classification
- Allocation

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, transmission, distribution, and general.

Classification determines the portion of the cost that is related to specific cost-causal factors, such as those that are demand-related, energy-related, or customer-related. Production costs are related to supplying power to customers on the system. Production facilities are designed and operated to meet system peak demands and total energy requirements. Transmission costs are related to the bulk transfer of power to load centres on the system. These transmission facilities are typically designed and operated to meet system peak demand requirements. The distribution system is designed to extend service to all customers attached to the system and to meet the peak load capacity requirement of each customer.

Allocation of costs to specific customer classes is based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the particular measurement of system demand, whether coincident peak, non-coincident peak or some variation determined to be appropriate for the particular cost item. An analysis of customer requirement, loads, and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA. The analysis may include an evaluation of the system design and operations, its accounting and physical asset records and detailed studies of customer load data.

FortisBC Revenue Requirement and Rate Base

A revenue requirement analysis compares the overall revenues of the utility to its expenses and determines the overall adjustment to rate levels that is required. The revenue requirement is the starting point of the COSA, with all items in the revenue requirement allocated across the various customer classes. The rate base for the utility is also an important component when developing the revenue requirement. Capital spending is included in the rate base. Only approved capital expenditures are included in the rate base. The allowed return on rate base is a major component of the revenue requirement.

For purposes of this COSA, the 2017 Forecast Revenue Requirement for FortisBC was used. The source for this forecast was the October 5, 2016 Evidentiary Update. The total approved revenue requirement is $360.7 million, which includes an offset of $9.5 million in revenues from sources other than electric rates.

The accompanying rate base associated with the 2017 revenue requirement is $1.28 billion. The rate base reflects gross plant of $1.9 billion, which is offset by accumulated depreciation and customer contributions. Distribution makes up 52% of gross plant, followed by 23% for transmission, 12% for power production and 13% for general plant.

FortisBC is projecting total customers of 133,853 on average for 2017 and gross energy consumption of 3.3 million MWh. Residential customers make up 86 percent of the total number of customers and over 41 percent of energy sales. Wholesale customers make up another 18 percent of energy, with the remaining 41 percent related to various commercial and other retail classes.

The peak is forecast to occur in the winter at 761 MW and peak of 634 MW is expected during the summer months.

Major Assumptions of the COSA

The following provides some of the major assumptions and underlying data used in conducting the COSA for FortisBC.

Customer classes of service refer to the arrangement of customers into groups that reflect common usage characteristics or facility requirements. FortisBC serves five customers at the wholesale level, including Penticton, Summerland, BC Hydro at Kingsgate and Kaslo, Grand Forks and Nelson. Wholesale customers are split by service level with separate classes for those served at primary and transmission level service. Nelson is the only customer served at transmission level service.
The classes of service analyzed in the study were as follows:

- Residential
- Small Commercial (Rate 20)
- Commercial (Rate 21 and 22)
- Large Commercial Primary (Rate 30 and 32)
- Large Commercial Transmission (Rate 31)
- Lighting
- Irrigation
- Wholesale Primary (Rate 40)
- Wholesale Transmission (Rate 41)

Key assumptions include:

- Forecast year 2017 was selected as the test period for the allocation of costs.

- The 2017 forecast revenue requirement as contained in the Evidentiary Update.

- Monthly power supply costs were classified as demand and energy on the basis of wholesale Rate 3808 from BC Hydro and allocated on a monthly basis.

- Distribution plant was classified based on a "minimum system" approach. A peak load carrying capability (PLCC) credit was applied to correct for the inherent double-counting of demand costs with the standard minimum system study.

- Demand-related transmission costs were allocated using the 2 CP (coincident peak) method (sum of 2 winter and 2 summer peaks).

These assumptions are discussed in greater detail throughout this report.

Summary of Results

Given the above assumptions regarding the COSA, the various costs were classified and allocated to the customer classes. This section provides the results of the COSA in summary form. Detailed tables reflecting all of the COSA details can be found in Appendix A.

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

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

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

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

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

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

A summary comparison of the revenues at present rates, allocated cost of service and resulting revenue to cost ratios can be found in Schedule 1.1 of Appendix A. The resulting revenue to cost (R/C) ratios are shown in Table ES-1:

Table ES-1 COSA Revenue to Cost Ratios	
	Adjusted Revenue to Cost Ratio
Residential	98.4%
Small Commercial 20	102.2%
Commercial 21/22	104.7%
Large Commercial Primary 30/32	104.0%
Large Commercial Transmission 31	107.0%
Lighting	92.2%
Irrigation	97.2%
Wholesale Primary 40	96.7%
Wholesale Transmission 41	103.9%
Total	100.0%

The proposed range of reasonableness of 95 to 105 percent is proposed in this application, which is consistent with the last COSA and resulting Commission Order.[1] The majority of rate classes fall within this range and therefore do not need rebalancing. The Large Commercial – Transmission rate (Rate 31) has an R/C ratio above the range while the Lighting class has an R/C ratio below the range. It would be appropriate to rebalance these two classes to move towards the COSA results.

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

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[1] G-156-10

Overview and Basis for the COSA

EES Consulting, Inc. (EES) was retained by FortisBC to perform a comprehensive electric cost of service analysis (COSA). The COSA is one of the major inputs that will be used in developing proposed rates for FortisBC. The COSA takes the revenue requirements established for the utility and allocates costs across the various customer classes, with the results used to ensure that proposed rates are fair, equitable and not unduly discriminatory.

FortisBC last filed a comprehensive COSA in 2009, with that rate proceeding resulting in rates that were implemented in 2011. Rates have had across-the-board increases periodically to reflect approved revenue requirements increases. The methodology from the 2009 COSA was considered as a starting point when performing the 2017 COSA. Changes that have occurred over the past 8 years in terms of the FortisBC system, changes in the overall electric industry, and trends in utility ratemaking were all considered when developing this COSA.

This report is organized such that it follows the steps taken in analyzing and developing FortisBC’s COSA. Contained in this section is a discussion of the theory and financial principles behind setting rates. Also included is a summary of the underlying financial results used as the basis for the COSA. The next section discusses the COSA and the results of that process, including the methodology used to allocate costs between customer classes. The final section provides a summary of the COSA results. Additionally, there is a section including a review of both COSA methods and rate designs in other Jurisdictions.

A technical appendix is attached at the end of this report that provides the details associated with the COSA for FortisBC. The schedules contained in Appendix A are referenced throughout the report. Appendices B and C provide more details associated with the COSA inputs.

Overview of the COSA

The setting of electric utility rates that are “fair and equitable” is a complex process. This process is directed, however, by generally accepted methodologies that can be used as a guide in developing FortisBC’s electric rates. At the same time, there are often a number of financial principles or guidelines that must be taken into consideration during this process. Therefore, the setting of electric rates that are “fair and equitable” is an integration of these generally accepted methodologies and any related financial policies or specific policy considerations from FortisBC.

The COSA analysis takes the revenue requirement for the utility and attempts to equitably allocate those costs to the various customer classes of service (i.e., residential, commercial). This analysis provides a determination of the level of revenue responsibility of each class of service and the adjustments required to meet the cost of service.

Costs are allocated to the various customer classes of service based upon a fair and equitable methodology that reflects the cost-causal relationships for the production and delivery of the services. A COSA begins by "functionalizing" a utility's revenue requirement as power supply, transmission, distribution and general. Next, the functionalized costs are "classified" to demand-, energy-, and customer-related component costs. Demand-related costs are those that the utility incurs to meet a customer's maximum instantaneous usage requirement, and is usually measured in kilowatts (kW). Energy-related costs are those that vary directly with longer periods of consumption and are usually measured in kilowatt-hours (kWh). Customer-related costs are those that vary with the number and type of customers served.

These three component costs are then "allocated" to each class of service based upon the most equitable method for each specific cost. At that point, the revenue requirement has been allocated to each class of service and a determination of the necessary revenue adjustments between classes of service can be made. The final step is the calculation of demand, energy and customer unit costs for each class of customer or rate schedule. These unit costs provide valuable input into the rate design process.

FortisBC Revenue Requirement

A revenue requirement analysis compares the overall revenues of the utility to its expenses and determines the overall adjustment to rate levels that is required. The revenue requirement is the starting point of the COSA, with all items in the revenue requirement allocated across the various customer classes. The rate base for the utility is also an important component when developing the revenue requirement. Only approved expenditures are included in the rate base. The allowed return on rate base is a major component of the revenue requirement.

For purposes of this COSA, the most current data, the 2017 Forecast Revenue Requirement, for FortisBC was used. This revenue requirement was approved by the Commission and was provided in the October 5, 2016 Evidentiary Update for 2017. The total approved revenue requirement for 2017 is $362.1 million. The following summarizes the approved revenue requirements forecast for 2017.

	Millions
Cost of Energy	$152.2
O&M and A&G Expenses	48.2
Return, Depreciation and Taxes	169.8
Less Other Revenue	-8.1
Net Revenue Requirements	362.1
Less Rate 37 Revenues	1.4
COSA Revenue Requirements	$360.7

Roughly 46% of the revenue requirement is related to return on rate base, taxes and depreciation. Another 41% is for the cost of energy. The remaining 13% is for O&M expenses of the utility. The approved revenue requirement is the basis for the rates that are currently in place for FortisBC for the year 2017. Schedule 3.1 in Appendix A provides a summary of the approved revenue requirement.

For the purposes of the COSA, an additional $1.4 million in revenues from Standby Rate 37 was deducted from the revenues requirements. This offset was made to reflect the fact that the Rate 37 sales are for standby power sold to one of FortisBC's Rate 31 customers. The customer takes 3 MW of standard firm power under Rate 31 and those sales are included in the Rate 31 rate class. Because the standby sales are sold at rates below the full embedded cost resulting from the COSA, it was determined that the revenues should be treated as an offset to the revenue requirements and allocated to all customers to compensate for the use of the system paid for by all customers, including those within Rate 31. The energy and demand associated with the Rate 37 standby sales are also left out of the Rate 31 class amounts and the total system amounts.

Revenue requirements at the time of the 2009 COSA were $235.4 million and were broken down as 30% purchased power costs, 20% O&M costs and 50% for return, depreciation and taxes. The cost of energy has become a larger component of costs for FortisBC, while O&M costs have become a smaller percent of the total.

This COSA is based on a forecast test year approved in 2016 and has not been updated to reflect any actual costs, sales or revenues for 2017 year-to-date. The use of a forecast year allows for a more standardized basis as it assumes normal weather conditions and stable economic conditions, and does not include any extraordinary costs for the year.

Rate Base

The accompanying mid-year rate base associated with the 2017 revenue requirement is $1.28 billion. The rate base reflects gross plant of $1.9 billion, which is offset by accumulated depreciation and customer contributions. Distribution makes up 52% of gross plant, followed by 23% for transmission, 12% for power production and 13% for general plant. The mid-year rate base is summarized as follows:

	Millions
Total Gross Plant	$1,943.2
Less Accumulated Depreciation	-577.3
Less Customer Contributions	-112.9
Working Capital, Deferred and Other	31.5
Total Rate Base	$1,284.5

Schedule 4.1 of Appendix A provides the detailed rate base for FortisBC by account used for the COSA.

The 2009 rate base of $908.0 million compares to the 2017 rate base of $1.28 billion. In 2009 the split was 46% distribution, 29% transmission, 13% production and 12% general plant. Distribution plant has grown relative to the other rate base functions.

Projected Load Forecast

FortisBC's projected customers and sales per class, as provided in the Evidentiary Update, are presented in Schedule 8.1 of Appendix A. FortisBC is projecting total customers of 133,853 on average for 2017 and gross energy consumption of 3.3 million MWh. Residential customers make up 86 percent of the total number of customers and 41 percent of energy sales. Wholesale customers make up another 18 percent of energy, with the remaining 41 percent related to commercial, industrial and other retail classes.

	GWh
Residential	1,353.8
Other Retail	1,341.2
Wholesale	587.3
Total System	3,282.3

The peak forecast is expected to occur in the winter of 761 MW and a peak of 634 MW is expected during the summer months.

In 2009 the total system energy was 3,107 GWh forecast for the year. This reflects an average annual increase of 0.7% per year. The number of customers, however, has increased by an average of 2.3 percent per year. The difference in the customer growth and energy sales growth is due in part to a change in the mix of customer types and the average use per customer. Wholesale sales also changed significantly due to the FortisBC purchase of the City of Kelowna electric utility.

Projected Revenues

FortisBC provided revenues by class for the 2017 Revenue Requirement. These revenues were calculated using an average rate for each class, consistent with the method used in past years. For purposes of the COSA, revenues were calculated under each tariff based on the billing determinants for each class, with the following results:

	Millions
Residential	$185.1
Other Retail	127.7
Wholesale	49.2
Total Revenues	362.0
Less Rate 37 Revenues	-1.4
Net Revenues	$360.5

Using the revenues at approved rates for the 2017 Evidentiary Update and adding the allowed 2017 rate increase results in projected revenues of $362.1 million. The calculated revenue from rates in the COSA using the actual billing determinants times the various rate components is $362.0 million, which is 0.38% lower than the revenue requirements provided in the Evidentiary Update. FortisBC believes the updated calculation is appropriate for projecting revenues for the COSA and for future rate filings.

The Rate 37 standby revenues are then subtracted from the revenue totals above because they are treated as other revenues. Schedule 8.1 of Appendix A provides the revenues projected for each class.

Jurisdictional Review of COSA Methodology

To assist in determining whether FortisBC is using accepted methods within its COSA, EES reviewed the methods used by various other electric utilities across Canada. While physical circumstances, intervener positions, Commission approvals and history all play a role in approved COSA methods for different utilities, it is useful to review what other utilities are using. The review of the methods used by other large electric utilities is based primarily on the Commission Decisions in the most recently approved rate cases. In some cases, the Decision is still pending or a settlement was reached among the parties and the methods contained in the rate application were included.

The utilities included in the review are:

- BC Hydro
- ATCO Electric Alberta
- Fortis Alberta
- Manitoba Hydro (Manitoba)
- Hydro Quebec (Quebec)
- Nova Scotia Power (Nova Scotia)
- Newfoundland Power
- New Brunswick Power

EES also spoke to a representative at SaskEnergy, however, they are not regulated in the traditional sense and their COSA is not publicly available.

Because BC Hydro completed a very thorough review of methods in its most recent RDA, that level of detail is not repeated here. In some cases, the BC Hydro supplied information was used to complete our review. FortisBC is not proposing to change its COSA methodology from the last approved RDA and is not relying on precedents in other jurisdictions to support its proposed COSA methods.

While we were able to compare specific methods used in the COSA, in some cases it would be difficult to say that there was a true precedent as the Decision is still pending or the results were based on a negotiated settlement. Further, there was a broad range in methods used by different utilities and in many cases there was not a clear standard practice used.

Table 1 summarizes the status of each rate proceeding and the related dates associated with the Application and Decision

Table 1 Status of Most Recent Rate Application			
Name of Utility	**Timeline**	**Docket**	**Status**
BC Hydro	2016	Decision G-47-16 Decision G-5-17	Negotiated Settlement on COSA followed by Decision on Rate Design
ATCO Electric Alberta	2011	Decision 2011-483	Negotiated Settlement
Fortis Alberta	2013	Decision 2014-018	Full Application and Decision
Manitoba Hydro	2012	2013/2014 General Rate Application	Full Application and Decision
Hydro Quebec	2012	Demand R-3814-2012	Full Application and Decision
Nova Scotia Power	2013	2014 NSUARB 53 M05473	Full Application and Decision
Newfoundland Power	2012	2013/2014 General Rate Application	Full Application and Decision
New Brunswick Power	2017	Matter 0336	Full Application and Decision

Cost of Production and Power Supply

The treatment of generation and power supply costs was not consistent. In most cases there was some split between demand and energy, as used by FBC, but the percentages varied significantly.

In Alberta, there is a retail market for power supply and costs are flowed through using hourly settlement prices. In a few other cases, hourly or time of use allocations were used. The system load factor was sometimes used to classify costs between demand and energy. Other splits were more arbitrary. In most cases demand-related costs were based on the coincident peak, but it varied from 1CP to 3CP to 4 CP. A summary of the various treatments used by other utilities can be found in Table 2.

While FBC's approach uses the equivalent cost of the BC Hydro RS3808 supply to classify between demand and energy and the use of the 2CP allocator is not exactly the same as any other utility, it is consistent overall with a classification split between demand and energy and CP approach used by most.

Table 2 Treatment of Generation/Power Supply	
Name of Utility	**Method Used**
BC Hydro	45% Energy and 55% Demand (same as 2007 RDA Decision) for Heritage Hydro, Capital and operating cost at 100% demand and fuel at 100% energy for Burrard, and load factor method for other thermal plants, 7% demand, 93% energy based on value of capacity from IPP plants, Use of 4CP averaged over 5 years as allocator for demand component.
ATCO Electric Alberta	Hourly settlement costs allocated based on hourly use by zone
Fortis Alberta	Load settlement costs based on settlement sites by class
Manitoba Hydro	Generation and Purchased Power 100% energy with weighted energy non-peaking related allocation factors for three TOU periods
Hydro Quebec	Purchased Power 100% Energy but cost in each hour allocated on loads in each hour, load factor method for heritage resources with 1CP
Nova Scotia Power	System Load Factor and 3CP for baseload, 90% energy for wind,
Newfoundland Power	Purchased power on underlying method of supplier – system load factor for hydro resources and a combination of plant capacity factor and demand-only methods for thermal generation with 1 CP
New Brunswick Power	47% on Peak Demand, 53% on average demand (energy)

Transmission

Treatment of transmission was the most consistent among utilities, with the majority using a 100% demand approach. The approach used for the demand allocator did vary among utilities. Table 3 summarizes the treatment of transmission costs in the COSA of the utilities reviewed.

Table 3 Treatment of Transmission	
Name of Utility	**Method Used**
BC Hydro	Generation-Related treated same as Hydro resources, transmission 100% demand related with 4CP allocation averaged over 5 years.
ATCO Electric Alberta	Differs by wholesale charges – bulk rate on CP demand, POD and local system charges on POD capacity demand, energy charges on energy
Fortis Alberta	Differs by wholesale charges – bulk rate on CP demand, POD and local system charges on POD hourly load data, energy charges on energy
Manitoba Hydro	100% Demand-related with Average of highest 50 peak hours
Hydro Quebec	100% Demand-related with NCP
Nova Scotia Power	System Load Factor with 3CP
Newfoundland Power	100% Demand-Related with 1 CP
New Brunswick Power	100% Demand

Distribution System

While several of the utilities used a minimum system approach, like FBC, others had specific classification splits between demand and customer that varied by utility. The use of the NCP allocator for the demand-related component was the most common. The one exception was Fortis Alberta, where a specific analysis was done to assign feeders to the classes they served. Table 4 summarizes the treatment of distribution mains in the COSA of the utilities reviewed.

Table 4
Treatment of Distribution System

Name of Utility	Method Used
BC Hydro	Substations and Primary = 100% Demand, Transformers, Secondary and Services = 50% Demand/50% Energy, Meters 100% Customer. Net result of 27% customer and 73% demand.
ATCO Electric Alberta	Poles and Conductors 30% Demand/70% Customer, Underground 55% Demand/45% customer, transformers 40% demand/60% customer. Meters and services 100% customer with weighted customers. Substations 100% demand, NCP used for demand allocator
Fortis Alberta	CAM method – allocates property for 100 distribution feeders to the individual sites being served, meters on weighted customers
Manitoba Hydro	Substations and transformers 100% demand, lines based on 1990 study with 1 NCP allocation and weighted customers
Hydro Quebec	Meters, services and transformers 100% customer, substation 100% demand, minimum system for rest with 12 NCP allocation and weighted customers
Nova Scotia Power	Poles split 65% primary and 35% secondary, then 30% of primary to demand and 70% equally between demand and customer service. Secondary split equally between demand and customer service. Wires split 70% primary and 30% secondary, then same classification as poles.
Newfoundland Power	Minimum system analysis, with transformers at zero intercept with 1 NCP allocation and weighted customers
New Brunswick Power	Poles & wires 50% demand, 50% customer, transformers 75% demand 25% customer, metering on weighted customers, demand uses NCP

Customer Accounting/Customer Care

Table 5 summarizes the treatment of customer accounting and customer care in the COSA of the utilities reviewed. Customer accounting costs were considered customer-related in all cases. However, in most cases there was some type of weighting used for customers. Often the weighting involved the use of revenues for a small portion of the allocation.

Table 5 Treatment of Customer Care	
Name of Utility	**Method Used**
BC Hydro	100% Customer Related but allocated based on 90% on customers and 10% on revenues to reach weighted average
ATCO Electric Alberta	Level of effort per customer class
Fortis Alberta	80% number of customers, 20% on revenues
Manitoba Hydro	Not available
Hydro Quebec	Not available
Nova Scotia Power	Weighted customers with 85% customer/15% revenues
Newfoundland Power	Not available
New Brunswick Power	100% customer-related using weighted customer allocation.

Demand Side Management/Conservation

Table 6 summarizes the treatment of demand side management (DSM) or conservation in the COSA of the utilities reviewed. Not all of the utilities had specific costs related to DSM that were discussed. For those that did, costs were generally recognized, at least in part, as avoided generation costs and there treated like generation.

Table 6 Treatment of Demand Side Management/Conservation	
Name of Utility	**Method Used**
BC Hydro	90% Generation, 5% Transmission and 5% Distribution
ATCO Electric Alberta	Not available
Fortis Alberta	Not available
Manitoba Hydro	Not available
Hydro Quebec	Not available
Nova Scotia Power	Not available
Newfoundland Power	13% generation, 10% transmission, 59% distribution, 18% customer care for general costs, 97% generation, 3% transmission for development of measures, 100% generation for customer incentives
New Brunswick Power	50% system related and follows production. 50% assigned to customer classes.

Cost of Service Analysis

The objective of the COSA is to analyze costs and equitably assign those costs to customers commensurate with the cost of serving those customers. The founding principle of cost allocation is the concept of cost-causation. Cost-causation evaluates which customer or group of customers causes the utility to incur certain costs by linking system facility investments and operating costs to serve certain facilities to the services used by different customers. This section of the report will discuss the general approach used to perform the FortisBC COSA, using the FortisBC approved 2017 revenue requirement, and provide a summary of the results.

COSA Overview and General Principles

A COSA allocates the costs of providing utility service to the various customer classes served by the utility based upon the cost-causal relationship associated with specific expense items. This approach is taken to develop a fair and equitable assignment of costs to each customer class so that customers pay for the costs that they cause. Because the majority of costs are not incurred by any one type of customer, the COSA becomes an exercise in spreading joint and common costs among the various classes using factors appropriate to each type of expense. The COSA is the second step in a traditional three-step process for developing service rates. The first step is the development of the test period revenue requirement for the utility, which is the starting input for the COSA. The COSA spreads the revenue requirement across the various customer classes, creating per unit costs by class. In the third step, rates are designed for each customer class, with per unit costs being one consideration in setting the appropriate rate levels.

A COSA can be performed using embedded costs or marginal costs. Embedded costs generally reflect the actual costs incurred by the utility and closely track the costs kept in its accounting records. Marginal costs reflect the cost associated with adding a new customer, and are based on costs of facilities and services if incurred at the present time. While marginal costs can be valuable for designing rates in certain instances, marginal costs are generally higher than embedded costs. Therefore, the use of a marginal COSA usually requires that all costs be scaled back to a level equal to the embedded cost revenue requirement established using actual or projected costs from an “accounting” perspective.

This study uses an embedded COSA as its standard methodology. Therefore, FortisBC’s embedded cost revenue requirement and existing rate base investment are used in developing the COSA results.

There are three basic steps to follow in developing a COSA, namely:

- Functionalization
- Classification
- Allocation

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, transmission, distribution, and general.

Classification determines the portion of the cost that is related to specific cost-causal factors, that are demand-related, energy-related, or customer-related. Production costs are related to supplying power to customers on the system. Production facilities are designed and operated to meet system peak demands and total energy requirements. Transmission costs are related to the bulk transfer of power to load centres on the system. These transmission facilities are typically designed and operated to meet system peak demand requirement. The distribution system is designed to extend service to all customers attached to the system and to meet the peak load capacity requirement of each customer.

Allocation of costs to specific customer classes is based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the particular measurement of system demand, whether coincident peak, non-coincident peak or some variation determined to be appropriate for the particular cost item. An analysis of customer requirements, loads, and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA. The analysis may include an evaluation of the system design and operations, its accounting and physical asset records, customer load data, and special studies.

Actual load data for 2016 was used for the development of the various allocation factors. Details about how the load data was collected and used is included in Appendix C.

While this section does not address the design of rates, it is important to note that the COSA results will be one of the considerations when the process of designing rates for various customer classes begins.

Major Assumptions of the Cost of Service Analysis

The 2009 COSA as a starting point for the 2017 COSA and the methodologies used are consistent with the 2009 approach that formed the basis for the rates approved by the Commission at that time. The following provides some of the major assumptions and underlying data used in conducting the 2017 COSA for FortisBC.

Customer classes of service refer to the arrangement of customers into groups that reflect common usage characteristics or facility requirement. The classes of service used within this study were as follows:

- Residential
- Small Commercial
- Commercial
- Large Commercial Primary
- Large Commercial Transmission
- Irrigation
- Lighting
- Wholesale Primary
- Wholesale Transmission

Note that while some of the rate classes also have a separate time of use (TOU) rate, those customers were combined with the underlying class for the rate. This is partly due to the fact that there are very few TOU customers and partly because the embedded COSA does not differentiate costs by TOU period.

Key assumptions include:

- Forecast year 2017 was selected as the test period for the allocation of costs.

- The 2017 forecast revenue requirement was based on the October 5, 2016 Evidentiary Update for 2017.

- Actual load data for 2016 was used as the starting point for developing allocation factors. With FortisBC's new AMI system it was possible to collect the necessary hourly loads by class to develop various types of peak demands.

- Monthly power supply costs were classified as demand and energy on the basis of wholesale Rate 3808 from BC Hydro and allocated on a monthly basis to various customer classes.

- Demand-related transmission costs were allocated using the 2 CP method (sum of 2 winter and 2 summer peaks) to take the significance of the growth in summer peak into consideration.

- Distribution plant was classified 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.

These assumptions are discussed in greater detail throughout this report. Given the key assumptions, the COSA could be completed. The following sections provide the specific treatment of items within the COSA, along with the results of the COSA.

Functionalization of Costs

The first step in the COSA process is to functionalize the rate base and revenue requirement. Functionalization is the separation of cost data into the functional activities performed in the operation of a utility system (i.e., power supply, transmission, distribution and general). Functionalization was accomplished using FortisBC's system of accounts for both the rate base and revenue requirement, which largely segregates costs in this manner. Revenue requirement items associated with certain types of plant were generally treated in the same manner as the corresponding plant account.

The specific functions used for FortisBC's COSA are defined below. The functions generally follow standard cost of service approaches.

- ***Power Supply*.** The power supply function includes both rate base and expense items associated with generation owned by the utility and power purchase expenses.

- ***Transmission*.** The transmission function includes those costs for operating and maintaining the transmission lines, poles, towers, substations, etc., used to deliver power to the distribution network's load centres. Transmission is generally those lines measured at 35,000 volts and above.

- ***Distribution*.** Distribution services include all services required to move the electricity from the point of interconnection between the transmission system and the distribution system to the end user of the power. These include substations, poles, primary and secondary poles and conductors, line transformers, services and meters as well as customer costs and any direct assignment items. Customer-related services are also included within the distribution function, even for those customers served at the transmission voltage level. These services include meter reading, billing, collections, advertising, etc. Primary distribution is at voltages of 750 to 35,000 volts while secondary distribution has voltages of 750 volts or less.

The two areas where there generally are differences in functionalization among utilities are in the treatment of general plant and administrative and general (A&G) expenses. Typically, general plant is considered a separate category in the rate base. Functionalization is performed by spreading the general plant rate base across the three other functions. On the expense side, A&G costs are treated in much the same way. Generally, they are treated as a separate expense category that can be spread across the primary functions.

Functionalization of Rate Base

FortisBC has $238.5 million in hydraulic production rate base (accounts 330 to 336). These items are related to the Kootenay River Plants owned by FortisBC. All of these accounts are functionalized to power supply.

FortisBC has $442.8 million in transmission rate base (accounts 350 to 359) which is all functionalized as transmission.

Distribution rate base is the biggest functional component of the FortisBC system and includes $1,010.7 million in rate base (accounts 360 to 373). These costs are all functionalized as distribution.

General plant for FortisBC is $251.2 million and includes computer and office equipment, transportation equipment and other items that are used by employees serving all three functional areas. To split general plant costs into the various functions, labour ratios were used, which is the same as for the 2009 COSA. The labour ratios reflect the number of full-time equivalents assigned to each of the three functions, with a result of 28% generation, 22% transmission and 50% distribution.

Gross plant for FortisBC is $1.94 billion. Accumulated depreciation is equal to $577.3 million, resulting in a net plant amount of $1.37 billion. Accumulated depreciation was further split into production, transmission, distribution and general plant. Each of the accumulated depreciation accounts was treated in the same fashion as the corresponding gross plant accounts.

Working capital for FortisBC was set at $2.9 million, which was added to rate base along with an adjustment for capital additions of $3.0 million. Each of these items was functionalized on the same basis as all O&M costs. Working capital is set aside to cover the time lag between when costs are incurred and when revenue is received from customers. Because O&M and purchased power costs are the primary bills paid by the utility, O&M costs was considered to be a reasonable method for functionalizing and allocating working capital costs. The adjustment for capital additions is similar to working capital was therefore treated in the same manner as working capital.

The rate base was reduced by $112.9 million in customer contributions. All of these contributions were for items at the distribution level and were assigned to functions on the basis of poles, conductors and transformers.

Other rate base items totaled $25.6 million and were separated out by function. The largest item in this category is $12.3 million of related to deferred demand-side management (DSM) spending. This DSM amount was functionalized and classified as 72% power supply energy, 17% power supply demand and 12% transmission and distribution. This split is consistent to that used by FortisBC in the cost/benefit analyses performed for DSM spending.

Functionalization of Revenue Requirement

FortisBC has an approved net revenue requirement from rates of $362.1 million for the 2017 forecast year. This amount, net of $1.4 million of revenues from Rate 37, is used in the COSA. The resulting revenue requirement for COSA purposes is $360.7 million. In allocating the revenue requirements, expense items often follow the treatment of the corresponding rate base item.

Total production/power supply costs are projected at $152.2 million for 2017 and are all functionalized to production. This includes accounts 535 to 556.

FortisBC has $18.3 million in transmission expenses for 2017 (accounts 560 to 567) which are all functionalized as transmission.

Total distribution expenses are projected at $10.4 million for 2017 (accounts 580-598) and are annual expenses associated with the distribution rate base accounts. All of these items are functionalized to distribution.

FortisBC has $6.5 million in customer service expenses (accounts 901 to 910). These costs are all functionalized to the Distribution Function.

A&G costs for FortisBC are forecast at $13 million for 2017 (accounts 920 to 933). Like general plant, these costs are related to all functions of the utility and are often associated with the number of employees of the utility. Labour ratios were used to functionalize these costs to production, transmission and distribution.

Depreciation expenses in account 403 are $55.7 million for 2017 and are split by functional areas. Generation depreciation follows generation plant and likewise treatment for transmission and distribution. Depreciation for general plant and deferred charges follow the gross plant before general plant. DSM amortization follows the DSM rate base account.

Return for 2017 is projected at $87.2 million, with another $10.8 million in income tax. These accounts are all functionalized on the same basis as the total rate base. Property taxes of $16.1 million are related to the value of FortisBC's assets and are therefore treated in the same manner as the total system net plant.

In addition to revenues from retail and wholesale sales to customers, FortisBC receives revenues from other activities, such as pole attachment fees. Because the COSA is concerned with collecting revenues from rates by customer class, the other revenues of the utility are treated as an offset to the revenue requirement. Other revenues are therefore credited back to customer classes in a manner that fits the specific revenue item. Total other revenues for 2017 are projected at $8.1 million.

Another $1.4 million was added to other revenues to reflect the revenues collected under Rate 37. These revenues are new since 2009 and reflect the charges associated with standby power for FortisBC's self-generating customer. Because these charges are for standby power and rates are set less than the full cost of service, the COSA is not an appropriate way to develop the rates or determine whether they are recovering related costs. Because the other customers on the system pay for the facilities used to provide this discounted service, it was decided that the firm customers should all benefit from the associated revenues. Other customers are better off having the standby sales because the alternative would provide no additional revenues. Without the standby service offering, the customer would reduce its service to just the portion taken under Rate 31 and would forgo standby service. The Rate 37 revenues, even at a reduced rate, provide a contribution to the fixed costs on the system, which benefits all customers. These revenues are allocated on the basis of all rate base in consideration of the contribution to all fixed costs of the system.

Electric apparatus rental is primarily for pole attachment and is credited on the basis on the rate base account for poles, towers and fixtures. Waneta and Brilliant contract revenues are credited on the same basis as generation rate base. Connection charges are credited on the basis of retail customers. Sundry revenue and investment income are assigned on the same basis as gross plant before general plant.

Classification of Costs

The second step in performing a COSA is to classify the functionalized expenses to traditional cost-causation categories. These cost-causation categories can be directly related to specific consumption behavior or system configuration measurements such as coincident peak (CP) or non-coincident peak (NCP) demand, energy, or number of customers. Each classification category will have a specific allocator that, when applied, will distribute those costs among the appropriate customer classes during the allocation phase of the analysis.

The three primary classifiers are:

- Demand
- Energy
- Customer

Functionalized power supply costs are generally split between demand and energy. Transmission system costs are generally classified as demand-related. Distribution costs are generally split between demand-related and customer-related components, or directly assigned to a specific customer class of service.

Within the three categories, there are multiple ways of defining each option as well as varying ways to split costs between two or more classifiers. For example, demand- and energy-related costs can be separated by seasonal distinctions as well as to reflect peak/off peak consumption periods. Customer categories can distinguish between actual customer and weighted customer characteristics. Other classifiers sometimes used in the process include revenue-related and direct assignment. In addition, there are many instances where costs are not specifically classified to a particular category but rather in the same manner as an individual cost account or subtotal of specific cost accounts.

Classification of Generation and Transmission Rate Base

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

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

Generation classification can be done using several different methods, most of which rely on looking at the use of various types of plants and their purpose within the system. For a utility with multiple generating plants it is common to look at the function of each plant in serving energy and demand needs, with some plants considered peaking units and others more related to providing energy. Sometimes the capital costs of a plant are considered demand-related and operating costs are considered energy-related, particularly for plants having significant fuel costs. Another approach is a peak credit method where the demand component is based on the cost of building a plant designed primarily to meet peak loads and any additional plant costs are deemed to be energy related. Other times the market based pricing of demand and energy components are used to develop the classification split.

In the case of FortisBC, the Kootenay River Plants are the only utility-owned generation, and costs associated with the plants are a small percent of total power supply costs. This makes it difficult to use many of the standard classification methodologies and the small level of costs involved do not warrant a time-consuming or expensive study of the issue. On the other hand, BC Hydro does have a great deal of utility-owned generation and has had their classification of generation costs reviewed and approved through the regulatory process.

To develop the classification split for FortisBC, the output from the Kootenay River plants was priced as if it were purchased at the BC Hydro 3808 rate to determine the equivalent split in costs between demand and energy. This split was then applied to actual costs of the Kootenay River plants for purposes of classification. The resulting split was roughly 20% demand-related and 80% energy-related. This approach was first used in the 2009 COSA and was accepted by the Commission.

There were several factors considered when electing to use this proxy approach for classifying generation rate base for FortisBC. Despite some issues surrounding the derivation of Rate 3808, it does reflect the price paid by FortisBC for a large part of its power supply. To some extent FortisBC faces the decision to generate with its own hydro plants as opposed to purchasing from BC Hydro under the BC Hydro 3808 rate. And while theBC Hydro 3808 rate may not represent the best classification of costs from BC Hydro, it is what is in place today and is included in the rates of BC Hydro.

There are two issues surrounding Rate 3808. As a result of concerns from the Commission, BC Hydro has been ordered to provide a more thorough analysis of generation plant classification in its next rate application. When this is completed FortisBC will re-examine its own classification method. Also, the pricing of Rate 3808 includes a transmission component. In theory, one would want to separate out just the generation component of Rate 3803 for use by FortisBC. However, in looking at the underlying classification of costs to the transmission class of BC Hydro, the generation split is equivalent to the 80% demand and 20% energy resulting from the full Rate 3808. So, while Rate 3808 may not fully match the results of the BC Hydro COSA, the net result is equivalent to the approach FortisBC would like to achieve for classification.

The transmission rate base includes the utility's own transmission assets associated with providing power to FortisBC's distribution system. In addition, FortisBC purchases wheeling from the BC Hydro in the Okanagan and Creston areas to supplement its own transmission. The cost of providing transmission service to a customer is considered to be directly proportional to the contribution to system peak demand that customer imposes on the system. All transmission rate base accounts are classified 100 percent demand-related, as was the case for the 2009 COSA.

Classification of Distribution Rate Base

Generally, there are two methodologies that can be used to classify distribution costs: 100% demand and minimum system. The 100% demand methodology assumes that the distribution system is built to meet the non-coincident peak (NCP). Therefore, distribution costs are classified as 100% demand-related. The 100% demand approach was rejected as EES believes that the system is built in part to reflect the fact that the customer is hooked up to the system, regardless of load level.

Distribution costs can also be split between demand and customer according to a minimum system approach. This approach reflects 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 concept follows that any costs associated with a system larger than this minimum size are due to the fact that customers “demand” a delivery quantity greater than the minimum unit of electricity and that therefore, those costs should be treated as demand-related. Because the residential class tends to have a higher share of the number of customers as compared to the share of non-coincident peak, the minimum system methodology tends to allocate more costs to the residential customer class and customer charges tend to be higher than with the 100% demand methodology.

The process of cost classification is the area within the COSA that can create considerable cost variability between customer classes due to differences in system configurations, demand measurements and system planning criteria. The complexity of the entire COSA process is further compounded since, in some cases, the classification category is clear but the specific allocator is not. For example, a particular cost item may clearly be peak demand-related but that demand can be measured as either a single coincident peak (1 CP) for the year, a combined winter and summer coincident peak (2 CP) approach to reflect seasonal considerations, the sum of 12 monthly coincident peaks (12 CP), or through some other approach.

Distribution services include all services required to get energy supply from the point of interconnection between the transmission system and the utility’s load centres to the end user of the power. Classifying distribution costs requires a special analysis of the nature of the costs. Most distribution costs are appropriately 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. Different accounts within the distribution function are treated separately. For purposes of the COSA, FortisBC conducted a specialized study termed a “minimum system analysis” which is a theoretical analysis using both engineering and accounting inputs to develop a split of the distribution costs between demand and customer components.

The minimum system 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. FortisBC staff provided the data necessary to complete the minimum system study using current year data. Along with the minimum system results, an offset to account for the peak load carrying capability (PLCC) of a minimum system was incorporated into the analysis. The PLCC adjustment is discussed in the following section. Appendix B contains detailed descriptions of the minimum system and how the resulting splits were calculated, along with the details associated with the PLCC calculation.

The minimum system approach reflects 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 concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers use a delivery quantity greater than the minimum unit up to the level of their peak demand, therefore, that portion of the costs should be treated as demand related.

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

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

Another method called the zero-intercept method was considered as well. It is very similar to the minimum system except that it creates a theoretical size of equipment which would carry zero load on the system. It is created by looking at the relationship between the cost of equipment and the size of the equipment. For example, if the formula for the price of a pole is equal to $100 plus $20 per foot, a 30-foot pole would cost $700 and a 35-foot pole would cost $800. With the zero-intercept method, a zero-foot pole would be set at $100 and would be considered the minimum size. The costs associated with that zero-foot pole would be classified as customer-related. This approach can sometimes lead to unreasonable results as the y-intercept may not always be a positive number. By using the PLCC approach in conjunction with the minimum system, the impacts are similar in theory to the zero-intercept approach.

The minimum system analysis was conducted for the 2009 COSA. For the 2017 FortisBC COSA, the minimum system was updated using 2016 data and reflects differing splits for each distribution line item. Detailed results are found in Appendix B.

The following summarize the resulting classification for the distribution accounts used for the 2017 COSA.

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

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

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

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

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

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

Peak Load Carrying Capability Adjustment (PLCC)

While the minimum system is, in theory, designed to carry only a minimal amount of load, the actual facilities designated as the minimal size are actually capable of carrying some amount of demand, therefore overstating the level of the customer-related component. The actual amount of demand capability within the minimum system is a function of load density, minimum required clearances, minimum equipment standards, temperature, and other engineering considerations. Under traditional cost allocation techniques, each customer/connection attracts an equal allocation of the minimum system, plus each customer class is allocated demand costs based on the total customer class' non-coincident peaks. As such, it has been argued that a customer class' non-coincident demand allocator is too large, because a portion of these peak demand-related costs are being covered through the per customer/connection minimum system allocation.

The correction of the problem of over allocating demand can be achieved by the application of a PLCC adjustment. This adjustment was first introduced in the 2009 COSA. The precise amount of a PLCC adjustment should match the definition of the minimum system adopted. In the FortisBC case, it was determined that the average PLCC for the FortisBC system is 1.09 kW per customer. Appendix B provides a more detailed discussion of the PLCC and how the amount was calculated.

The PLCC adjustment will determine how much demand for a customer class can be met by the minimum system (number of customers/connections x PLCC for minimum system) and will credit this amount against the classification's non-coincident peak demands used for determining demand allocators. The adjusted customer class' non-coincident peaks can then be used to allocate the distribution demand-related costs, eliminating the double-counting. The number of customers/connections used for the PLCC should match the number of customers/connections used to allocate the customer component of the distribution capital and O&M costs associated with poles, conductors and transformers.

Other Rate Base Items

General plant, after being functionalized to the three areas, was classified using the resulting classification as total rate base for each function. For example, the 26% of general plant assigned to generation was split between demand and energy in the same manner as the generation rate base. Accumulated depreciation accounts and working capital accounts were classified in the same fashion as the corresponding gross plant accounts. Customer contributions were assigned to classes on the basis of poles, conductors and transformers.

The $5.87 million of plant acquisition adjustment and deferred costs was classified on the same basis of Gross Plant prior to General Plant. The amounts for *Construction Work in Progress* (CWIP) not earning *Allowance for Funds used during Construction* (AFUDC) assigned to each function was classified in the same manner as the rate base for each function. DSM was classified as 71.6% power supply energy, 16.6% power supply demand and 11.8% transmission and distribution demand. This split is consistent to that used by FortisBC in the cost/benefit analyses performed for DSM spending.

Classification of Production/Power Supply Expenses

Classifying power supply costs to demand and energy components depends on the use of the generation and the pricing for power supply purchases. When a utility has numerous generating facilities the use of the various units to supply baseload versus peaking power should be considered. In the case of FortisBC, the power supply resources include FortisBC-owned generation, long term power purchase contracts including a tariff-based purchase from BC Hydro, and a small amount of market purchases. All of the resources used by FortisBC have both an energy and peaking component to them.

Total peak demand for the FortisBC system is expected at 761 MW in December 2017 with average energy forecast at 406 MWa for the year. Total power supply costs for 2017 include purchased power expenses of $136.2 million and direct costs associated with FortisBC-owned generation of $15.9 million.

FortisBC owns four hydroelectric generating units collectively referred to as the Kootenay River Plants. Output from these plants is governed by a water coordination contract with BC Hydro and other parties on the Kootenay River, which predefines the amount of power that can be used at various times. The O&M expenses associated with the Kootenay River Plants are all classified and allocated on the basis of the generation rate base.

The next resource is a contract for power from the Brilliant hydro plant, owned by the Columbia Power Corporation. Under the contract, FortisBC is allocated a share of the output from the project in exchange for paying a share of the costs of the project. The costs associated with the purchase from the Brilliant plants are based on the actual capital and operating costs of the plant.

FortisBC also has a capacity contract for power from the Waneta Expansion project. In this case the costs are all capacity related. While this is a pure capacity contract, it really serves to support the other purchases made by FortisBC.

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

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

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

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

Table 7
Power Production Cost Detail

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

Because power supply sources vary by month, power supply costs were classified to demand and energy for each month and then allocated to customer classes on the basis of each class' contribution to system peak and energy loads for each month. As discussed above, purchases from BC Hydro already have a demand and energy component. Market purchases and sales also are priced using demand and energy components every month and are therefore classified in that manner.

On a combined basis, the total purchased power expenses were classified 27% demand-related and 73% energy-related on an annual basis.

Classification of Other Expenses

The transmission function includes FortisBC's own transmission assets associated with providing power to FortisBC's distribution system. In addition, FortisBC purchases wheeling services from BC Hydro in the Okanagan and Creston areas to supplement its own transmission. The cost of providing transmission service to a customer is considered to be directly proportional to the demand that customer imposes on the system. All transmission expense accounts are classified on the same basis as transmission rate base.

Many of the distribution expense accounts correspond to a rate base account and follow the treatment of the rate base item. For example, account 583.10 is for distribution line maintenance, corresponding to rate base account 365-conductors and devices. Since the distribution rate base uses a minimum system approach, the expenses will also follow the splits resulting from that analysis. Street lighting expenses are directly assigned to the lighting class. Account 598 – other distribution plant is classified on the basis of total distribution rate base.

Customer Service expenses are all classified as customer-related.

A&G was first assigned to each function on the basis of labour ratios. These amounts were then classified on the same basis as the rate base for each of the three functions. The rate base was used because the employees are more closely tied to the size of the asset value of the three functions as opposed to the O&M associated with each function.

Depreciation expenses assigned to each function follow the rate base for that function. Depreciation for general plant and deferred charges follow the gross plant before general plant. DSM amortization follows the DSM rate base account.

Return accounts are all classified on the same basis as the total rate base. Property taxes of $16.1 million are related to the value of FortisBC's assets and are therefore treated in the same manner as the total system net plant.

In addition to revenues from retail and wholesale sales to customers FortisBC also receives revenues from other activities, such as pole attachment fees. Because the COSA is concerned with collecting revenues from rates by customer class, the other revenues of the utility are treated as an offset to the revenue requirement. Other revenues are therefore credited back to customer classes in a manner that fits the specific revenue item. Total other revenues for 2017 are projected at $9.5 million.

Electric apparatus rental is primarily for pole attachment and is credited on the basis of the rate bases account for poles, towers and fixtures. Lease revenue is treated on the same basis as general plant rate base as it covers revenue from general utility assets rather than from generation assets or utility poles. Waneta and Brilliant contract revenues are credited on the same basis as generation rate base as these revenues offset the costs associated with FortisBC's power supply. Connection charge revenues are credited on the basis of retail customers. Sundry revenue and investment income are more general in nature and are therefore assigned on the same basis as gross plant before general plant.

Allocation of Costs

The third step in performing a COSA is the allocation of the utility's total functionalized and classified revenue requirement to the customer classes of service. This is performed through the application of an appropriate allocation methodology.

For each of the primary classifiers discussed above, distinctions have been made within each category to better reflect cost-causation. The following are the specific allocation methods used in FortisBC's COSA. The specific method of cost classification and allocation for various rate base and expense items is discussed in further detail below.

Demand Allocation Factors

For purposes of this study, three types of demand allocation factors were developed.

- *Non-Coincident Peak Demand Allocation Factor (NCP).* First, a non-coincident peak demand allocation factor was developed for each customer class. Expenses classified and allocated by the non-coincident peak demand allocation factor included those predicated on maximum demands such as distribution substations, and a portion of poles and lines, transformers, meters and services. The NCP demand method allocates costs to each class of service based upon their highest non-coincident peak demand regardless of the time of occurrence. These NCP demand allocators are further separated in NCP at primary (NCPP) and secondary voltages (NCPS). The NCP allocators were used for distribution rate base items, with substations based on NCPP, transformers based on NCPS, and poles and conductors split 80% to NCPP and 20% to NCPS. This split is based on industry experience.

- Given the use of the PLCC adjustment as part of the minimum system treatment of distribution costs, the NCP allocation factors are calculated after subtracting the PLCC amount times the number of customers in each rate class.

- *Monthly Coincident Peaks (CP).* For each class of service, a contribution to the system coincident peak in each month was derived from the non-coincident peak and the use of a coincidence factor. Coincident peaks are used for allocating the demand-related potion of power purchases as they differ in each month based on system usage.

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

Demand Allocation Alternatives

The issue of determining the most appropriate allocation methodology for transmission facilities has been studied by a number of regulatory bodies in North America. Precedents on rate setting matters are valuable as they come as a result of a comprehensive and transparent public proceeding. As an example, in the United States, the Federal Energy Regulatory Commission (FERC) has reviewed and opined on numerous transmission rate setting applications, and provides a good forum for aggregating information on standard industry practice in the areas of costing and pricing of transmission services. FERC also provides a convenient forum for debate of new practices within the electric industry and offers a comprehensive database of regulatory analysis, debate and precedents.

FERC was required by the *Federal Power Act* to establish transmission rates that are just and reasonable, and not unduly discriminatory or preferential. FERC also developed a transmission rate policy that stated transmission rates must "(1) allow the transmitting utility to recover all the costs incurred in connection with the transmission services and necessary associated services including, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities; (2) promote the economically efficient transmission and generation of electricity; (3) be just and reasonable, and not unduly discriminatory or preferential; and (4) ensure, to the extent practicable, that costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the applicant for service and not from a utility's existing wholesale, retail and transmission customers."[2]

In most cases, FERC has accepted one of five coincident peak (CP) methods for classifying and allocating transmission costs: 1 CP, 2 CP, 3 CP, 4 CP or 12 CP. If a utility's monthly system demands are relatively flat (i.e., there is not a large difference between the 12 monthly peaks within a given year), FERC precedent supports the use of a 12 CP allocation. If a utility experiences a "pronounced peak" during less than all 12 months, FERC precedent supports the use of other CP methods. FERC has established four tests to determine whether or not a utility has a "pronounced peak". These tests help determine if the transmission system was sized based on a peak occurring only a few times each year or if the transmission system was used more evenly during all 12 months of a year.

These tests are:

<u>FERC Test #1</u>

The first test compares the average of the system peaks during the purported peak months as a percentage of the annual peak to the average of the system peaks during the off-peak months as a percentage of the annual peak.

FERC Test #1 = (Average Monthly Peak during Peak Months ÷ Annual Peak) – (Average Monthly Peak during Off-Peak Months ÷ Annual Peak)

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

[2] Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, Notice of technical conference and request for comments, 58 Fed. Reg. 36,400 (July 7, 1993).

FERC Test #2

The second test calculates the lowest monthly peak as a percentage of the annual peak.
FERC Test #2 = Lowest Monthly Peak ÷ Annual Peak

Greater percentages support using 12 CP. Historically, FERC has supported using 12 CP when the percentage is greater than 65%.

FERC Test #3

A third FERC test looks at the extent to which peak demands in non-peak months exceed the peak demands in the alleged peak months. FERC precedents show that if the peaks in what are considered to be non-peak months frequently exceed the peaks in alleged peak months, the 12 CP methodology is adopted. If it is fairly uncommon for the peak demand in a non-peak month to exceed the peak demand in a peak month, then an allocation other than 12 CP has historically been adopted.

FERC Test #4

A fourth test calculates the average of the twelve monthly peaks as a percentage of the greatest monthly peak.

FERC Test #4 = Average of 12 Monthly Peaks ÷ Annual Peak

A greater percentage supports using the 12 CP methodology. Based on precedent, a result of 81% or greater, supports using 12 CP.

The Ontario Energy Board (OEB) has also explored the issue of an appropriate classifier and demand allocation factor for transmission facilities in the recent cost allocation review undertaken for the Ontario Local Distribution Companies (LDCs). As part of this review, two tests were developed by the OEB to determine the appropriate classification and allocation procedure for transmission facilities. These two tests are summarized below.

OEB Test #1

The first OEB test calculates the average of the twelve monthly system peaks as a percentage of the highest monthly system peak. A Test #1 result of 83% or greater indicates that 12 CP should be used. If the Test #1 result is less than 83%, then Test #2 must be conducted to determine if a 1 CP or a 4 CP is to be used.

OEB Test #2

The second OEB test calculates the average of the four highest monthly peaks as a percentage of the highest monthly system peak. Note, that contrary to the FERC tests which require that consecutive monthly peaks are used, the OEB Test #2 utilizes any four highest peaks. A Test #2 result of 83% or greater then the distributor must use 4 CP as the allocator, while a 1 CP should be used if the Test #2 result is less than 83%.

The FERC and OEB tests were developed based on comprehensive analyses of utilities in North America, and EES considers the tests to be appropriate methods of determining the appropriate allocator for FortisBC.

Selection of 2 CP Method

In selecting the appropriate peak demand allocator for production and transmission, the FERC and the OEB tests were examined along with looking at the overall shape of the peaks, and at the growth rates for winter and summer peaks. The various tests were calculated for several years as well as for the 2017 forecast used in the COSA. The results are provided in Table 8.

Table 8
FERC and OEB Tests for Demand Allocator

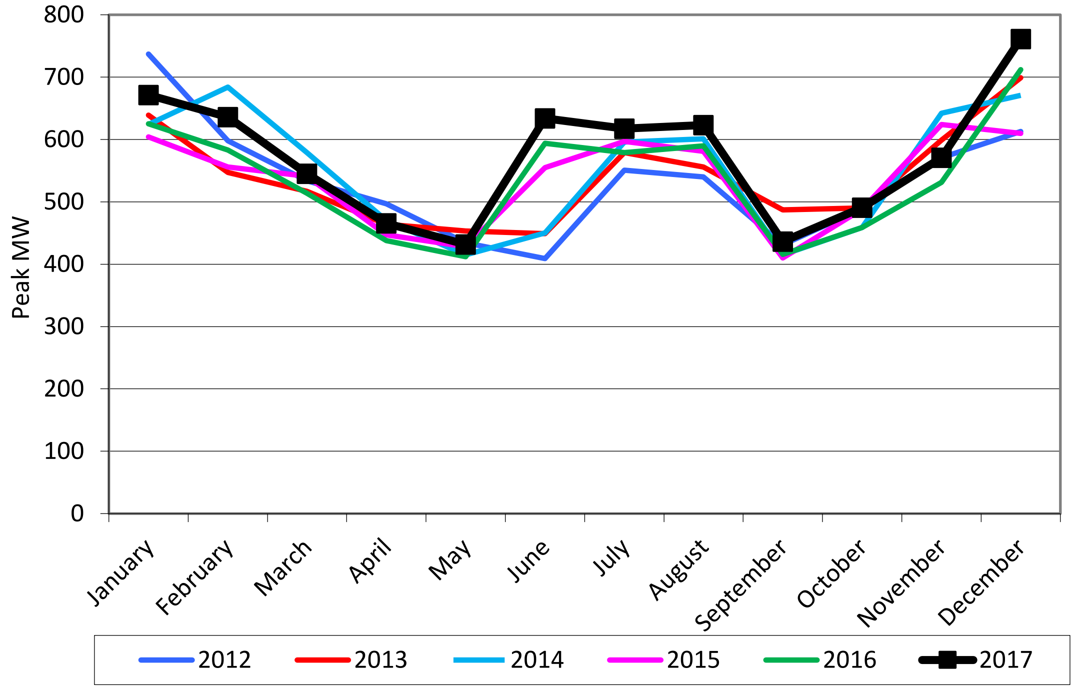
Test	C2012	C2013	C2014	C2015	C2016	C2017 Forecast
FERC Tests						
#1	12CP	12 CP	1CP or 4CP	12CP	12 CP	12CP
#2	1CP or 4CP	1CP or 4CP	1CP or 4CP	12 CP	1CP or 4CP	1CP or 4CP
#3	Does not exceed (1CP or 4CP)	Does not exceed (1CP or 4CP)	Does not exceed (1CP or 4CP)	Does not exceed (1CP or 4CP)	Does not exceed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

The results generally support the use of a 1 CP or 4 CP approach, however, it is important to note that the tests only consider a 1 CP, 4 CP or 12 CP method and have left out the use of a 2 CP method. In most years the 12 CP shows up under FERC Test #1, however, the results are very borderline. None of the other tests result in a recommended 12 CP method other than in 2015.

As the FERC and OEB tests do not specifically contemplate a mixed winter/summer peak, the tests do not rule out the use of that approach. What is important to note from the results is that the FortisBC system is more seasonal than it is flat throughout the year, eliminating the use of the 12CP method.

The next consideration was to graphically examine the load shape for FortisBC to help in understanding the particular circumstances of the specific utility. Figure 1 shows the overall shape for the 2017 test year as well as previous years. It is very clear from the table that there is a prominent peak in the summer months.

Figure 1
FortisBC Monthly Peaks



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

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

Energy Allocation Factors

Energy costs vary directly with consumption. Accordingly, energy allocation factors were based upon electricity sales for each class. For purposes of monthly power supply costs, the energy in each month was used as the allocator.

Customer Allocation Factors

Two basic types of customer costs were identified—actual and weighted.

- *Actual Customers (CUST).* The allocation factor for actual customers was derived from the actual number of customers served in each class of service averaged across the 12 months of the 2017 test period. Note that for wholesale customers the number of points of delivery (POD) were included in some cases as each POD contains its own meter.

- *Customers Weighted for Meters and Services (CUSTM).* The first weighted customer allocation factor considered the relative differences among the various customer classes of meter costs. The typical cost of a new meter for each rate class was used as the weighting factor for each class.

- *Customers Weighted for Accounting/Metering (CUSTW).* The second weighted customer allocation factor considered the cost of customer accounting and meter reading by each rate class. The weighting factors for CUSTW were developed via an allocation of cost performed by FortisBC staff. Once costs were allocated to each class, they were divided by the number of customers and then scaled back so that a weighting factor of 1.0 was used for the residential class and general service customers, 1.4 for lighting and irrigation customers, 159.7 for wholesale customers and 202.5 for industrial customers.

Other Allocation Factors

Other costs are allocated based on specific rate base items, O&M function totals, revenues, labour ratios and other allocation factors.

Allocation of Rate Base

For generation, the 20% demand-related component was then allocated across classes using the 2 CP factor. The remaining 80% energy-related component was allocated on the basis of annual energy by class.

All transmission rate base accounts are allocated on the basis of the 2 CP methodology.

For the 100% demand-related components of distribution, the NCPP is used as the allocation factor. For those distribution accounts split between demand and customer components, the NCPP, NCPS and actual number of customers are used. Those distribution accounts that are

100% customer-related are allocated on the basis of customers weighted according to the average cost of meters by class. Street Lights & Signal Systems all directly related to the lighting class of customers and are directly assigned to that class.

General plant costs were allocated to classes on the same basis as was used for each of the classified components.

Each of the accumulated depreciation accounts was allocated in the same fashion as the corresponding gross plant accounts. Working capital items were allocated on the same basis as all O&M costs. Customer contributions were assigned to classes on the same basis as poles, conductors and transformers.

Allocation of Revenue Requirements

Because power supply purchases vary by month, power supply costs were classified to demand and energy for each month and then allocated to customer classes on the basis of the class contribution to system peak and energy loads for each month.

All transmission expense accounts are allocated on the same basis as transmission rate base, which is based on 2 CP.

Distribution expense accounts generally correspond to a rate base account and follow allocation of the rate base item. Street lighting expenses are directly assigned to the lighting class. Account 598 – other distribution plant is allocated on the basis of total distribution rate base.

For customer service expenses, each account is considered separately for allocation. Supervision and administration expenses follow all other customer service expenses. Meter reading, customer billing and customer assistance are allocated on customers weighting for accounting/metering. Credit and collections expense are allocated to retail customer only.

A&G costs were functionalized using labour ratios and then classified and allocated on the same basis as the rate base for each of the three functions. This follows the same treatment described for general plant.

Depreciation expenses follow the allocation treatment used by the associated functional accounts. Depreciation for general plant and deferred charges follow the gross plant before general plant. DSM amortization follows the DSM rate base account.

Return accounts, (interest, earnings, and income taxes) are all allocated on the same basis as the total rate base. Property taxes are related to the value of FortisBC’s assets and are therefore allocated in the same manner as the total system net plant. Net plant reflects the gross plant for the utility less accumulated depreciation.

FortisBC receives revenues from retail and wholesale sales to customers, as well as for other activities, such as pole attachment fees. Because the COSA is concerned with collecting revenues from rates by customer class, the other revenues of the utility are treated as an offset to the revenue requirement. Other revenues are therefore credited back to customer classes in a manner that fits the specific revenue item.

Other Cost Calculations

Aside from the typical cost allocations by customer classes, some additional analyses were conducted to assist in develop certain rates components. In some cases these were based on the data within the COSA and in other cases it reflects data outside of the COSA. The areas that require additional analysis include TOU rates, a discount for wholesale service at transmission voltage, the line extension credit and wholesale transmission rates. Each of those areas is discussed in further detail below.

TOU Cost Differentials

FBC currently offers TOU rates for certain rate classes. Rate 2A is the residential TOU rate and it is currently closed to new customers. FBC intends on re-opening this rate schedule as an optional rate available for all residential customers. Rates 22A, 23A, 32 and 33 are TOU rates for various commercial classes and all remain open as optional rate schedules provided the customer has a satisfactory load factor. In 2016 there were roughly 1400 residential TOU customers, roughly 20 customers on Rate 22A and one customer on Rate 32. These customers were not used as separate rate classes in the COSA because the COSA does not differentiate costs by time period. Instead they were all included with their corresponding non-TOU rate classes.

Because the COSA does not provide the cost data necessary to look at various TOU periods, EES looked outside the COSA to develop the proposed TOU rates. The first step was to examine the TOU periods and the second step was to look at the cost differences by time period.

Appropriate TOU periods were developed by looking at the total system loads by hour for the past 5 years to group periods with similar load levels into TOU periods. The December/January period was looked at in detail as was the July/August time period. The current TOU periods contained only an on-peak and off-peak period. Most current TOU rates for other utilities contain an on-peak, mid-peak and off-peak period because that better represents the cost differentials between periods. This is something that has evolved over time with other utilities, with many other utilities originally using just two time periods. This is an issue across months as well as within a day. While the winter months and summer months both have high usage and high costs in peak hours, loads and costs are lower in the shoulder months. The same is true within days where loads and costs are highest in the morning and at dinner time.

There is no clear cut off where loads change from one level to another as changes throughout the day and across months are gradual. There are also some days where loads are higher within a given month because of weather conditions. The goal in developing the TOU periods was to capture the periods that consistently have higher usage levels while at the same time are easy to understand for customers and will not result in shifting the peak period for the utility. Loads in each hour were compared to the average load for the day and if they were 90%

or more of the daily peak those hours were generally considered on-peak hours. Mid-peak hours generally reflected hours when loads were between 85% and 90% of the daily peak.

On-peak periods were designed to occur only in those months that were used to develop the peak allocations in the COSA. The COSA method uses the two highest winter peaks, which could occur in December, January or February, and the two highest summer peaks which occur in July and August. The load analysis confirmed this as the loads for the shoulder months of March through June and August through November were not as high and warranted the use of just the mid-peak period.

The current TOU rates have a July/August on-peak period weekdays from 9am to 11am and 3pm to 11pm. The load analysis showed that loads are highest in the afternoon hours and so the proposed on-peak period was set from 12pm to 9 pm. The proposed mid-peak period was set as 7am to 12pm. That leaves the off-peak period as 9pm to 7am weekdays.

It is proposed that weekends would be included in the off-peak period as they are now. The weekend daytime hours are typically much less than for weekdays but often higher than the overnight hours included in the off-peak period. Typically, Saturday loads are 92% of weekday loads and Sunday loads are 81% of weekday loads. While including weekend days in the three different periods was considered as an alternative, it was determined that they should be treated the same as under the current TOU periods.

The current TOU periods for all other months have an on-peak period of 8am to 1pm and 5pm to 10pm. The hourly analysis showed that loads in the December through February period are higher than the summer months and should include both an on-peak and mid-peak period. The proposed winter on-peak period is 7am to 12pm and 4pm to 9pm and the proposed mid-peak period is 12pm to 4pm. For the shoulder months, the loads did not rise as much and so the daytime hours were all considered mid-peak. As with the summer period, the off-peak period is proposed to be 9pm to 7 am and all day on weekends.

Table 9 shows the proposed TOU time periods.

Table 9
Proposed TOU Periods

	Dec-Feb	Mar-June	July-Aug	Sept-Nov
On-Peak	7 am to 12 pm and 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	7 am to 9 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	9 pm to 7 am weekdays and all-day weekends and Holidays

Based on these time periods the distribution of residential loads into the time periods were developed. This was calculated based on a sample of residential load data. Table 10 shows the split by time period in terms of the number of hours, percent of load, and average load.

Table 10
Breakdown of TOU Periods

	% of Hours	% of System Load	2016 Average System Load (MWa)
On-Peak	11.4%	14.9%	496.8
Mid-Peak	28.6%	30.7%	406.1
Off-Peak	60.0%	54.4%	344.2

The next step in developing the TOU rates was to look at the cost differentials between the TOU periods. For the distribution system the number of customers and the non-coincident peak of each was used to plan for facilities and this was reflected in the COSA allocations for distribution costs. Costs associated with the transmission and distribution system, while driven by peaks, are not differentiated by time period.

Costs for power supply do, however, differ by time period. FBC has a combination of owned resources, contracted resources, wholesale purchases from BC Hydro, and market purchases for short-term needs. FBC staff split power supply costs for 2016 into several different categories to cover capacity-related costs, energy purchases and baseload costs. The variable capacity costs included the capacity charges related to purchased power and would apply only to the on-peak period. While peak demand is measured by the highest load in any given hour, that peak demand could occur anytime within the on-peak period depending on weather conditions.

The variable energy costs included the energy charges from power purchases from BC Hydro and the market and apply to both the on-peak and mid-peak period. These purchases reflect purchases on top of the owned generation and contractual resources like Brilliant. These purchases are made in periods that are higher than the base load that is covered by owned and contractual resources, but lower than the peak periods. All other power costs would be considered base costs that would apply to all TOU periods.

By splitting out these costs and then dividing by the appropriate loads in the various TOU periods, a differential of 10.6 cents per kWh based on the variable energy cost was calculated for the ond-peak period in comparison to the mid-peak period. A differential of 2.6 cents per kWh based on the variable energy purchase cost was calculated for the mid-peak period in comparison to the off-peak period.

For each specific customer class, the usage by TOU rate period was determined using AMI hourly data. Table 11 summarizes the percent use in each TOU period in total and for each class.

Table 11 Percent Use in Each TOU Period			
Rate Class	On-Peak Use	Mid-Peak Use	Off-Peak Use
Residential	15.8%	28.5%	55.8%
Small Commercial	14.3%	34.1%	53.6%
Commercial	14.4%	34.1%	51.5%
Large Commercial	14.0%	33.5%	52.5%
Wholesale Primary	12.4%	32.3%	55.4%
Wholesale Transmission	12.4%	33.8%	53.8%
Total System	14.9%	30.7%	54.4%

The adders were then used to develop proposed TOU rate differentials. Using the adders, the off-peak rate was set so that the total revenues collected would be revenue neutral with the proposed non-TOU rates.

A final adjustment was made to account for the impacts in usage associated with TOU rates. An elasticity factor was applied to the load in each time period. Based on the 2014 RIB analysis we found an elasticity of -0.14 for block 2 and applied that to the on-peak period. The elasticity for the block 1 use was -0.07 (although not statistically significant) and that was applied to the mid-peak and off-peak periods. Note that for the irrigation class the elasticity of 0-.14 was used for both all time periods as the total amount of water use is likely to remain unchanged. Elasticity was applied to the usage levels and comparing the TOU rates in each period to the average energy rate. The result was a decrease in the on-peak period and on an overall basis. This in turn led to rates that needed to be slightly higher to accommodate the loss in revenues. Additionally, the reduced power supply cost associated with overall reduced consumption was applied as an offset to the revenue when looking at revenue neutrality. The savings was based on the variable energy rate of $0.04863 per kWh from the BC Hydro contract.

Table 12 shows the unit costs for the various TOU periods for each rate class.

Table 12 Unit Costs of Various TOU Periods for Each Rate Class			
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 Primary	$0.18395	$0.07829	$0.05240
Wholesale Primary	$0.19995	$0.09429	$0.06840
Wholesale Transmission	$0.19185	$0.08619	$0.06030

Specific TOU rate proposals were developed by FBC and are included in the application.

Wholesale Discount

Currently, FortisBC has two different rate schedules for wholesale customers. Four wholesale customers are served under Wholesale Service - Primary (Rate 40) and one customer is served under Wholesale Service - Transmission (Rate 41). Currently Rate 41 is only available to the City of Nelson and the rate reflects the fact that the power provided by FortisBC is supplementary to the power generated by the City of Nelson.

Rate 40 customers have expressed interest in taking service at transmission voltage rather than primary voltage. Because Rate 41 would not apply to a full-service wholesale customer, it would not be available to the five Rate 40 wholesale customers. For that reason, FortisBC requested the calculation of a discount for Rate 40 customers taking service at transmission voltage. Because there are no customers or sales in that category, it was not possible to create a separate class in the COSA to develop an applicable rate. However, the COSA is set up to differentiate classes based on the voltage level for service.

To determine the appropriate discount for transmission service, the COSA was changed to reflect all Rate 40 customers as taking service at transmission rather than primary voltage. This change would reduce the allocated revenue requirement for the class from $44.2 million to $36.1 million. This is an 18.4% reduction in the revenue requirement and a 15.9% reduction compared to current rates.

In terms of discounts to the actual rate components, it was assumed that the customer charge of $2,645.03 and the power supply charge of $4.82 per kVA would remain as is. The discount would only be applied to the wires charge and the energy rate. The resulting discount to meet the COSA costs at transmission voltage would be $2.640 for the wires charge per kVA and $0.0077 for the energy charge per kWh.

Because no wholesale customer has opted for this rate at this time there are no impacts on any other rates associated with this proposed discount. If one or more wholesale customers does opt for this rate in the future, the corresponding reduction in revenues will factor into the future forecast revenues and any future rate increases for the utility.

Line Extension Credit

To develop the line extension credits available to new customers connecting to the system, the same approach used in the 2009 COSA was used. This capital credit or allowance is predicated on the amount of investment in distribution poles, conductors, and transformers for each rate class covered in the applicable retail rate. Any investment in poles, conductors and transformers needed to provide service to a new customer in excess of this credit or allowance would be paid for upfront as a capital contribution by the new customer.

The higher principles for distribution system extension charges (extension charges) are that they should be fair to all and collect enough from a new customer to hold harmless all other customers from the incremental costs of supplying new localized distribution poles, conductors and transformers. (Note—the additional costs of meters and services are covered off in the connection charge. The incremental costs of generation, transmission and distribution substations are typically dealt with separately.) The mechanics for calculating an extension charge given these higher principles is to determine how much capital for distribution poles, conductors and transformers is covered by the standard retail tariff (the capital allowance or credit), then charge a new customer the actual cost of new poles, conductors and transformers needed to provide service less the capital allowance or credit. For example, if a new customer requires $3,000 worth of new poles, conductors and transformers and the capital allowance or credit is $1,000, the new customer would pay $2,000 in the way of a capital contribution. This capital allowance or credit methodology is simple to calculate, can be updated each time a COS is performed and holds existing customers harmless from the incremental cost of growth in pole, wire and transformer costs.

The COSA was used as the basis to calculate the line extension credit for each class of FortisBC customers. The rate base associated with distribution account 360 through 364 were summed for each rate class. Accumulated depreciation and CIAC corresponding with the distribution accounts were then subtracted to provide the net distribution investment for the class. This net amount was divided by the number of customers in the class or the non-coincident kW for the class to determine the appropriate level of credit.

Table 13 summarizes the resulting amounts for the line extension credit.

Table 13
Line Extension Credits

Customer Class	Line Extension Credit Amount Average per Customer	Line Extension Credit Amount Average per kW
Residential	$2,634	$344
Commercial	$4,705	$279
Large Commercial	$191,043	$121
Lighting	$2,266	$642
Irrigation	$3,543	$265

The method approved for FortisBC differs from the method approved for BC Hydro, where the present value of the expected distribution demand-related costs is used. Calculating credits based upon a long-range forecast of costs requires numerous assumptions and has the potential for forecast error. The method in use by FortisBC achieves the desired goal of holding existing customer harmless from the addition of new customers, while providing a stable and predictable line extension credit and should continue

Wholesale Transmission Rates

Wholesale transmission tariffs were not re-examined in 2009. At the time, the wholesale transmission tariffs were first developed, they were set as retail wheeling rates for customers that could potentially acquire their power supply from an alternate source and use FortisBC for transmission and distribution delivery service. Therefore, they were basically the full retail rate less the power supply component. To date no customer has used the tariffs in that manner.

In re-examining the appropriate method for setting transmission tariffs for FortisBC, the standard OATT approach was determined to be the best to develop service for entities that wanted to use FortisBC to wheel generated power out of the FortisBC service area.

An OATT typically includes network and point-to-point (PTP) transmission service as well as ancillary services.

Network Rates

For network service, the rate is typically the transmission revenue requirement each month divided by the customer's share of the load that month. Based on the COSA, the transmission revenue requirement for 2017 is $64.3 million per year or $5.36 million per month. This number would need to be adjusted to exclude generation-integration facilities, as described below. Customers with network service pay based on their load each month and the service is not limited to a contractually defined level.

Point-to-Point (PTP) Rates

PTP rates are based on the average cost per kW-month and is based on a contract demand. Customers must designate the level of contract demand they wish to purchase and pay for that contract demand each month, regardless of actual use. Based on the COSA, the average unit cost for transmission is $4.67 per kW-month. However, the costs that are functionalized as transmission in the COSA may not truly reflect the facilities that would be used for PTP service.

While the transmission function in the COSA includes all facilities in the standard FERC transmission accounts, some of the facilities included are actually related to generation-integration and would not be necessary for PTP service. FortisBC staff looked at specific facilities identified as generation–integration and split those out from transmission. For substations, $21.3 million (13.7 percent) was generation-integration. For conductors, $5.5 million (6.8 percent) was identified as generation-integration. We assumed this same percent would apply to poles, resulting in $5.5 million as generation-integration. An average portion of other facilities were also excluded. The net result is that a total of $33.1 million or 10.2 percent of all transmission rate base is related to generation-integration and should be excluded from PTP rates.

The expense items functionalized as transmission, including O&M, return, depreciation and taxes all follow the classification and allocation of the related transmission rate base. For that reason, it is appropriate to reduce the transmission related expenses by the same 10.2 percent.

Based on the $4.67 per kW-month unit cost for transmission resulting from the COSA, a reduction of 10.2 percent would result in a PTP charge of $4.20 per kW-month. The charge would be $0.9692 on a weekly basis and $0.1381 on a daily basis.

For service at distribution voltage, the full amount would be based on the unit cost of the demand-related distribution costs, or $3.87 per kW-month. This would be in addition to the transmission charges.

Ancillary Services

In addition to the network and PTP wheeling rates, there are several ancillary service products offered by FortisBC. In most cases there is not a clear cost basis for charges like there is within the COSA. In a few cases costs can be developed but in other cases it is appropriate to use what other utilities use. In this case BC Hydro is the comparison utility.

Schedule 103 – Scheduling, System Control and Dispatch Service

The current rate is $0.00126 per kWh for transmission voltage and $0.00132 per kWh for primary voltage. BC Hydro's rate is $0.099 per MW of reserved capacity per hour. The costs associated with this service can be taken directly from the COSA. The costs are $2.298 million. Based on NCP demand this would result in a rate of $0.1669 per kW per month, $0.0385 per kW per week, $0.0077 per kW per day and $0.00031 per kW per hour.

If you wanted to be consistent with BC Hydros's format as well as what is proposed for other services, the rate would be $0.32 per MW of reserved capacity per hour.

Schedule 104 – Reactive Supply and Voltage Control

The current rate is $0.00141 per kWh for wholesale transmission and $0.00132 for wholesale primary and large commercial transmission. The BC Hydro rate is $0.825 per MW of reserved capacity per hour.

In this case it is recommended that the BC Hydro rate be used. The underlying generation costs for FortisBC are tied in part to the wholesale power cost from BC Hydro. That would result in a rate of $0.825 per MW of reserved capacity per hour. This is different than a per MWh rate because it would use the reserved capacity in all hours rather than the actual usage.

Schedule 105 – Regulation and Frequency Response

The current rate is $13.62 per MWh of generating capacity requested, which must be a minimum of 2% of load. BC Hydro's rate is $6.37 per MW per hour with the same 2% minimum.

If you were to take the average cost of FortisBC's own generation (capacity portion only) per kW it would result in a comparable charge of $9.31 per MW per hour. That would be applied to a minimum of 2% of the transmission load.

Schedule 106 – Energy Imbalance

The current rate uses a 1.5% hourly balance limit. For positive balances the credit is \$0.05043/kWh for wholesale transmission, \$0.048/kWh for wholesale primary and \$0.04798/kWh for large commercial transmission. Negative balances are charged at the actual cost to the Company plus 10%. The BC Hydro rate uses a 4 MW per hour balance limit and applies a BC Hydro buy price (mid-C less BPA wheeling) with certain factors to go from the mid-C off-peak rate to an hourly rate.

The proposal for FortisBC is to use the 4 MW balance limit along with actual hourly costs for FortisBC. Costs asslocated with wheeling would be subtracted.

Schedule 107 and 108– Operating or Spinning Reserves

The current FortisBC rate is \$13.62 per MWh of generating capacity requested, with a minimum of 2.5% or 3.5%. This is the same rate as Schedule 105. BC Hydro's rate is \$6.20 per MWh, which is close to their regulation and frequency response rate.

The proposed rate should be the same \$0.0825 per MW per hour used for Schedule 105.

Jurisdictional Review of Rates

As with the review of COSA methodologies used in other jurisdictions, EES reviewed the rates in place for other large electric utilities across Canada and the Pacific Northwest U.S. Rates were reviewed in terms of customer classes used, the structure of the rates, and the level of the customer charge. While the level of rates is interesting, all utilities face different costs and include different items in their delivery charges. For that reason, the level of the rates was not a focus of the review.

In general, there was greater consistency in COSA methods than there was in the actual customer segmentation of rate classes and rate design. More utilities were reviewed in terms of rate design than COSA methodology as utilities with different forms or unpublished COSA results did not need to be excluded. The following utilities were included in the jurisdictional electric rate design review:

Canadian Utilities

- SaskPower (Saskatchewan)
- Manitoba Hydro (Manitoba)
- Hydro Quebec (Quebec)
- Nova Scotia Power (Nova Scotia)
- Newfoundland Power
- New Brunswick Power
- ATCO Electric Yukon
- BC Hydro
- ATCO Electric Alberta
- Fortis Alberta

Tables showing the comparison of rates can be found in Appendix D.

Rate Class Segmentation

The first thing to note in the review is that there is a wide range of segmentation of customer classes between the various utilities. The rates for the utilities were looked at in terms of residential, small commercial or small general service, medium commercial or large general service, irrigation or agriculture, and industrial and/or primary service. Below lists the overall survey categories and relative capacity characteristics of each division. If breakpoints between classes were inconsistent, we used the rate class that fell within the rate survey categories. In some cases, this meant that one rate class covered several categories or multiple rates occurred within segmentation categories.

Rate Class Survey Categories

- Residential/Domestic Service
- Small Commercial (less than 40 kW)
- Commercial/General Service (40 kW but less than 500 kW)
- Industrial Service (500 kVA+)
- Irrigation Service

While all utilities had some form of service for residential customers, several utilities offered optional Time-of-Use rates to residential customers and in California some utilities only offered Time-of-Use rates for many customer classes. There the public utilities commission has approved default Time-of-Use rates for most customer classes and especially net metering customers.

In some cases, there was no distinction between residential and other small or general service users. Although some utilities also charged separate general service rates for a shop or garage separately metered, such as Fortis Alberta.

For commercial customers, there were several cases where small and large commercial customers were broken out into two classes, but also cases where one broad commercial or general service class applied. In general, it is more typical for utilities to create a small general service or small commercial rate class than design one block rate to accommodate all levels of usage and load profiles over a broader rate class. Most broad commercial classes were accommodated with a declining block structure to allow for lower rates for larger commercial customers without the need for different customer classes. In Canada, flat rates for Small Commercial are common, but most commercial classes have declining block rates and demand charges.

Large Commerical/Industrial rates varied quite a bit in terms of offerings. In some cases, there was a distinction by size based on maximum kW or kVA, common break-points include 500 kW, 1000 kW, 2000 kW, and 5000 kW, such that there is separate treatment for moderate, large and very large volume service. It is common for special contract requirements for larger customers. Flat energy rates are common with higher kW or kVA charges.

Rate Structure

The rate structure of a utility includes such things as whether there are flat or block rates and whether a demand charge is included.

Flat rates for residential service continue to be common and in are in place at seven of the ten utilities in the comparison.

Table 14 Comparison of Residential Rate Structures		
Utility	**Rate Structure**	**Additional Info**
BC Hydro	Inclining Block	Block 2 >1350 kWh
Fortis Alberta	Flat	
ATCO Electric Alberta	Flat	
ATCO Electric Yukon	Inclining Block	Block 2 1001-2500 kWh Block 3 >2500 kWh
SaskPower	Flat	
Manitoba Hydro	Flat	
Hydro Quebec	Inclining Block	Block 2 over 30 kWh/day
Nova Scotia Power	Flat	
Newfoundland Power	Flat	
New Brunswick Power	Flat	

Rates are typically flat or declining block for commercial classes, with some exceptions where inclining block rates were used.
Note that the declining block rates in many of the cases are used to differentiate large and small users rather than having more rate classes.

Most utilities use demand charges for large commercial/industrial rates. All utilities reviewed have demand charges for large commercial/industrial customers.

Customer Charge

The final comparison includes the level of the customer charge in place at the various utilities. While some charges were applied daily while others were applied monthly, all customer charges were converted to a monthly basis to allow a more applicable comparison.

For residential customers in Canada, the customer charge ranged from $5.78 per month for BC Hydro to a high of $38.59 for ATCO Electric Alberta. See Table 15 below for a comparison of residential customer charges.

FortisBC's residential customer charge is approximately at the mid-point among the utilities included in the comparison. In our experience, the trend is towards higher customer charges to recover the customer-related fixed costs of the system. In most cases the customer charge is significantly less than the full customer-related costs resulting from a utility's COSA. That is the case for FortisBC.

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

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

Large Commercial/Industrial fixed charges for Canadian utilities tended be contractual or based on minimum demand charge amounts. Because the eligibility and terms associated with the various types of industrial rates vary considerably, it is not surprising that the customer charge varies so much.

Summary and Conclusions

Given the above assumptions regarding the COSA, the various costs were classified and allocated to the customer classes of service. This section provides the results of the COSA in summary form. Detailed tables reflecting all of the COSA details can be found in Appendix A.

Rate Base

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

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

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

Revenue Requirement

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

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

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

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

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

Revenue to Cost Ratios

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

Table 16
COSA Revenue to Cost Ratios

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

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

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

Unit Costs

The unit costs per customer class resulting from the COSA are provided in Schedule 2.1 of Appendix A. These costs are useful in comparing the costs between classes as they are provided on a level basis. In summary, unit costs are as follows:

	Cents per kWh
Residential	13.90
Other Retail	9.10
Wholesale	8.58
Total System	10.99

Unit costs can also be used in setting rates that send the appropriate price signals to customers. As the wholesale customers are billed for customer charges on the basis of the number of PODs served, the unit cost for them reflects the costs on a per POD basis. For those customers that do not have demand meters, and therefore no demand charge, all of the demand-related costs have been rolled into the energy cost per unit.

Unit cost calculations were a consideration in adjusting rate design components for the accompanying rate design proposed in this application.

Comparison to 2009 COSA Methodology and Results

Over the past 8 years there have been changes in loads, rate base and expenses. The methodologies used in the COSA, however, were not changed from the 2009 COSA. One added element that was required is related to the revenues from standby power in Rate 37. Because that rate did not exist in 2009 the treatment had to be developed for this COSA.

Standby revenues of $1.4 million were added to other revenues to reflect the revenues collected under Rate 37. Because these charges are for standby power and rates are set less than the full cost of service, the COSA is not an appropriate way to develop the rates or determine whether they are recovering related costs. Because the other customers on the system pay for the facilities used to provide this discounted service, it was determined that the firm customers should all benefit from the associated revenues. Other customers are better off having the standby sales because even at a reduced rate, they are contributing to a share of the fixed costs on the system. These revenues are treated on the basis of all rate base to reflect the contribution to all fixed costs on the system.

As a result of the 2009 rate design application, FortisBC rebalanced various customer classes over a multi-year period to achieve RC ratios in the appropriate range. As a result of that rebalancing, the current RC ratios are primarily with the range or reasonableness.

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

Conclusions

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

Appendix A – COSA Schedules

Fortis BC 2017 COSA

COST OF SERVICE SUMMARY
BY CUSTOMER CLASS
Schedule 1.1

Forecast Year: 2017	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Revenues:												
Customer Charge Revenues	$30,078,526	$22,256,661	$3,248,976	$308,687	$521,662	$149,569	$2,873,518	$266,873	$380,884	$71,694	$22,223,761	$32,900
Energy Revenues	$294,039,904	$162,871,755	$31,025,781	$43,295,404	$17,331,308	$5,294,045		$3,031,918	$27,524,962	$3,664,730	$162,524,623	$347,132
Demand Revenues	$36,423,911			$9,359,664	$7,902,570	$1,648,008			$14,858,633	$2,655,036		
Total Revenues at Existing Rates	**$360,542,341**	**$185,128,417**	**$34,274,757**	**$52,963,756**	**$25,755,540**	**$7,091,623**	**$2,873,518**	**$3,298,792**	**$42,764,479**	**$6,391,460**	**$184,748,384**	**$380,033**
Production-Related Costs	$179,882,785	$78,727,594	$16,539,590	$30,963,845	$15,527,752	$4,775,859	$679,267	$1,835,530	$26,429,297	$4,404,052	$78,565,851	$161,736
Transmission-Related Costs	$64,310,485	$32,373,934	$5,217,272	$9,107,704	$4,401,167	$1,571,387	$70,650	$400,331	$9,509,926	$1,658,114	$32,295,918	$78,004
Distribution-Related Costs	$116,485,630	$77,113,861	$11,798,550	$10,520,536	$4,854,445	$280,205	$2,366,517	$1,160,605	$8,299,182	$91,729	$76,958,968	$166,066
Total Allocated Revenue Requirements	**$360,678,900**	**$188,215,388**	**$33,555,412**	**$50,592,085**	**$24,783,364**	**$6,627,451**	**$3,116,434**	**$3,396,465**	**$44,238,404**	**$6,153,896**	**$187,820,737**	**$405,806**
Difference	-$136,558	-$3,086,972	$719,345	$2,371,671	$972,176	$464,172	-$242,916	-$97,674	-$1,473,925	$237,564	-$3,072,353	-$25,773
% Increase to Equal Allocated Cost	0.038%	1.7%	-2.1%	-4.5%	-3.8%	-6.5%	8.5%	3.0%	3.4%	-3.7%	2%	7%
Revenue To Cost Ratio	**99.962%**	**98.4%**	**102.1%**	**104.7%**	**103.9%**	**107.0%**	**92.2%**	**97.1%**	**96.7%**	**103.9%**	**98.4%**	**93.6%**
Adjusted Revenues at Existing Rates	$360,678,900	$185,198,536	$34,287,738	$52,983,816	$25,765,295	$7,094,309	$2,874,607	$3,300,041	$42,780,676	$6,393,881	$184,818,359	$380,177
Adjusted Revenue to Cost Ratio	**100.0%**	**98.4%**	**102.2%**	**104.7%**	**104.0%**	**107.0%**	**92.2%**	**97.2%**	**96.7%**	**103.9%**	**98.4%**	**93.7%**
Average Unit Costs:												
Customer Cost $ / Per Customer / Month	$38.47	$35.60	$41.71	$98.38	$1,474.98	$5,810.78	$35.69	$40.17	$19,734.79	$7,892.14	$35.60	$43.15
Average Energy Cost $ / kWh	$0.04098	$0.04185	$0.04099	$0.04076	$0.03835	$0.03792	$0.13521	$0.03886	$0.03887	$0.03903	$0.04185	$0.04242
Average Energy + Demand Cost $ / kWh	$0.09106	$0.10255	$0.08731	$0.08477	$0.07705	$0.06615	$0.16865	$0.07120	$0.08511	$0.07442	$0.10253	$0.11385
Demand Charge $ / kW	$12.04	$9.42	$12.47	$15.73	$16.03	$13.34	$43.52	$14.28	$23.05	$14.07	$9.43	$7.91
Combined Average Cost $ / kWh	**$0.1099**	**$0.1390**	**$0.1103**	**$0.0880**	**$0.0797**	**$0.0691**	**$0.2158**	**$0.0843**	**$0.0874**	**$0.0756**	**$0.1390**	**$0.1456**

Fortis BC 2017 COSA

FUNCTIONALIZATION AND CLASSIFICATION OF REVENUE REQUIREMENT SUMMARY BY CUSTOMER CLASS
Schedule 1.2

Forecast Year: 2017	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Production												
Demand (PD)	$46,785,544	$22,083,969	$4,068,306	$7,527,137	$3,597,949	$1,136,502	$107,974	$270,281	$6,767,128	$1,226,299	$22,040,422	$43,546
Energy (PE)	$133,097,241	$56,643,625	$12,471,284	$23,436,708	$11,929,803	$3,639,356	$571,292	$1,565,249	$19,662,169	$3,177,754	$56,525,429	$118,190
Direct Assignment (PDA)												
Transmission												
Demand (TD)	$64,310,485	$32,373,934	$5,217,272	$9,107,704	$4,401,167	$1,571,387	$70,650	$400,331	$9,509,926	$1,658,114	$32,295,918	$78,004
Energy (TE)												
Direct Assignment (TDA)												
Distribution												
Demand (DD)	$53,292,427	$27,718,031	$4,810,161	$8,675,872	$4,039,472	$1,350	$304,208	$632,475	$7,113,730	-$2,874	$27,640,605	$77,555
Energy (DE)												
Customer (DC)	$61,789,894	$49,380,392	$6,986,049	$1,842,773	$814,191	$278,918	$680,882	$527,896	$1,184,087	$94,706	$49,302,957	$88,478
Direct Assignment (DDA)	$1,403,309	$15,438	$2,340	$1,890	$782	-$63	$1,381,426	$233	$1,364	-$102	$15,407	$32
Total	**$360,678,900**	**$188,215,388**	**$33,555,412**	**$50,592,085**	**$24,783,364**	**$6,627,451**	**$3,116,434**	**$3,396,465**	**$44,238,404**	**$6,153,896**	**$187,820,737**	**$405,806**
Total Cost / Function												
Production	$179,882,785	$78,727,594	$16,539,590	$30,963,845	$15,527,752	$4,775,859	$679,267	$1,835,530	$26,429,297	$4,404,052	$78,565,851	$161,736
Transmission	$64,310,485	$32,373,934	$5,217,272	$9,107,704	$4,401,167	$1,571,387	$70,650	$400,331	$9,509,926	$1,658,114	$32,295,918	$78,004
Distribution	$116,485,630	$77,113,861	$11,798,550	$10,520,536	$4,854,445	$280,205	$2,366,517	$1,160,605	$8,299,182	$91,729	$76,958,968	$166,066
Total Cost / Function	**$360,678,900**	**$188,215,388**	**$33,555,412**	**$50,592,085**	**$24,783,364**	**$6,627,451**	**$3,116,434**	**$3,396,465**	**$44,238,404**	**$6,153,896**	**$187,820,737**	**$405,806**
Total Cost / Classifier												
Demand	$164,388,456	$82,175,933	$14,095,739	$25,310,714	$12,038,588	$2,709,240	$482,833	$1,303,087	$23,390,784	$2,881,539	$81,976,945	$199,105
Energy	$133,097,241	$56,643,625	$12,471,284	$23,436,708	$11,929,803	$3,639,356	$571,292	$1,565,249	$19,662,169	$3,177,754	$56,525,429	$118,190
Customer	$61,789,894	$49,380,392	$6,986,049	$1,842,773	$814,191	$278,918	$680,882	$527,896	$1,184,087	$94,706	$49,302,957	$88,478
Direct Assignment	$1,403,309	$15,438	$2,340	$1,890	$782	-$63	$1,381,426	$233	$1,364	-$102	$15,407	$32
Total Cost / Classifier	**$360,678,900**	**$188,215,388**	**$33,555,412**	**$50,592,085**	**$24,783,364**	**$6,627,451**	**$3,116,434**	**$3,396,465**	**$44,238,404**	**$6,153,896**	**$187,820,737**	**$405,806**

Fortis BC 2017 COSA

FUNCTIONALIZATION AND CLASSIFICATION OF RATE BASE SUMMARY BY CUSTOMER CLASS
Schedule 1.3

Mid-year	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Production												
Demand (PD)	$46,143,419	$20,353,191	$4,210,246	$7,825,428	$3,933,744	$1,233,918	$168,986	$501,513	$6,808,492	$1,107,900	$20,309,504	$43,687
Energy (PE)	$185,273,517	$80,767,596	$17,052,892	$31,812,405	$16,052,293	$4,998,887	$717,175	$2,100,920	$27,356,071	$4,415,279	$80,595,255	$172,341
Direct Assignment (PDA)												
Transmission												
Demand (TD)	$350,148,881	$176,429,538	$28,436,985	$49,541,690	$23,935,899	$8,527,695	$411,571	$2,186,713	$51,684,550	$8,994,240	$176,004,722	$424,815
Energy (TE)												
Direct Assignment (TDA)												
Distribution												
Demand (DD)	$350,672,646	$179,652,256	$31,412,243	$58,328,451	$27,311,478	$119	$1,702,919	$4,190,267	$48,074,876	$38	$179,141,419	$510,839
Energy (DE)												
Customer (DC)	$342,717,522	$276,369,562	$39,682,972	$9,802,563	$2,470,108	$1,642,827	$3,424,830	$2,838,436	$5,952,761	$533,463	$275,939,317	$463,580
Direct Assignment (DDA)	$9,567,014	$344	$53	$51	$22	$1	$9,566,497	$5	$40	$0	$343	$1
Total	**$1,284,523,000**	**$733,572,486**	**$120,795,391**	**$157,310,589**	**$73,703,544**	**$16,403,447**	**$15,991,978**	**$11,817,855**	**$139,876,791**	**$15,050,920**	**$731,990,560**	**$1,615,264**
Total Cost / Function												
Production	$231,416,936	$101,120,787	$21,263,138	$39,637,834	$19,986,037	$6,232,805	$886,162	$2,602,433	$34,164,563	$5,523,179	$100,904,759	$216,028
Transmission	$350,148,881	$176,429,538	$28,436,985	$49,541,690	$23,935,899	$8,527,695	$411,571	$2,186,713	$51,684,550	$8,994,240	$176,004,722	$424,815
Distribution	$702,957,183	$456,022,161	$71,095,268	$68,131,065	$29,781,608	$1,642,947	$14,694,246	$7,028,709	$54,027,678	$533,502	$455,081,079	$974,421
Total Cost / Function	**$1,284,523,000**	**$733,572,486**	**$120,795,391**	**$157,310,589**	**$73,703,544**	**$16,403,447**	**$15,991,978**	**$11,817,855**	**$139,876,791**	**$15,050,920**	**$731,990,560**	**$1,615,264**
Total Cost / Classifier												
Demand	$746,964,946	$376,434,984	$64,059,474	$115,695,570	$55,181,121	$9,761,732	$2,283,476	$6,878,493	$106,567,918	$10,102,178	$375,455,645	$979,342
Energy	$185,273,517	$80,767,596	$17,052,892	$31,812,405	$16,052,293	$4,998,887	$717,175	$2,100,920	$27,356,071	$4,415,279	$80,595,255	$172,341
Customer	$342,717,522	$276,369,562	$39,682,972	$9,802,563	$2,470,108	$1,642,827	$3,424,830	$2,838,436	$5,952,761	$533,463	$275,939,317	$463,580
Direct Assignment	$9,567,014	$344	$53	$51	$22	$1	$9,566,497	$5	$40	$0	$343	$1
Total Cost / Classifier	**$1,284,523,000**	**$733,572,486**	**$120,795,391**	**$157,310,589**	**$73,703,544**	**$16,403,447**	**$15,991,978**	**$11,817,855**	**$139,876,791**	**$15,050,920**	**$731,990,560**	**$1,615,264**

Fortis BC 2017 COSA

SUMMARY OF REVENUE REQUIREMENT COST ALLOCATION
Schedule 1.4

Forecast Year: 2017	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Hydraulic Power Generation	$13,555,250	$5,923,363	$1,245,382	$2,321,286	$1,170,572	$365,206	$51,900	$152,758	$2,001,455	$323,329	$5,910,695	$12,668
Purchased Power Supply/Other	$138,603,985	$60,728,132	$12,747,653	$23,880,482	$11,954,714	$3,659,827	$523,674	$1,370,198	$20,323,601	$3,415,704	$60,604,863	$123,269
Total Production	$152,159,234	$66,651,495	$13,993,035	$26,201,767	$13,125,286	$4,025,033	$575,573	$1,522,956	$22,325,056	$3,739,034	$66,515,558	$135,937
Total Transmission	$18,332,780	$9,237,339	$1,488,878	$2,593,859	$1,253,214	$446,485	$21,549	$114,490	$2,706,053	$470,912	$9,215,097	$22,242
Total Distribution	$10,428,018	$7,365,436	$1,112,503	$769,231	$306,326	$33,338	$159,873	$98,571	$571,917	$10,824	$7,351,710	$14,401
Total Operation & Maintenance	**$180,920,032**	**$83,254,269**	**$16,594,416**	**$29,564,857**	**$14,684,826**	**$4,504,857**	**$756,995**	**$1,736,017**	**$25,603,026**	**$4,220,770**	**$83,082,364**	**$172,580**
Total O&M w/o Purchased Power Supply & A&G	**$48,785,099**	**$27,712,280**	**$4,472,899**	**$5,754,406**	**$3,049,625**	**$872,814**	**$326,438**	**$429,946**	**$5,345,186**	**$821,506**	**$27,655,977**	**$62,830**
Total Customer Service, Accounts & Sale	$6,469,051	$5,186,142	$626,136	$70,030	$319,513	$27,784	$93,117	$64,128	$65,761	$16,440	$5,178,476	$13,518
Total Administrative & General	$12,999,425	$7,228,552	$1,218,727	$1,652,122	$782,126	$182,195	$194,543	$123,503	$1,452,747	$164,911	$7,213,032	$15,814
Total O&M plus A&G	**$200,388,508**	**$95,668,963**	**$18,439,279**	**$31,287,009**	**$15,786,465**	**$4,714,836**	**$1,044,654**	**$1,923,647**	**$27,121,533**	**$4,402,121**	**$95,473,872**	**$201,912**
Total Depreciation	$55,657,000	$33,220,760	$5,284,502	$6,343,625	$2,914,265	$573,885	$731,820	$510,461	$5,552,026	$525,656	$33,150,353	$71,850
Total Property Taxes	$16,052,000	$9,416,218	$1,517,360	$1,885,788	$874,158	$185,506	$197,706	$147,930	$1,657,025	$170,309	$9,396,230	$20,374
Total Return and Income Taxes	$98,086,000	$56,015,494	$9,223,919	$12,012,215	$5,627,992	$1,252,565	$1,221,145	$902,410	$10,680,973	$1,149,286	$55,894,699	$123,341
Revenue Requirement Before Other Revenues	**$370,183,508**	**$194,321,435**	**$34,465,061**	**$51,528,637**	**$25,202,880**	**$6,726,792**	**$3,195,326**	**$3,484,448**	**$45,011,557**	**$6,247,372**	**$193,915,154**	**$417,477**
Total Other Revenues	$9,504,608	$6,106,047	$909,649	$936,552	$419,517	$99,341	$78,892	$87,983	$773,152	$93,476	$6,094,417	$11,672
REVENUE REQUIREMENT for COST ALLOCATION	**$360,678,900**	**$188,215,388**	**$33,555,412**	**$50,592,085**	**$24,783,364**	**$6,627,451**	**$3,116,434**	**$3,396,465**	**$44,238,404**	**$6,153,896**	**$187,820,737**	**$405,806**

Fortis BC 2017 COSA

SUMMARY OF RATE BASE COST ALLOCATIONS
Schedule 1.5

Mid-year	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Total Production Plant	$238,463,500	$104,203,602	$21,908,710	$40,835,979	$20,592,661	$6,424,696	$913,019	$2,687,310	$35,209,524	$5,688,001	$103,980,752	$222,850
Total Transmission Plant	$442,836,000	$223,131,802	$35,964,475	$62,655,759	$30,271,917	$10,785,042	$520,517	$2,765,553	$65,365,850	$11,375,085	$222,594,535	$537,267
Total Distribution Plant	$1,010,725,500	$667,472,331	$101,922,423	$94,508,327	$40,771,622	$2,019,599	$19,609,630	$10,067,115	$73,698,766	$655,687	$666,116,607	$1,396,617
Total Transmission & Distribution	$1,453,561,500	$890,604,133	$137,886,898	$157,164,087	$71,043,539	$12,804,641	$20,130,147	$12,832,667	$139,064,616	$12,030,771	$888,711,142	$1,933,885
Total General Plant	$251,170,000	$145,206,979	$23,904,916	$30,149,554	$14,138,057	$3,340,954	$2,759,949	$2,371,916	$26,291,169	$3,006,507	$144,904,838	$308,097
Total Plant Before General Plant & Intangible	**$1,692,025,000**	**$994,807,735**	**$159,795,608**	**$198,000,065**	**$91,636,200**	**$19,229,336**	**$21,043,166**	**$15,519,977**	**$174,274,140**	**$17,718,772**	**$992,691,893**	**$2,156,735**
Total Gross Plant in Service	**$1,943,195,000**	**$1,140,014,714**	**$183,700,524**	**$228,149,619**	**$105,774,257**	**$22,570,291**	**$23,803,115**	**$17,891,893**	**$200,565,309**	**$20,725,279**	**$1,137,596,731**	**$2,464,832**
Total Accumulated Depreciation	$577,273,500	$338,755,431	$54,582,983	$67,681,203	$31,389,050	$6,784,926	$6,979,581	$5,304,018	$59,563,202	$6,233,105	$338,038,237	$731,155
Total Net Plant	**$1,365,921,500**	**$801,259,283**	**$129,117,541**	**$160,468,416**	**$74,385,207**	**$15,785,364**	**$16,823,534**	**$12,587,875**	**$141,002,107**	**$14,492,174**	**$799,558,493**	**$1,733,677**
Total Working Capital	$5,893,000	$2,711,940	$538,724	$960,592	$481,764	$146,722	$25,822	$56,754	$833,175	$137,506	$2,706,344	$5,689
Total Contributions	-$112,867,000	-$83,753,696	-$11,257,072	-$7,716,404	-$2,910,250		-$1,061,451	-$1,086,524	-$5,081,603		-$83,600,996	-$152,700
SUB-TOTAL RATE BASE	**$1,258,947,500**	**$720,217,528**	**$118,399,193**	**$153,712,604**	**$71,956,721**	**$15,932,087**	**$15,787,904**	**$11,558,105**	**$136,753,679**	**$14,629,680**	**$718,663,842**	**$1,586,666**
Total Other Rate Base Items	$25,575,500	$13,354,958	$2,396,198	$3,597,985	$1,746,823	$471,360	$204,074	$259,749	$3,123,111	$421,241	$13,326,718	$28,598
TOTAL RATE BASE	**$1,284,523,000**	**$733,572,486**	**$120,795,391**	**$157,310,589**	**$73,703,544**	**$16,403,447**	**$15,991,978**	**$11,817,855**	**$139,876,791**	**$15,050,920**	**$731,990,560**	**$1,615,264**

Fortis BC 2017 COSA

SUMMARY OF REVENUE REQUIREMENT UNIT COSTS
BY CUSTOMER CLASS
Schedule 2.1

Forecast Year: 2017	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
	374,694	**154,541**										
Billing Determinants												
Total kVA (with ratchet)	3,654,037			1,212,392	859,910	214,181			1,104,374	263,181		
Total Demand (kW)	13,768,020	8,720,580	1,130,170	1,609,278	751,188	203,065	42,836	91,238	1,014,925	204,739	8,695,402	25,178
Total kVA Contract												
Total Energy (kWh)	3,282,317,076	1,353,778,140	304,323,499	575,109,408	311,098,688	95,976,168	14,441,848	40,288,397	505,880,576	81,420,354	1,350,990,999	2,787,141
Average Monthly Customers	133,853	115,595	13,956	1,561	46	4	1,590	1,095	5	1	115,424	171
Average PODs									2.4	3.0		
											11,705	16,311
Functional Cost											75	147
Production												
Demand (PD)	$46,785,544	$22,083,969	$4,068,306	$7,527,137	$3,597,949	$1,136,502	$107,974	$270,281	$6,767,128	$1,226,299	$22,040,422	$43,546
$/kW	$3.40	$2.53	$3.60	$4.68	$4.79	$5.60	$2.52	$2.96	$6.67	$5.99	$2.53	$1.73
or $/kVa				$6.21	$4.18	$5.31			$6.13	$4.66		
Energy (PE)	$133,097,241	$56,643,625	$12,471,284	$23,436,708	$11,929,803	$3,639,356	$571,292	$1,565,249	$19,662,169	$3,177,754	$56,525,429	$118,190
$/kWh	$0.041	$0.042	$0.041	$0.041	$0.038	$0.038	$0.040	$0.039	$0.039	$0.039	$0.042	$0.042
Transmission												
Demand (TD)	$64,310,485	$32,373,934	$5,217,272	$9,107,704	$4,401,167	$1,571,387	$70,650	$400,331	$9,509,926	$1,658,114	$32,295,918	$78,004
$/kW	$4.67	$3.71	$4.62	$5.66	$5.86	$7.74	$1.65	$4.39	$9.37	$8.10	$3.71	$3.10
or $/kVa				$7.51	$5.12	$7.34			$8.61	$6.30		
Distribution												
Demand (DD)	$53,292,427	$27,718,031	$4,810,161	$8,675,872	$4,039,472	$1,350	$304,208	$632,475	$7,113,730	-$2,874	$27,640,605	$77,555
$/kW	$3.87	$3.18	$4.26	$5.39	$5.38	$0.01	$7.10	$6.93	$7.01	-$0.01	$3.18	$3.08
or $/kVa				$7.16	$4.70	$0.01			$6.44	-$0.01		
Customer (DC)	$61,789,894	$49,380,392	$6,986,049	$1,842,773	$814,191	$278,918	$680,882	$527,896	$1,184,087	$94,706	$49,302,957	$88,478
$/Customer/Month	$38.47	$35.60	$41.71	$98.38	$1,474.98	$5,810.78	$35.69	$40.17	$19,734.79	$7,892.14	$35.60	$43.15
Direct Assignment (DDA)	$1,403,309	$15,438	$2,340	$1,890	$782	-$63	$1,381,426	$233	$1,364	-$102	$15,407	$32
$/kW	$0.10	$0.00	$0.00	$0.00	$0.00	$0.00	$32.25	$0.00	$0.00	$0.00	$0.00	$0.00
$/kVa				$0.00	$0.00	$0.00			$0.00	$0.00		
$/kWh	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.096	$0.000	$0.000	$0.000	$0.000	$0.000
Total	**$360,678,900**	**$188,215,388**	**$33,555,412**	**$50,592,085**	**$24,783,364**	**$6,627,451**	**$3,116,434**	**$3,396,465**	**$44,238,404**	**$6,153,896**	**$187,820,737**	**$405,806**
Total		6.89	73%	4.48								
$/kW	**$12.04**	**$9.42**	**$12.47**	**$15.73**	**$16.03**	**$13.34**	**$43.52**	**$14.28**	**$23.05**	**$14.07**	**$9.43**	**$7.91**
$/kVa					**$14.00**	**$12.65**			**$21.18**	**$10.95**		
$/kWh	**$0.0410**	**$0.0419**	**$0.0410**	**$0.0408**	**$0.0383**	**$0.0379**	**$0.1352**	**$0.0389**	**$0.0389**	**$0.0390**	**$0.0419**	**$0.0424**
$/kWh (energy only)	**$0.0911**	**$0.1026**	**$0.0873**	**$0.0848**	**$0.0770**	**$0.0661**	**$0.1686**	**$0.0712**	**$0.0851**	**$0.0744**	**$0.1025**	**$0.1139**
$/Customer/Month	**$38.47**	**$35.60**	**$41.71**	**$98.38**	**$1,474.98**	**$5,810.78**	**$35.69**	**$40.17**	**$19,734.79**	**$7,892.14**	**$35.60**	**$43.15**
$/POD/Month									**$8,222.83**	**$2,630.71**		
Total Average Cost per kWh	**$0.1099**	**$0.1390**	**$0.1103**	**$0.0880**	**$0.0797**	**$0.0691**	**$0.2158**	**$0.0843**	**$0.0874**	**$0.0756**	**$0.1390**	**$0.1456**

Fortis BC 2017 COSA

SUMMARY OF RATE BASE UNIT COST
BY CUSTOMER CLASS
Schedule 2.2

Forecast Year: 2017	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Billing Determinants												
Total kVa	3,654,037			1,212,392	859,910	214,181			1,104,374	263,181		
Total Demand (kW)	13,768,020	8,720,580	1,130,170	1,609,278	751,188	203,065	42,836	91,238	1,014,925	204,739	8,695,402	25,178
Total Energy (kWh)	3,282,317,076	1,353,778,140	304,323,499	575,109,408	311,098,688	95,976,168	14,441,848	40,288,397	505,880,576	81,420,354	1,350,990,999	2,787,141
Average Monthly Customers	133,853	115,595	13,956	1,561	46	4	1,590	1,095	5	1	115,424	171
Functional Cost												
Production												
Demand (PD)	$46,143,419	$20,353,191	$4,210,246	$7,825,428	$3,933,744	$1,233,918	$168,986	$501,513	$6,808,492	$1,107,900	$20,309,504	$43,687
$/kW		$2.33	$3.73	$4.86	$5.24	$6.08	$3.94	$5.50	$6.71	$5.41	$2.34	$1.74
or $/kVa				$6.45	$4.57	$5.76			$6.17	$4.21		
Energy (PE)	$185,273,517	$80,767,596	$17,052,892	$31,812,405	$16,052,293	$4,998,887	$717,175	$2,100,920	$27,356,071	$4,415,279	$80,595,255	$172,341
$/kWh	$0.056	$0.060	$0.056	$0.055	$0.052	$0.052	$0.050	$0.052	$0.054	$0.054	$0.060	$0.062
Transmission												
Demand (TD)	$350,148,881	$176,429,538	$28,436,985	$49,541,690	$23,935,899	$8,527,695	$411,571	$2,186,713	$51,684,550	$8,994,240	$176,004,722	$424,815
$/kW		$20.23	$25.16	$30.79	$31.86	$41.99	$9.61	$23.97	$50.92	$43.93	$20.24	$16.87
or $/kVa				$40.86	$27.84	$39.82			$46.80	$34.18		
Distribution												
Demand (DD)	$350,672,646	$179,652,256	$31,412,243	$58,328,451	$27,311,478	$119	$1,702,919	$4,190,267	$48,074,876	$38	$179,141,419	$510,839
$/kW		$20.60	$27.79	$36.25	$36.36	$0.00	$39.75	$45.93	$47.37	$0.00	$20.60	$20.29
or $/kVa				$48.11	$31.76	$0.00			$43.53	$0.00		
Customer (DC)	$342,717,522	$276,369,562	$39,682,972	$9,802,563	$2,470,108	$1,642,827	$3,424,830	$2,838,436	$5,952,761	$533,463	$275,939,317	$463,580
$/Customer/Month		$199	$237	$523	$4,475	$34,226	$179	$216	$99,213	$44,455	$199	$226
Direct Assignment (DDA)	$9,567,014	$344	$53	$51	$22	$1	$9,566,497	$5	$40	$0	$343	$1
$/kW		$0.00	$0.00	$0.00	$0.00	$0.00	$223.33	$0.00	$0.00	$0.00	$0.00	$0.00
$/kVa				$0.00	$0.00	$0.00			$0.00	$0.00		
$/kWh		$0.000	$0.000	$0.000	$0.000	$0.000	$0.662	$0.000	$0.000	$0.000	$0.000	$0.000
Total	**$1,284,523,000**	**$733,572,486**	**$120,795,391**	**$157,310,589**	**$73,703,544**	**$16,403,447**	**$15,991,978**	**$11,817,855**	**$139,876,791**	**$15,050,920**	**$731,990,560**	**$1,615,264**

Fortis BC 2017 COSA

INPUT REVENUE REQUIREMENT
Schedule 3.1

Source: Page 21 April 28, 2017 Annual Report for 2016, Schedule 6 Oct 5, 2016 Evidentiary Update for 2017

FERC Account	Operation & Maintenance Expense	2016 Actual Cost, $	2017 Review Cost, $	2017 Review Source	2017 Cost, $	Function	Classification Factor	Classification Method
535.00	Op. Supervision & Engineering	$408,000			$424,064	P	RBG	On the Basis of Generation Rate Base
536.00	Water for Power	$10,182,000	$10,328,000	Sched 19 Line 27	$10,328,000	P	RBG	On the Basis of Generation Rate Base
537.00	Hydraulic Expenses					P	RBG	On the Basis of Generation Rate Base
538.00	Electric Expenses					P	RBG	On the Basis of Generation Rate Base
539.00	Misc. Hydraulic Power Generation					P	RBG	On the Basis of Generation Rate Base
540.00	Rents					P	RBG	On the Basis of Generation Rate Base
540.10	Op. Supplies					P	RBG	On the Basis of Generation Rate Base
541.00	Maint. Supervision & Engineering					P	RBG	On the Basis of Generation Rate Base
542.00	Structures	$643,000			$668,316	P	RBG	On the Basis of Generation Rate Base
543.00	Dams & Waterways	$172,000			$178,772	P	RBG	On the Basis of Generation Rate Base
544.00	Electric Plant	$1,575,000			$1,637,011	P	RBG	On the Basis of Generation Rate Base
545.00	Other Plant	$307,000			$319,087	P	RBG	On the Basis of Generation Rate Base
545.10	Maint. of Hydraulic Production Plant					P	RBG	On the Basis of Generation Rate Base
	Other Power Generation							
546.00	Op. Supervision & Engineering					P	OPG	N/A
547.00	Fuel					P	kWh	Annual Energy (kWh)
548.00	Generation					P	kWh	Annual Energy (kWh)
549.00	Misc. Other Power Generation					P	kWh	Annual Energy (kWh)
550.00	Rents					P	kWh	Annual Energy (kWh)
550.10	Op. Supplies					P	kWh	Annual Energy (kWh)
551.00	Maint. Supervision & Engineering					P	kWh	Annual Energy (kWh)
552.00	Maint. of Structures					P	kWh	Annual Energy (kWh)
553.00	Maint. of Generating and Electric Plant					P	kWh	Annual Energy (kWh)
554.00	Maint. Misc. Other Generation Plant					P	kWh	Annual Energy (kWh)
554.10	Maint. of Other Production Plant					P	kWh	Annual Energy (kWh)
	Purchased Power Supply/Other							
555.00	Purchased Power - Energy Charges	$123,169,000	$100,026,782	Power Supply	$100,026,782	P	PURCHkWh	On the Basis of Energy Purchases Weighted by Month
555.00	Purchased Power - Demand Charges		$36,188,726	Power Supply	$36,188,726	P	PURCHkW	On the Basis of Demand Purchases Weighted by Month
556.00	System Control	$2,298,000			$2,388,477	P	CP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
	Base Power Supply							
XXXX	Irrigation On-Peak Credit					P	DA2	N/A
XXXX	Irrigation Off-Peak Credit					P	DA2	N/A
	Total Purchased Power	$123,169,000	$136,215,508		$136,215,508			
	Total Production	$138,754,000	$146,543,508		$152,159,234			
	Transmission							
560.10	Op. Supervision & Engineering	$2,228,000			$2,315,721	T	RBT	On the Basis of Transmission Rate Base
560.20	System Planning	$3,074,000			$3,195,029	T	RBT	On the Basis of Transmission Rate Base
561.00	Load Dispatching	$1,357,000			$1,410,428	T	RBT	On the Basis of Transmission Rate Base
562.00	Transmission Station Expense	$847,000			$880,348	T	RBT	On the Basis of Transmission Rate Base
563.10	Transmission Line Maintenance	$539,000			$560,221	T	RBT	On the Basis of Transmission Rate Base
563.20	Transmission TROW Maintenance	$1,507,000			$1,566,333	T	RBT	On the Basis of Transmission Rate Base
565.00	Wheeling	$4,815,000	$4,928,000	Sched 19 Line 22	$4,928,000	T	RBT	On the Basis of Transmission Rate Base
567.00	Rents	$3,345,000			$3,476,699	T	RBT	On the Basis of Transmission Rate Base
567.10	Op. Supplies					T	RBT	On the Basis of Transmission Rate Base
568.00	Maint. Supervision & Engineering					T	RBT	On the Basis of Transmission Rate Base

Fortis BC 2017 COSA

INPUT REVENUE REQUIREMENT
Schedule 3.1

Source: Page 21 April 28, 2017 Annual Report for 2016, Schedule 6 Oct 5, 2016 Evidentiary Update for 2017

		2016 Actual Cost, $	2017 Review Cost, $	2017 Review Source	2017 Cost, $	Classification Function	Classification Factor	Classification Method
569.00	Maint. of Structures					T	RBT	On the Basis of Transmission Rate Base
570.00	Maint. of Station Equipment					T	RBT	On the Basis of Transmission Rate Base
571.00	Maint. of Overhead Lines					T	RBT	On the Basis of Transmission Rate Base
572.00	Maint. Of Underground Lines					T	RBT	On the Basis of Transmission Rate Base
573.00	Maint. of Misc. Transmission Plant					T	RBT	On the Basis of Transmission Rate Base
574.00	Maint. Of Transmission Plant					T	RBT	On the Basis of Transmission Rate Base
	Total Transmission	$17,712,000	$4,928,000		$18,332,780			
	Distribution							
583.10	Distribution Line Maintenance	$3,401,000			$3,534,904	D		On the Basis of RBD Poles, Towers & Fixtures
583.20	Distribution ROW Maintenance	$3,817,000			$3,967,283	D		On the Basis of RBD Poles, Towers & Fixtures
586.00	Meter Expenses	$708,000			$735,875	D		On the Basis of RBD Meters
592.00	Distribution Station Expense	$1,790,000			$1,860,476	D		On the Basis of RBD Station Equipment
596.00	Street Lighting	$68,000			$70,677	D	DA1	On the Basis of RBD Street Lights and Signal Systems
598.00	Other Plant	$249,000			$258,804	D	RBD	On the Basis of Distribution Rate Base
	Total Distribution	$10,033,000			$10,428,018			
	Total Operation & Maintenance	$166,499,000	$151,471,508		$180,920,032			
	Customer Service, Accounts, & Sales							
901.00	Supervision & Administration	$1,722,000			$1,789,798	D		As All Other Customer Service Expense
902.00	Meter Reading	$231,000			$240,095	D	CUSTW	Customers Weighted for Accounting/Metering
903.00	Customer Billing	$594,000			$617,387	D	CUSTW	Customers Weighted for Accounting/Metering
904.00	Credit & Collections	$989,000			$1,027,939	D	CUSTR	Retail Customers
910.00	Customer Assistance	$2,688,000			$2,793,832	D	CUSTW	Customers Weighted for Accounting/Metering
911.00	Energy Management Promotion					SS	DSM	Classified 72% Energy, 17% Demand & 12% T&D
	Total Customer Service, Accounts & Sales	$6,224,000			$6,469,051			
	Total O&M w/o Purchased Power Supply & A&G	$49,554,000	$15,256,000		$51,173,575			

Fortis BC 2017 COSA

INPUT REVENUE REQUIREMENT
Schedule 3.1

Source: Page 21 April 28, 2017 Annual Report for 2016, Schedule 6 Oct 5, 2016 Evidentiary Update for 2017

		2016 Actual Cost, $	2017 Review Cost, $	2017 Review Source	2017 Cost, $	Function	Classification Factor	Classification Method
	Administrative & General							
920.10	Executive & Senior Management	$524,000			$544,631	SS	LABOR	On the Basis of Labor Ratios
920.20	Legal	$692,000			$719,245	SS	LABOR	On the Basis of Labor Ratios
920.30	Human Resources	$599,000			$622,584	SS	LABOR	On the Basis of Labor Ratios
920.40	Regulatory & Finance	$1,223,000			$1,271,152	SS	LABOR	On the Basis of Labor Ratios
920.60	Information Services	$1,216,000			$1,263,876	SS	LABOR	On the Basis of Labor Ratios
920.70	Materials Management	-$10,000			-$10,394	SS	LABOR	On the Basis of Labor Ratios
	Other	$308,000			$320,127	SS	LABOR	On the Basis of Labor Ratios
921.10	Executive & Senior Management Expenses	$45,000			$46,772	SS	LABOR	On the Basis of Labor Ratios
921.20	Legal Expenses	$228,000			$236,977	SS	LABOR	On the Basis of Labor Ratios
921.30	Human Resources Expenses	$98,000			$101,858	SS	LABOR	On the Basis of Labor Ratios
921.40	Regulatory & Finance Expenses	$142,000			$147,591	SS	LABOR	On the Basis of Labor Ratios
921.60	Information Services Expenses	$1,527,000			$1,587,121	SS	LABOR	On the Basis of Labor Ratios
921.70	Materials Management	$343,000			$356,505	SS	LABOR	On the Basis of Labor Ratios
XXXX	Other Expenses	$181,000			$188,126	SS	LABOR	On the Basis of Labor Ratios
XXXX	Other Items	$5,391,000			$5,603,254	SS	LABOR	On the Basis of Labor Ratios
	Total Administrative & General	$12,507,000			$12,999,425			
	Total O&M plus A&G	$185,230,000	$151,471,508		$200,388,508			
	Depreciation							
403.30	Generation Plant		$4,507,000	Sched 7 Line 9	$4,507,000	P	RBG	On the Basis of Generation Rate Base
403.50	Transmission Plant		$10,447,000	Sched 7 Line 17	$10,447,000	T	RBT	On the Basis of Transmission Rate Base
403.60	Distribution Plant		$27,685,000	Sched 7 Line 30	$27,685,000	D	RBD	On the Basis of Distribution Rate Base
403.70	General Plant And Deferred Charges		$13,407,000	Sched 7.1 Line 12	$13,407,000	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Amortization		-$389,000	Sched 21 Line 9	-$389,000	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Total Depreciation		$55,657,000	Sched 21 Line 11	$55,657,000			
	Taxes							
408.05	Property				$16,052,000	SS	NETPLT	On the Basis of Net Plant
	Total Property Taxes		$16,052,000	Sched 22 Line 7	$16,052,000			
	Return and Income Taxes							
	Incentive Adjustments					SS	RBASE	On the Basis of Total Rate Base
	Income Tax		$10,849,000	Sched 24 Line 13	$10,849,000	SS	RBASE	On the Basis of Total Rate Base
	Return on Rate Base		$87,237,000	Sched 24 Line 1	$87,237,000	SS	RBASE	On the Basis of Total Rate Base
	Interest on Non Rate Base Deferral Account					SS	RBASE	On the Basis of Total Rate Base
	Total Return and Income Taxes		$98,086,000		$98,086,000			
	Revenue Requirement Before Other Revenues	$185,230,000	$321,266,508		$370,183,508			
	Revenue Req. Before Taxes and Other Revenues	$185,230,000	$305,214,508		$354,131,508			
	Other Revenues							
	Electric Apparatus Rental		$4,576,000	Sched 23 Line 1	$4,576,000	SS		On the Basis of RBD Poles, Towers & Fixtures
	Rate 37 Revenue				$1,448,608	SS	RB	On the Basis of All Rate Base
	Contract Revenue		$1,865,000	Sched 23 Line 2	$1,865,000	SS	RBG	On the Basis of Generation Rate Base
	Transmission Access Revenue		$1,179,000	Sched 23 Line 3	$1,179,000	SS	RBT	On the Basis of Transmission Rate Base
	Fortis Pacific Holdings					SS	LABOR	On the Basis of Labor Ratios
	Connection Charges		$270,000	Sched 23 Line 5	$270,000	SS	CUSTR	Retail Customers
	NSF Cheque Charges					SS	CUSTR	Retail Customers

Fortis BC 2017 COSA

INPUT REVENUE REQUIREMENT
Schedule 3.1

Source: Page 21 April 28, 2017 Annual Report for 2016, Schedule 6 Oct 5, 2016 Evidentiary Update for 2017

	2016 Actual Cost, $	2017 Review Cost, $	2017 Review Source	2017 Cost, $	Classification Function	Classification Factor	Classification Method
Sundry Revenue		$142,000	Sched 23 Line 6	$142,000	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
Investment Income		$24,000	Sched 23 Line 4	$24,000	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
Total Other Revenues		$8,056,000		$9,504,608			
REVENUE REQUIREMENT for COST ALLOCATION		$362,127,508		$360,678,900			
Net O&M Expense	$47,064,000	$48,917,000	Sched 20 Line 29	3.9%			

Fortis BC 2017 COSA

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.2

	2017 Total Expenses	Production Demand PD	Production Energy PE	Production Direct Assignment PDA	Transmission Demand TD	Transmission Energy TE	Transmission Direct Assignment TDA	Distribution Demand DD	Distribution Energy DE	Distribution Customer DC	Distribution Direct Assignment DDA
Operation & Maintenance Expense											
Op. Supervision & Engineering	$424,064	$84,096	$339,968								
Water for Power	$10,328,000	$2,048,139	$8,279,861								
Hydraulic Expenses											
Electric Expenses											
Misc. Hydraulic Power Generation											
Rents											
Op. Supplies											
Maint. Supervision & Engineering											
Structures	$668,316	$132,533	$535,783								
Dams & Waterways	$178,772	$35,452	$143,320								
Electric Plant	$1,637,011	$324,635	$1,312,376								
Other Plant	$319,087	$63,278	$255,809								
Maint. of Hydraulic Production Plant											
Other Power Generation											
Op. Supervision & Engineering											
Fuel											
Generation											
Misc. Other Power Generation											
Rents											
Op. Supplies											
Maint. Supervision & Engineering											
Maint. of Structures											
Maint. of Generating and Electric Plant											
Maint. Misc. Other Generation Plant											
Maint. of Other Production Plant											
Purchased Power Supply/Other											
Purchased Power - Energy Charges	$100,026,782		$100,026,782								
Purchased Power - Demand Charges	$36,188,726	$36,188,726									
System Control	$2,388,477	$2,388,477									
Total Purchased Power	$100,026,782	$36,188,726	$100,026,782								
Total Production	$152,159,234	$41,265,335	$110,893,899								
Transmission											
Op. Supervision & Engineering	$2,315,721				$2,315,721						
System Planning	$3,195,029				$3,195,029						
Load Dispatching	$1,410,428				$1,410,428						
Transmission Station Expense	$880,348				$880,348						

Fortis BC 2017 COSA

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.2

	2017 Total Expenses	Production Demand PD	Production Energy PE	Production Direct Assignment PDA	Transmission Demand TD	Transmission Energy TE	Transmission Direct Assignment TDA	Distribution Demand DD	Distribution Energy DE	Distribution Customer DC	Distribution Direct Assignment DDA
Transmission Line Maintenance	$560,221				$560,221						
Transmission TROW Maintenance	$1,566,333				$1,566,333						
Wheeling	$4,928,000				$4,928,000						
Rents	$3,476,699				$3,476,699						
Total Transmission	$18,332,780				$18,332,780						
Distribution											
Distribution Line Maintenance	$3,534,904							$671,632		$2,863,272	
Distribution ROW Maintenance	$3,967,283							$753,784		$3,213,499	
Meter Expenses	$735,875									$735,875	
Distribution Station Expense	$1,860,476							$1,860,476			
Street Lighting	$70,677										$70,677
Other Plant	$258,804							$122,529		$133,210	$3,064
Total Distribution	$10,428,018							$3,408,421		$6,945,857	$73,741
Total Operation & Maintenance	$180,920,032	$41,265,335	$110,893,899		$18,332,780			$3,408,421		$6,945,857	$73,741
Customer Service, Accounts, & Sales											
Supervision & Administration	$1,789,798									$1,789,798	
Meter Reading	$240,095									$240,095	
Customer Billing	$617,387									$617,387	
Credit & Collections	$1,027,939									$1,027,939	
Customer Assistance	$2,793,832									$2,793,832	
Energy Management Promotion											
Total Customer Service, Accounts & Sales	$6,469,051									$6,469,051	
Total O&M w/o Purchased Power Supply & A&G	$48,785,099	$2,688,133	$10,867,117		$18,332,780			$3,408,421		$13,414,907	$73,741

Fortis BC 2017 COSA

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.2

	2017 Total Expenses	Production Demand PD	Production Energy PE	Production Direct Assignment PDA	Transmission Demand TD	Transmission Energy TE	Transmission Direct Assignment TDA	Distribution Demand DD	Distribution Energy DE	Distribution Customer DC	Distribution Direct Assignment DDA
Administrative & General											
Executive & Senior Management	$544,631	$30,308	$122,525		$119,363			$128,983		$140,226	$3,225
Legal	$719,245	$40,026	$161,808		$157,632			$170,336		$185,184	$4,259
Human Resources	$622,584	$34,646	$140,062		$136,448			$147,444		$160,296	$3,687
Regulatory & Finance	$1,271,152	$70,739	$285,970		$278,590			$301,042		$327,283	$7,528
Information Services	$1,263,876	$70,334	$284,334		$276,996			$299,319		$325,410	$7,485
Materials Management	-$10,394	-$578	-$2,338		-$2,278			-$2,462		-$2,676	-$62
Other	$320,127	$17,815	$72,019		$70,160			$75,814		$82,423	$1,896
Executive & Senior Management Expenses	$46,772	$2,603	$10,522		$10,251			$11,077		$12,042	$277
Legal Expenses	$236,977	$13,188	$53,313		$51,937			$56,122		$61,014	$1,403
Human Resources Expenses	$101,858	$5,668	$22,915		$22,324			$24,123		$26,225	$603
Regulatory & Finance Expenses	$147,591	$8,213	$33,203		$32,347			$34,953		$38,000	$874
Information Services Expenses	$1,587,121	$88,322	$357,054		$347,839			$375,871		$408,635	$9,399
Materials Management	$356,505	$19,839	$80,203		$78,133			$84,429		$91,789	$2,111
	$188,126	$10,469	$42,323		$41,230			$44,553		$48,437	$1,114
	$5,603,254	$311,817	$1,260,561		$1,228,030			$1,326,995		$1,442,667	$33,183
Total Administrative & General	$12,999,425	$723,409	$2,924,474		$2,849,001			$3,078,599		$3,346,956	$76,984
Total O&M plus A&G	$200,388,508	$41,988,745	$113,818,373		$21,181,781			$6,487,020		$16,761,864	$150,725
Depreciation											
Generation Plant	$4,507,000	$893,780	$3,613,220								
Transmission Plant	$10,447,000				$10,447,000						
Distribution Plant	$27,685,000							$13,107,344		$14,249,893	$327,763
General Plant And Deferred Charges	$13,407,000	$374,705	$1,514,794		$3,508,874			$3,791,650		$4,122,163	$94,814
Amortization	-$389,000	-$64,574	-$278,524		-$13,984			-$15,292		-$16,625	
Total Depreciation	$55,657,000	$1,203,912	$4,849,490		$13,941,890			$16,883,702		$18,355,430	$422,578
Taxes											
Property	$16,052,000	$495,907	$2,004,767		$4,066,816			$4,456,245		$4,916,833	$111,433
Total Property Taxes	$16,052,000	$495,907	$2,004,767		$4,066,816			$4,456,245		$4,916,833	$111,433
Return and Income Taxes											
Incentive Adjustments											
Income Tax	$10,849,000	$389,724	$1,564,808		$2,957,335			$2,961,759		$2,894,571	$80,802
Return on Rate Base	$87,237,000	$3,133,781	$12,582,652		$23,779,985			$23,815,556		$23,275,292	$649,734
Interest on Non Rate Base Deferral Account											
Total Return and Income Taxes	$98,086,000	$3,523,505	$14,147,460		$26,737,320			$26,777,315		$26,169,863	$730,536
Revenue Requirement Before Other Revenues	$370,183,508	$47,212,068	$134,820,090		$65,927,807			$54,604,281		$66,203,989	$1,415,272
Revenue Req. Before Taxes and Other Revenues	$354,131,508	$46,716,161	$132,815,324		$61,860,991			$50,148,037		$61,287,157	$1,303,838
Other Revenues											
Electric Apparatus Rental	$4,576,000							$869,440		$3,706,560	
Rate 37 Revenue	$1,448,608	$52,038	$208,940		$394,877			$395,468		$386,496	$10,789

Fortis BC 2017 COSA

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.2

	2017	**Production**			**Transmission**			**Distribution**			
	Total	Demand	Energy	Direct Assignment	Demand	Energy	Direct Assignment	Demand	Energy	Customer	Direct Assignment
	Expenses	PD	PE	PDA	TD	TE	TDA	DD	DE	DC	DDA
Contract Revenue	$1,865,000	$369,847	$1,495,153								
Transmission Access Revenue	$1,179,000				$1,179,000						
Fortis Pacific Holdings											
Connection Charges	$270,000									$270,000	
NSF Cheque Charges											
Sundry Revenue	$142,000	$3,969	$16,044		$37,164			$40,159		$43,660	$1,004
Investment Income	$24,000	$671	$2,712		$6,281			$6,787		$7,379	$170
Total Other Revenues	$9,504,608	$426,524	$1,722,849		$1,617,322			$1,311,854		$4,414,095	$11,963
REVENUE REQUIREMENT for COST ALLOCATION	$360,678,900	$46,785,544	$133,097,241		$64,310,485			$53,292,427		$61,789,894	$1,403,309

Fortis BC 2017 COSA

REVENUE REQUIREMENT COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 3.3

	2017 Total Expenses	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Operation & Maintenance Expense												
Op. Supervision & Engineering	$424,064	$185,307	$38,961	$72,619	$36,620	$11,425	$1,624	$4,779	$62,614	$10,115	$184,911	$396
Water for Power	$10,328,000	$4,513,122	$948,880	$1,768,631	$891,881	$278,257	$39,543	$116,389	$1,524,946	$246,351	$4,503,470	$9,652
Hydraulic Expenses												
Electric Expenses												
Misc. Hydraulic Power Generation												
Rents												
Op. Supplies												
Maint. Supervision & Engineering												
Structures	$668,316	$292,040	$61,401	$114,447	$57,713	$18,006	$2,559	$7,531	$98,678	$15,941	$291,416	$625
Dams & Waterways	$178,772	$78,120	$16,425	$30,614	$15,438	$4,816	$684	$2,015	$26,396	$4,264	$77,953	$167
Electric Plant	$1,637,011	$715,340	$150,400	$280,332	$141,365	$44,104	$6,268	$18,448	$241,707	$39,047	$713,810	$1,530
Other Plant	$319,087	$139,434	$29,316	$54,642	$27,555	$8,597	$1,222	$3,596	$47,114	$7,611	$139,136	$298
Maint. of Hydraulic Production Plant												
Other Power Generation												
Op. Supervision & Engineering												
Fuel												
Generation												
Misc. Other Power Generation												
Rents												
Op. Supplies												
Maint. Supervision & Engineering												
Maint. of Structures												
Maint. of Generating and Electric Plant												
Maint. Misc. Other Generation Plant												
Maint. of Other Production Plant												
Purchased Power Supply/Other												
Purchased Power - Energy Charges	$100,026,782	$42,233,508	$9,431,822	$17,757,865	$9,064,527	$2,744,743	$446,223	$1,191,449	$14,770,319	$2,386,326	$42,146,107	$87,401
Purchased Power - Demand Charges	$36,188,726	$17,291,142	$3,121,854	$5,784,677	$2,726,913	$856,914	$74,643	$163,832	$5,200,725	$968,026	$17,258,172	$32,970
System Control	$2,388,477	$1,203,482	$193,978	$337,940	$163,274	$58,170	$2,807	$14,916	$352,557	$61,353	$1,200,584	$2,898
Base Power Supply												
Irrigation On-Peak Credit												
Irrigation Off-Peak Credit												
Total Purchased Power	$100,026,782	$42,233,508	$9,431,822	$17,757,865	$9,064,527	$2,744,743	$446,223	$1,191,449	$14,770,319	$2,386,326	$42,146,107	$87,401
Total Production	$152,159,234	$66,651,495	$13,993,035	$26,201,767	$13,125,286	$4,025,033	$575,573	$1,522,956	$22,325,056	$3,739,034	$66,515,558	$135,937
Transmission												
Op. Supervision & Engineering	$2,315,721	$1,166,822	$188,069	$327,646	$158,301	$56,398	$2,722	$14,462	$341,817	$59,484	$1,164,013	$2,810

Fortis BC 2017 COSA

REVENUE REQUIREMENT COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 3.3

	2017 Total Expenses	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
System Planning	$3,195,029	$1,609,880	$259,481	$452,057	$218,410	$77,813	$3,755	$19,953	$471,610	$82,070	$1,606,003	$3,876
Load Dispatching	$1,410,428	$710,672	$114,546	$199,558	$96,416	$34,350	$1,658	$8,808	$208,189	$36,230	$708,961	$1,711
Transmission Station Expense	$880,348	$443,581	$71,497	$124,558	$60,180	$21,440	$1,035	$5,498	$129,946	$22,613	$442,513	$1,068
Transmission Line Maintenance	$560,221	$282,279	$45,498	$79,264	$38,296	$13,644	$658	$3,499	$82,693	$14,390	$281,599	$680
Transmission TROW Maintenance	$1,566,333	$789,229	$127,208	$221,617	$107,073	$38,147	$1,841	$9,782	$231,202	$40,234	$787,328	$1,900
Wheeling	$4,928,000	$2,483,072	$400,223	$697,250	$336,874	$120,019	$5,792	$30,776	$727,409	$126,585	$2,477,093	$5,979
Rents	$3,476,699	$1,751,805	$282,357	$491,909	$237,664	$84,673	$4,087	$21,712	$513,186	$89,306	$1,747,586	$4,218
Op. Supplies												
Maint. Supervision & Engineering												
Maint. of Structures												
Maint. of Station Equipment												
Maint. of Overhead Lines												
Maint. Of Underground Lines												
Maint. of Misc. Transmission Plant												
Maint. Of Transmission Plant												
Total Transmission	$18,332,780	$9,237,339	$1,488,878	$2,593,859	$1,253,214	$446,485	$21,549	$114,490	$2,706,053	$470,912	$9,215,097	$22,242
Distribution												
Distribution Line Maintenance	$3,534,904	$2,734,356	$357,361	$193,526	$66,225		$35,457	$32,873	$115,106		$2,729,627	$4,729
Distribution ROW Maintenance	$3,967,283	$3,068,814	$401,072	$217,197	$74,326		$39,794	$36,894	$129,186		$3,063,507	$5,308
Meter Expenses	$735,875	$449,570	$163,298	$28,504	$4,145	$32,821		$4,259	$42,623	$10,656	$448,905	$1,329
Distribution Station Expense	$1,860,476	$941,785	$164,675	$305,805	$151,190		$8,923	$21,968	$266,130		$939,107	$2,678
Street Lighting	$70,677						$70,677					
Other Plant	$258,804	$170,911	$26,098	$24,200	$10,440	$517	$5,021	$2,578	$18,871	$168	$170,564	$358
Total Distribution	$10,428,018	$7,365,436	$1,112,503	$769,231	$306,326	$33,338	$159,873	$98,571	$571,917	$10,824	$7,351,710	$14,401
Total Operation & Maintenance	$180,920,032	$83,254,269	$16,594,416	$29,564,857	$14,684,826	$4,504,857	$756,995	$1,736,017	$25,603,026	$4,220,770	$83,082,364	$172,580
Customer Service, Accounts, & Sales												
Supervision & Administration	$1,789,798	$1,434,855	$173,234	$19,375	$88,400	$7,687	$25,763	$17,742	$18,194	$4,549	$1,432,734	$3,740
Meter Reading	$240,095	$188,300	$22,734	$2,543	$15,174	$1,319	$3,626	$2,497	$3,122	$780	$188,021	$557
Customer Billing	$617,387	$484,199	$58,459	$6,538	$39,018	$3,393	$9,324	$6,421	$8,027	$2,007	$483,483	$1,432
Credit & Collections	$1,027,939	$887,665	$107,170	$11,986	$353	$31	$12,210	$8,409	$92	$23	$886,353	$1,312
Customer Assistance	$2,793,832	$2,191,123	$264,540	$29,587	$176,567	$15,354	$42,194	$29,058	$36,326	$9,081	$2,187,885	$6,478
Energy Management Promotion												
Total Customer Service, Accounts & Sales	$6,469,051	$5,186,142	$626,136	$70,030	$319,513	$27,784	$93,117	$64,128	$65,761	$16,440	$5,178,476	$13,518
Total O&M w/o Purchased Power Supply & A&G	$48,785,099	$27,712,280	$4,472,899	$5,754,406	$3,049,625	$872,814	$326,438	$429,946	$5,345,186	$821,506	$27,655,977	$62,830

Fortis BC 2017 COSA

REVENUE REQUIREMENT COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 3.3

2017	Total Expenses	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Administrative & General												
Executive & Senior Management	$544,631	$301,947	$50,920	$69,084	$32,710	$7,630	$9,512	$5,160	$60,759	$6,908	$301,299	$661
Legal	$719,245	$398,755	$67,246	$91,233	$43,197	$10,077	$12,562	$6,815	$80,239	$9,123	$397,899	$872
Human Resources	$622,584	$345,165	$58,208	$78,972	$37,391	$8,722	$10,874	$5,899	$69,455	$7,897	$344,424	$755
Regulatory & Finance	$1,271,152	$704,736	$118,846	$161,239	$76,344	$17,809	$22,201	$12,044	$141,809	$16,123	$703,223	$1,542
Information Services	$1,263,876	$700,703	$118,166	$160,317	$75,907	$17,707	$22,074	$11,975	$140,998	$16,031	$699,198	$1,533
Materials Management	-$10,394	-$5,762	-$972	-$1,318	-$624	-$146	-$182	-$98	-$1,160	-$132	-$5,750	-$13
Other	$320,127	$177,481	$29,930	$40,606	$19,226	$4,485	$5,591	$3,033	$35,713	$4,061	$177,099	$388
Executive & Senior Management Expenses	$46,772	$25,931	$4,373	$5,933	$2,809	$655	$817	$443	$5,218	$593	$25,875	$57
Legal Expenses	$236,977	$131,382	$22,156	$30,059	$14,232	$3,320	$4,139	$2,245	$26,437	$3,006	$131,100	$287
Human Resources Expenses	$101,858	$56,471	$9,523	$12,920	$6,117	$1,427	$1,779	$965	$11,363	$1,292	$56,350	$124
Regulatory & Finance Expenses	$147,591	$81,825	$13,799	$18,721	$8,864	$2,068	$2,578	$1,398	$16,465	$1,872	$81,650	$179
Information Services Expenses	$1,587,121	$879,912	$148,387	$201,319	$95,320	$22,235	$27,720	$15,038	$177,059	$20,131	$878,022	$1,925
Materials Management	$356,505	$197,649	$33,331	$45,221	$21,411	$4,995	$6,226	$3,378	$39,772	$4,522	$197,224	$432
Other Expenses	$188,126	$104,299	$17,589	$23,863	$11,299	$2,636	$3,286	$1,783	$20,987	$2,386	$104,075	$228
Other Items	$5,603,254	$3,128,059	$527,225	$713,953	$337,923	$78,576	$65,366	$53,423	$627,633	$71,097	$3,121,344	$6,842
Total Administrative & General	$12,999,425	$7,228,552	$1,218,727	$1,652,122	$782,126	$182,195	$194,543	$123,503	$1,452,747	$164,911	$7,213,032	$15,814
Total O&M plus A&G	$200,388,508	$95,668,963	$18,439,279	$31,287,009	$15,786,465	$4,714,836	$1,044,654	$1,923,647	$27,121,533	$4,402,121	$95,473,872	$201,912
Depreciation												
Generation Plant	$4,507,000	$1,969,465	$414,078	$771,807	$389,205	$121,428	$17,256	$50,791	$665,466	$107,504	$1,965,254	$4,212
Transmission Plant	$10,447,000	$5,263,931	$848,442	$1,478,120	$714,149	$254,431	$12,280	$65,243	$1,542,054	$268,351	$5,251,256	$12,675
Distribution Plant	$27,685,000	$18,282,878	$2,791,779	$2,588,698	$1,116,784	$55,319	$537,132	$275,751	$2,018,699	$17,960	$18,245,744	$38,255
General Plant And Deferred Charges	$13,407,000	$7,882,500	$1,266,163	$1,568,882	$726,092	$152,366	$166,739	$122,975	$1,380,886	$140,397	$7,865,735	$17,089
Amortization	-$389,000	-$178,014	-$35,961	-$63,882	-$31,965	-$9,660	-$1,586	-$4,297	-$55,079	-$8,556	-$177,635	-$381
Total Depreciation	$55,657,000	$33,220,760	$5,284,502	$6,343,625	$2,914,265	$573,885	$731,820	$510,461	$5,552,026	$525,656	$33,150,353	$71,850
Taxes												
Property	$16,052,000	$9,416,218	$1,517,360	$1,885,788	$874,158	$185,506	$197,706	$147,930	$1,657,025	$170,309	$9,396,230	$20,374
Total Property Taxes	$16,052,000	$9,416,218	$1,517,360	$1,885,788	$874,158	$185,506	$197,706	$147,930	$1,657,025	$170,309	$9,396,230	$20,374
Return and Income Taxes												
Incentive Adjustments												
Income Tax	$10,849,000	$6,195,707	$1,020,230	$1,328,635	$622,495	$138,542	$135,067	$99,813	$1,181,391	$127,119	$6,182,346	$13,642
Return on Rate Base	$87,237,000	$49,819,788	$8,203,689	$10,683,580	$5,005,497	$1,114,022	$1,086,078	$802,597	$9,499,582	$1,022,167	$49,712,353	$109,699
Interest on Non Rate Base Deferral Account												
Total Return and Income Taxes	$98,086,000	$56,015,494	$9,223,919	$12,012,215	$5,627,992	$1,252,565	$1,221,145	$902,410	$10,680,973	$1,149,286	$55,894,699	$123,341
Revenue Requirement Before Other Revenues	$370,183,508	$194,321,435	$34,465,061	$51,528,637	$25,202,880	$6,726,792	$3,195,326	$3,484,448	$45,011,557	$6,247,372	$193,915,154	$417,477

Fortis BC 2017 COSA

REVENUE REQUIREMENT COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 3.3

	2017 **Total Expenses**	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Revenue Req. Before Taxes and Other Revenues	$354,131,508	$184,905,218	$32,947,700	$49,642,849	$24,328,722	$6,541,286	$2,997,620	$3,336,518	$43,354,532	$6,077,063	$184,518,924	$397,104
Other Revenues												
Electric Apparatus Rental	$4,576,000	$3,539,676	$462,610	$250,523	$85,730		$45,900	$42,555	$149,007		$3,533,554	$6,122
Rate 37 Revenue	$1,448,608	$827,279	$136,226	$177,405	$83,118	$18,499	$18,035	$13,327	$157,745	$16,974	$825,495	$1,822
Contract Revenue	$1,865,000	$814,966	$171,346	$319,374	$161,053	$50,247	$7,141	$21,017	$275,370	$44,485	$813,223	$1,743
Transmission Access Revenue	$1,179,000	$594,063	$95,751	$166,814	$80,596	$28,714	$1,386	$7,363	$174,029	$30,285	$592,632	$1,430
Fortis Pacific Holdings												
Connection Charges	$270,000	$233,155	$28,149	$3,148	$93	$8	$3,207	$2,209	$24	$6	$232,811	$345
NSF Cheque Charges												
Sundry Revenue	$142,000	$82,897	$13,316	$16,499	$7,636	$1,602	$2,758	$1,293	$14,522	$1,476	$82,721	$180
Investment Income	$24,000	$14,011	$2,251	$2,789	$1,291	$271	$466	$219	$2,454	$250	$13,981	$30
Total Other Revenues	$9,504,608	$6,106,047	$909,649	$936,552	$419,517	$99,341	$78,892	$87,983	$773,152	$93,476	$6,094,417	$11,672
REVENUE REQUIREMENT for COST ALLOCA	$360,678,900	$188,215,388	$33,555,412	$50,592,085	$24,783,364	$6,627,451	$3,116,434	$3,396,465	$44,238,404	$6,153,896	$187,820,737	$405,806

Fortis BC 2017 COSA

REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.4

2017	Total Expenses	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Operation & Maintenance Expense												
Op. Supervision & Engineering												
Water for Power												
Hydraulic Expenses												
Electric Expenses												
Misc. Hydraulic Power Generation												
Rents												
Op. Supplies												
Maint. Supervision & Engineering												
Structures												
Dams & Waterways												
Electric Plant												
Other Plant												
Maint. of Hydraulic Production Plant												
Other Power Generation												
Op. Supervision & Engineering												
Fuel												
Generation												
Misc. Other Power Generation												
Rents												
Op. Supplies												
Maint. Supervision & Engineering												
Maint. of Structures												
Maint. of Generating and Electric Plant												
Maint. Misc. Other Generation Plant												
Maint. of Other Production Plant												
Purchased Power Supply/Other												
Purchased Power - Energy Charges												
Purchased Power - Demand Charges												
System Control												
Base Power Supply												
Irrigation On-Peak Credit												
Irrigation Off-Peak Credit												
Total Purchased Power												
Total Production												
Transmission												
Op. Supervision & Engineering												

Fortis BC 2017 COSA

REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.4

	2017 **Total Expenses**	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
System Planning												
Load Dispatching												
Transmission Station Expense												
Transmission Line Maintenance												
Transmission TROW Maintenance												
Wheeling												
Rents												
Op. Supplies												
Maint. Supervision & Engineering												
Maint. of Structures												
Maint. of Station Equipment												
Maint. of Overhead Lines												
Maint. Of Underground Lines												
Maint. of Misc. Transmission Plant												
Maint. Of Transmission Plant												
Total Transmission												
Distribution												
Distribution Line Maintenance												
Distribution ROW Maintenance												
Meter Expenses												
Distribution Station Expense												
Street Lighting	$70,677						$70,677					
Other Plant	$3,064						$3,064					
Total Distribution	$73,741						$73,741					
Total Operation & Maintenance	$73,741						$73,741					
Customer Service, Accounts, & Sales												
Supervision & Administration												
Meter Reading												
Customer Billing												
Credit & Collections												
Customer Assistance												
Energy Management Promotion												
Total Customer Service, Accounts & Sales												
Total O&M w/o Purchased Power Supply & A&G	$73,741						$73,741					

Fortis BC 2017 COSA

REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.4

	2017 Total Expenses	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Administrative & General												
Executive & Senior Management	$3,225						$3,225					
Legal	$4,259						$4,259					
Human Resources	$3,687						$3,687					
Regulatory & Finance	$7,528						$7,528					
Information Services	$7,485						$7,485					
Materials Management	-$62						-$62					
Other	$1,896						$1,896					
Executive & Senior Management Expenses	$277						$277					
Legal Expenses	$1,403						$1,403					
Human Resources Expenses	$603						$603					
Regulatory & Finance Expenses	$874						$874					
Information Services Expenses	$9,399						$9,399					
Materials Management	$2,111						$2,111					
Other Expenses	$1,114						$1,114					
Other Items	$33,183	$21,573	$3,351	$3,208	$1,399	$75	$686	$332	$2,536	$24	$21,529	$46
Total Administrative & General	$76,984	$21,573	$3,351	$3,208	$1,399	$75	$44,486	$332	$2,536	$24	$21,529	$46
Total O&M plus A&G	$150,725	$21,573	$3,351	$3,208	$1,399	$75	$118,228	$332	$2,536	$24	$21,529	$46
Depreciation												
Generation Plant												
Transmission Plant												
Distribution Plant	$327,763						$327,763					
General Plant And Deferred Charges	$94,814						$94,814					
Amortization												
Total Depreciation	$422,578						$422,578					
Taxes												
Property	$111,433						$111,433					
Total Property Taxes	$111,433						$111,433					
Return and Income Taxes												
Incentive Adjustments												
Income Tax	$80,802	$3	$0	$0	$0	$0	$80,798	$0	$0	$0	$3	$0
Return on Rate Base	$649,734	$23	$4	$3	$2	$0	$649,698	$0	$3	$0	$23	$0
Interest on Non Rate Base Deferral Account												
Total Return and Income Taxes	$730,536	$26	$4	$4	$2	$0	$730,496	$0	$3	$0	$26	$0
Revenue Requirement Before Other Revenues	$1,415,272	$21,599	$3,355	$3,212	$1,401	$75	$1,382,735	$332	$2,539	$24	$21,555	$46

Fortis BC 2017 COSA

REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.4

	2017 Total Expenses	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Revenue Req. Before Taxes and Other Revenues	$1,303,838	$21,599	$3,355	$3,212	$1,401	$75	$1,271,301	$332	$2,539	$24	$21,555	$46
Other Revenues												
Electric Apparatus Rental												
Rate 37 Revenue	$10,789	$6,162	$1,015	$1,321	$619	$138	$134	$99	$1,175	$126	$6,148	$14
Contract Revenue												
Transmission Access Revenue												
Fortis Pacific Holdings												
Connection Charges												
NSF Cheque Charges												
Sundry Revenue	$1,004						$1,004					
Investment Income	$170						$170					
Total Other Revenues	$11,963	$6,162	$1,015	$1,321	$619	$138	$1,308	$99	$1,175	$126	$6,148	$14
REVENUE REQUIREMENT for COST ALLOCATION	$1,403,309	$15,438	$2,340	$1,890	$782	-$63	$1,381,426	$233	$1,364	-$102	$15,407	$32

Fortis BC 2017 COSA

INPUT RATE BASE
Schedule 4.1

Source: Schedule 6 Oct 5, 2016 Evidentiary Update for 2017

FERC Account		2016 Cost, $	2017 Cost, $	Mid-year Cost, $	Function	Classification Factor	Classification Method
	Hydraulic Production						
330.00	Land & Rights	$962,000	$962,000	$962,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
331.00	Structures & Improvements	$15,562,000	$15,896,000	$15,729,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
332.00	Reservoirs, Dams, & Waterways	$33,955,000	$34,765,000	$34,360,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
333.00	Water Wheels, Turbines, & Generators	$96,860,000	$96,903,000	$96,881,500	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
334.00	Accessory Electric Equipment	$43,059,000	$43,057,000	$43,058,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
335.00	Misc. Power Plant Equipment	$45,982,000	$46,390,000	$46,186,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
336.00	Roads, RR, & Bridges	$1,287,000	$1,287,000	$1,287,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
	Total Hydraulic Production	$237,667,000	$239,260,000	$238,463,500			
	Total Production Plant	$237,667,000	$239,260,000	$238,463,500	12%		
	Transmission Plant						
350.10	Land & Rights - R/W	$9,206,000	$9,405,000	$9,305,500	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
350.10	Land & Rights - Clearing	$8,436,000	$8,635,000	$8,535,500	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
353.00	Station Equipment	$201,432,000	$214,567,000	$207,999,500	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
355.00	Poles Towers & Fixtures	$108,934,000	$112,228,000	$110,581,000	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
356.00	Conductors & Devices	$103,960,000	$106,627,000	$105,293,500	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
359.00	Roads, Railroads & Bridges	$1,121,000	$1,121,000	$1,121,000	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
	Total Transmission Plant	$433,089,000	$452,583,000	$442,836,000	23%		
	Distribution Plant						
360.10	Land & Rights - R/W	$4,576,000	$4,576,000	$4,576,000	D	NCPP	Non-Coincident Peak - Primary
360.10	Land & Rights - Clearing	$10,456,000	$10,456,000	$10,456,000	D	NCPP	Non-Coincident Peak - Primary
362.00	Station Equipment	$272,296,000	$271,956,000	$272,126,000	D	NCPP	Non-Coincident Peak - Primary
364.00	Poles, Towers, & Fixtures	$218,057,000	$236,568,000	$227,312,500	D	MINSYSP	Minimum System - Poles, Towers & Fixtures (96% Customer, 4% Demand)
365.00	Conductors & Devices	$299,545,000	$304,644,000	$302,094,500	D	MINSYSC	Minimum System - Overhead and Underground Conduit (58% Customer, 42% Demand)
368.00	Line Transformers	$136,134,000	$137,693,000	$136,913,500	D	MINSYST	Minimum System - Transformers (73% Customer, 27% Demand)
369.00	Services	$9,521,000	$9,521,000	$9,521,000	D	CUSTM	Customers Weighted for Meters and Services
370.00	Meters/AMI Meters	$34,080,000	$35,564,000	$34,822,000	D	CUSTM	Customers Weighted for Meters and Services
371.00	Installation on Customer Premises	$938,000	$938,000	$938,000	D	CUSTM	Customers Weighted for Meters and Services
373.00	Street Lights and Signal Systems	$12,001,000	$11,931,000	$11,966,000	D	DA1	Direct Assignment for Streetlights
	Total Distribution Plant	$997,604,000	$1,023,847,000	$1,010,725,500	52%		
	Total Transmission & Distribution	$1,430,693,000	$1,476,430,000	$1,453,561,500			

Fortis BC 2017 COSA

INPUT RATE BASE
Schedule 4.1

Source: Schedule 6 Oct 5, 2016 Evidentiary Update for 2017

FERC Account		2016 Cost, $	2017 Cost, $	Mid-year Cost, $	Function	Classification Factor	Classification Method
	General Plant						
389.00	Land & Rights	$12,354,000	$12,354,000	$12,354,000	SS	LABOR	On the Basis of Labor Ratios
390.00	Structures - Frame & Iron	$337,000	$337,000	$337,000	SS	LABOR	On the Basis of Labor Ratios
390.10	Structures - Masonry	$45,170,000	$45,893,000	$45,531,500	SS	LABOR	On the Basis of Labor Ratios
391.00	Office Furniture & Equipment	$6,900,000	$7,059,000	$6,979,500	SS	LABOR	On the Basis of Labor Ratios
391.10	Computer Equipment	$97,537,000	$103,411,000	$100,474,000	SS	LABOR	On the Basis of Labor Ratios
391.20	AMI Software	$8,391,000	$8,917,000	$8,654,000	SS	CUSTM	Customers Weighted for Meters and Services
392.00	Transportation Equipment	$26,087,000	$26,899,000	$26,493,000	SS	LABOR	On the Basis of Labor Ratios
394.00	Tool and Work Environment	$14,262,000	$14,930,000	$14,596,000	SS	LABOR	On the Basis of Labor Ratios
397.00	Communication Structures & Equipment	$29,335,000	$29,581,000	$29,458,000	SS	LABOR	On the Basis of Labor Ratios
397.10	AMI Communications & Equipment	$3,908,000	$8,678,000	$6,293,000	SS	CUSTM	Customers Weighted for Meters and Services
	Total General Plant	$244,281,000	$258,059,000	$251,170,000	13%		
	Total Plant Before General Plant & Intangible	$1,668,360,000	$1,715,690,000	$1,692,025,000			
	Total Gross Plant in Service	$1,912,641,000	$1,973,749,000	$1,943,195,000			
	Less: Accumulated Depreciation						
Not updated yet	Hydraulic Production Plant	$50,973,000	$54,823,000	$52,898,000	P		On the Basis of Hydraulic Production Plant
Not updated yet	Transmission Plant	$113,643,000	$122,436,000	$118,039,500	T	RBT	On the Basis of Transmission Rate Base
Not updated yet	Distribution Plant	$246,470,000	$270,180,000	$258,325,000	D	RBD	On the Basis of Distribution Rate Base
Not updated yet	General Plant	$142,035,000	$153,987,000	$148,011,000	SS	RBGP	On the Basis of General Plant Rate Base
Not updated yet	CWIP				SS		On the Basis of CWIP
Not updated yet	**Total Accumulated Depreciation**	$553,121,000	$601,426,000	$577,273,500			
Not updated yet	**Total Net Plant**	$1,359,520,000	$1,372,323,000	$1,365,921,500			
Not updated yet	**Working Capital**						
Not updated yet	Allowance for Working Capital	$2,009,000	$2,906,000	$2,906,000	SS	OM	On the Basis of All O&M
Not updated yet	Adjustment for Capital Additions		$2,987,000	$2,987,000	SS	OM	On the Basis of All O&M
Not updated yet	**Total Working Capital**	$2,009,000	$5,893,000	$5,893,000			
Not updated yet	Distribution Plant CIAC	-$111,698,000	-$114,036,000	-$112,867,000	D		On the Basis of Poles, Conductors and Transformers
Not updated yet	**Total Contributions**	-$111,698,000	-$114,036,000	-$112,867,000			
Not updated yet	***SUB-TOTAL RATE BASE***	$1,249,831,000	$1,264,180,000	$1,258,947,500			
Not updated yet	**Other Rate Base Items**						
Not updated yet	Production Plant CWIP not subject to AFUDC				P	RBG	On the Basis of Generation Rate Base
Not updated yet	Transmission Plant CWIP not subject to AFUDC				T	RBT	On the Basis of Transmission Rate Base
Not updated yet	Distribution Plant CWIP not subject to AFUDC				D	RBD	On the Basis of Distribution Rate Base
Not updated yet	General Plant CWIP not subject to AFUDC	$6,532,000	$8,387,000	$7,459,500	D	RBGP	On the Basis of General Plant Rate Base
Not updated yet	Deferred DSM	$12,296,000	$12,392,000	$12,344,000	SS	DSM	Classified 72% Energy, 17% Demand & 12% T&D
Not updated yet	Plant Acquisition Adjustment & Deferred	$5,865,000	$5,679,000	$5,772,000	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
Not updated yet	Total Other Rate Base Items	$24,693,000	$26,458,000	$25,575,500			
	TOTAL RATE BASE	$1,274,524,000	$1,290,638,000	$1,284,523,000			

Fortis BC 2017 COSA

RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2

		Production			Transmission			Distribution			
Account Description	Total Rate Base	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
Hydraulic Production											
Land & Rights	$962,000	$190,774	$771,226								
Structures & Improvements	$15,729,000	$3,119,207	$12,609,793								
Reservoirs, Dams, & Waterways	$34,360,000	$6,813,909	$27,546,091								
Water Wheels, Turbines, & Generators	$96,881,500	$19,212,505	$77,668,995								
Accessory Electric Equipment	$43,058,000	$8,538,803	$34,519,197								
Misc. Power Plant Equipment	$46,186,000	$9,159,115	$37,026,885								
Roads, RR, & Bridges	$1,287,000	$255,224	$1,031,776								
Total Hydraulic Production	$238,463,500	$47,289,537	$191,173,963								
Total Production Plant	$238,463,500	$47,289,537	$191,173,963								
Transmission Plant											
Land & Rights - R/W	$9,305,500				$9,305,500						
Land & Rights - Clearing	$8,535,500				$8,535,500						
Station Equipment	$207,999,500				$207,999,500						
Poles Towers & Fixtures	$110,581,000				$110,581,000						
Conductors & Devices	$105,293,500				$105,293,500						
Roads, Railroads & Bridges	$1,121,000				$1,121,000						
Total Transmission Plant	$442,836,000				$442,836,000						
Distribution Plant											
Land & Rights - R/W	$4,576,000							$4,576,000			
Land & Rights - Clearing	$10,456,000							$10,456,000			
Station Equipment	$272,126,000							$272,126,000			
Poles, Towers, & Fixtures	$227,312,500							$43,189,375		$184,123,125	
Conductors & Devices	$302,094,500							$105,733,075		$196,361,425	
Line Transformers	$136,913,500							$42,443,185		$94,470,315	
Services	$9,521,000									$9,521,000	
Meters/AMI Meters	$34,822,000									$34,822,000	
Installation on Customer Premises	$938,000									$938,000	
Street Lights and Signal Systems	$11,966,000										$11,966,000
Total Distribution Plant	$1,010,725,500							$478,523,635		$520,235,865	$11,966,000
Total Transmission & Distribution	$1,453,561,500				$442,836,000			$478,523,635		$520,235,865	$11,966,000

Fortis BC 2017 COSA

RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2

Account Description	Total Rate Base	Production Demand PD	Production Energy PE	Production Direct Assignment PDA	Transmission Demand TD	Transmission Energy TE	Transmission Direct Assignment TDA	Distribution Demand DD	Distribution Energy DE	Distribution Customer DC	Distribution Direct Assignment DDA
General Plant											
Land & Rights	$12,354,000	$687,492	$2,779,274		$2,707,548			$2,925,746		$3,180,779	$73,161
Structures - Frame & Iron	$337,000	$18,754	$75,815		$73,858			$79,810		$86,767	$1,996
Structures - Masonry	$45,531,500	$2,533,798	$10,243,200		$9,978,850			$10,783,034		$11,722,976	$269,641
Office Furniture & Equipment	$6,979,500	$388,405	$1,570,175		$1,529,653			$1,652,926		$1,797,009	$41,333
Computer Equipment	$100,474,000	$5,591,312	$22,603,589		$22,020,250			$23,794,836		$25,868,998	$595,016
AMI Software	$8,654,000									$8,654,000	
Transportation Equipment	$26,493,000	$1,474,318	$5,960,118		$5,806,303			$6,274,226		$6,821,141	$156,894
Tool and Work Environment	$14,596,000	$812,258	$3,283,655		$3,198,913			$3,456,709		$3,758,026	$86,439
Communication Structures & Equipment	$29,458,000	$1,639,318	$6,627,152		$6,456,123			$6,976,415		$7,584,539	$174,453
AMI Communications & Equipment	$6,293,000									$6,293,000	
Total General Plant	$251,170,000	$13,145,654	$53,142,978		$51,771,498			$55,943,702		$75,767,236	$1,398,933
Total Plant Before General Plant & Intangible	$1,692,025,000	$47,289,537	$191,173,963		$442,836,000			$478,523,635		$520,235,865	$11,966,000
Total Gross Plant in Service	$1,943,195,000	$60,435,191	$244,316,941		$494,607,498			$534,467,337		$596,003,101	$13,364,933
Less: Accumulated Depreciation											
Hydraulic Production Plant	$52,898,000	$10,490,167	$42,407,833								
Transmission Plant	$118,039,500				$118,039,500						
Distribution Plant	$258,325,000							$122,302,859		$132,963,826	$3,058,315
General Plant	$148,011,000	$7,746,552	$31,316,420		$30,508,226			$32,966,848		$44,648,582	$824,372
CWIP											
Total Accumulated Depreciation	$577,273,500	$18,236,719	$73,724,253		$148,547,726			$155,269,707		$177,612,408	$3,882,687
Total Net Plant	$1,365,921,500	$42,198,472	$170,592,688		$346,059,772			$379,197,630		$418,390,692	$9,482,246
Working Capital											
Allowance for Working Capital	$2,906,000	$662,818	$1,781,216		$294,467			$54,747		$111,567	$1,184
Adjustment for Capital Additions	$2,987,000	$681,293	$1,830,865		$302,675			$56,273		$114,676	$1,217
Total Working Capital	$5,893,000	$1,344,111	$3,612,081		$597,143			$111,020		$226,243	$2,402
Distribution Plant CIAC	-$112,867,000							-$32,415,129		-$80,451,871	
Total Contributions	-$112,867,000							-$32,415,129		-$80,451,871	
SUB-TOTAL RATE BASE	$1,258,947,500	$43,542,583	$174,204,768		$346,656,914			$346,893,521		$338,165,065	$9,484,648
Other Rate Base Items											
Production Plant CWIP not subject to AFUDC											
Transmission Plant CWIP not subject to AFUDC											
Distribution Plant CWIP not subject to AFUDC											
General Plant CWIP not subject to AFUDC	$7,459,500	$390,413	$1,578,294		$1,537,562			$1,661,472		$2,250,212	$41,547
Deferred DSM	$12,344,000	$2,049,104	$8,838,304		$443,759			$485,266		$527,566	
Plant Acquisition Adjustment & Deferred	$5,772,000	$161,319	$652,151		$1,510,645			$1,632,386		$1,774,679	$40,820
Total Other Rate Base Items	$25,575,500	$2,600,836	$11,068,749		$3,491,967			$3,779,125		$4,552,457	$82,366
TOTAL RATE BASE	$1,284,523,000	$46,143,419	$185,273,517		$350,148,881			$350,672,646		$342,717,522	$9,567,014

Fortis BC 2017 COSA

RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

Account Description	Total Rate Base	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Hydraulic Production												
Land & Rights	$962,000	$420,374	$88,383	$164,739	$83,074	$25,918	$3,683	$10,841	$142,041	$22,946	$419,475	$899
Structures & Improvements	$15,729,000	$6,873,247	$1,445,094	$2,693,532	$1,358,287	$423,772	$60,223	$177,254	$2,322,412	$375,179	$6,858,547	$14,699
Reservoirs, Dams, & Waterways	$34,360,000	$15,014,607	$3,156,807	$5,884,021	$2,967,179	$925,729	$131,556	$387,212	$5,073,310	$819,579	$14,982,497	$32,110
Water Wheels, Turbines, & Generators	$96,881,500	$42,335,205	$8,900,937	$16,590,593	$8,366,261	$2,610,186	$370,936	$1,091,784	$14,304,711	$2,310,886	$42,244,667	$90,538
Accessory Electric Equipment	$43,058,000	$18,815,453	$3,955,931	$7,373,521	$3,718,300	$1,160,071	$164,859	$485,232	$6,357,584	$1,027,050	$18,775,214	$40,239
Misc. Power Plant Equipment	$46,186,000	$20,182,324	$4,243,315	$7,909,179	$3,988,420	$1,244,346	$176,835	$520,483	$6,819,438	$1,101,661	$20,139,162	$43,162
Roads, RR, & Bridges	$1,287,000	$562,392	$118,242	$220,394	$111,140	$34,674	$4,928	$14,504	$190,028	$30,698	$561,190	$1,203
Total Hydraulic Production	$238,463,500	$104,203,602	$21,908,710	$40,835,979	$20,592,661	$6,424,696	$913,019	$2,687,310	$35,209,524	$5,688,001	$103,980,752	$222,850
Total Production Plant	$238,463,500	$104,203,602	$21,908,710	$40,835,979	$20,592,661	$6,424,696	$913,019	$2,687,310	$35,209,524	$5,688,001	$103,980,752	$222,850
Transmission Plant												
Land & Rights - R/W	$9,305,500	$4,688,763	$755,737	$1,316,612	$636,117	$226,631	$10,938	$58,114	$1,373,560	$239,029	$4,677,473	$11,290
Land & Rights - Clearing	$8,535,500	$4,300,783	$693,202	$1,207,667	$583,480	$207,878	$10,033	$53,305	$1,259,903	$219,251	$4,290,427	$10,356
Station Equipment	$207,999,500	$104,804,721	$16,892,468	$29,429,330	$14,218,681	$5,065,720	$244,486	$1,298,977	$30,702,256	$5,342,863	$104,552,367	$252,354
Poles Towers & Fixtures	$110,581,000	$55,718,455	$8,980,723	$15,645,829	$7,559,229	$2,693,143	$129,979	$690,589	$16,322,569	$2,840,483	$55,584,294	$134,162
Conductors & Devices	$105,293,500	$53,054,242	$8,551,304	$14,897,714	$7,197,780	$2,564,369	$123,764	$657,568	$15,542,095	$2,704,664	$52,926,496	$127,746
Roads, Railroads & Bridges	$1,121,000	$564,838	$91,041	$158,607	$76,631	$27,301	$1,318	$7,001	$165,468	$28,795	$563,478	$1,360
Total Transmission Plant	$442,836,000	$223,131,802	$35,964,475	$62,655,759	$30,271,917	$10,785,042	$520,517	$2,765,553	$65,365,850	$11,375,085	$222,594,535	$537,267
Distribution Plant												
Land & Rights - R/W	$4,576,000	$2,316,400	$405,032	$752,153	$371,864		$21,947	$54,032	$654,571		$2,309,814	$6,587
Land & Rights - Clearing	$10,456,000	$5,292,894	$925,484	$1,718,644	$849,697		$50,149	$123,461	$1,495,671		$5,277,843	$15,051
Station Equipment	$272,126,000	$137,751,922	$24,086,472	$44,729,117	$22,114,071		$1,305,161	$3,213,179	$38,926,077		$137,360,208	$391,715
Poles, Towers, & Fixtures	$227,312,500	$178,246,685	$23,065,126	$11,290,538	$3,765,983		$2,329,587	$2,083,932	$6,530,649		$177,944,221	$302,465
Conductors & Devices	$302,094,500	$216,667,332	$29,941,026	$24,673,944	$9,132,176		$2,681,124	$3,020,542	$15,978,355		$216,251,630	$415,702
Line Transformers	$136,913,500	$99,533,469	$13,450,985	$9,590,004	$4,282,766		$1,255,663	$1,309,919	$7,490,696		$99,350,157	$183,312
Services	$9,521,000	$5,816,687	$2,112,804	$368,789	$53,631	$424,650		$55,100	$551,471	$137,868	$5,808,089	$17,197
Meters/AMI Meters	$34,822,000	$21,273,886	$7,727,344	$1,348,805	$196,149	$1,553,112		$201,522	$2,016,945	$504,236	$21,242,439	$62,895
Installation on Customer Premises	$938,000	$573,055	$208,151	$36,333	$5,284	$41,836		$5,428	$54,330	$13,583	$572,207	$1,694
Street Lights and Signal Systems	$11,966,000						$11,966,000					
Total Distribution Plant	$1,010,725,500	$667,472,331	$101,922,423	$94,508,327	$40,771,622	$2,019,599	$19,609,630	$10,067,115	$73,698,766	$655,687	$666,116,607	$1,396,617
Total Transmission & Distribution	$1,453,561,500	$890,604,133	$137,886,898	$157,164,087	$71,043,539	$12,804,641	$20,130,147	$12,832,667	$139,064,616	$12,030,771	$888,711,142	$1,933,885

Fortis BC 2017 COSA

RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

Account Description	Total Rate Base	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
General Plant												
Land & Rights	$12,354,000	$6,960,156	$1,161,563	$1,554,589	$733,743	$171,691	$136,351	$117,528	$1,362,130	$156,249	$6,945,342	$15,064
Structures - Frame & Iron	$337,000	$189,863	$31,686	$42,407	$20,015	$4,683	$3,719	$3,206	$37,157	$4,262	$189,459	$411
Structures - Masonry	$45,531,500	$25,652,124	$4,281,018	$5,729,543	$2,704,258	$632,778	$502,532	$433,158	$5,020,222	$575,867	$25,597,527	$55,519
Office Furniture & Equipment	$6,979,500	$3,932,201	$656,235	$878,279	$414,534	$96,998	$77,033	$66,399	$769,547	$88,274	$3,923,832	$8,510
Computer Equipment	$100,474,000	$56,606,339	$9,446,889	$12,643,337	$5,967,465	$1,396,346	$1,108,933	$955,847	$11,078,083	$1,270,761	$56,485,860	$122,512
AMI Software	$8,654,000	$7,017,583	$981,061	$245,478	$62,550	$33,596	$88,439	$72,163	$142,223	$10,907	$7,006,649	$11,614
Transportation Equipment	$26,493,000	$14,925,968	$2,490,957	$3,333,797	$1,573,502	$368,189	$292,404	$252,038	$2,921,071	$335,074	$14,894,200	$32,304
Tool and Work Environment	$14,596,000	$8,223,283	$1,372,363	$1,836,715	$866,902	$202,849	$161,096	$138,857	$1,609,329	$184,605	$8,205,781	$17,798
Communication Structures & Equipment	$29,458,000	$16,596,428	$2,769,736	$3,706,903	$1,749,603	$409,395	$325,129	$280,245	$3,247,986	$372,575	$16,561,105	$35,919
AMI Communications & Equipment	$6,293,000	$5,103,033	$713,406	$178,506	$45,485	$24,430	$64,311	$52,475	$103,422	$7,931	$5,095,082	$8,446
Total General Plant	$251,170,000	$145,206,979	$23,904,916	$30,149,554	$14,138,057	$3,340,954	$2,759,949	$2,371,916	$26,291,169	$3,006,507	$144,904,838	$308,097
Total Plant Before General Plant & Intangible	$1,692,025,000	$994,807,735	$159,795,608	$198,000,065	$91,636,200	$19,229,336	$21,043,166	$15,519,977	$174,274,140	$17,718,772	$992,691,893	$2,156,735
Total Gross Plant in Service	$1,943,195,000	$1,140,014,714	$183,700,524	$228,149,619	$105,774,257	$22,570,291	$23,803,115	$17,891,893	$200,565,309	$20,725,279	$1,137,596,731	$2,464,832
Less: Accumulated Depreciation												
Hydraulic Production Plant	$52,898,000	$23,115,328	$4,859,976	$9,058,584	$4,568,039	$1,425,181	$202,534	$596,122	$7,810,476	$1,261,761	$23,065,894	$49,435
Transmission Plant	$118,039,500	$59,476,570	$9,586,458	$16,701,114	$8,069,086	$2,874,791	$138,746	$737,168	$17,423,498	$3,032,069	$59,333,359	$143,210
Distribution Plant	$258,325,000	$170,595,073	$26,049,714	$24,154,791	$10,420,564	$516,177	$5,011,903	$2,572,991	$18,836,206	$167,583	$170,248,571	$356,953
General Plant	$148,011,000	$85,568,460	$14,086,835	$17,766,714	$8,331,361	$1,968,778	$1,626,399	$1,397,737	$15,493,022	$1,771,693	$85,390,413	$181,557
CWIP												
Total Accumulated Depreciation	$577,273,500	$338,755,431	$54,582,983	$67,681,203	$31,389,050	$6,784,926	$6,979,581	$5,304,018	$59,563,202	$6,233,105	$338,038,237	$731,155
Total Net Plant	$1,365,921,500	$801,259,283	$129,117,541	$160,468,416	$74,385,207	$15,785,364	$16,823,534	$12,587,875	$141,002,107	$14,492,174	$799,558,493	$1,733,677
Working Capital												
Allowance for Working Capital	$2,906,000	$1,337,332	$265,659	$473,694	$237,571	$72,353	$12,733	$27,987	$410,861	$67,808	$1,334,573	$2,805
Adjustment for Capital Additions	$2,987,000	$1,374,608	$273,064	$486,898	$244,193	$74,370	$13,088	$28,767	$422,314	$69,698	$1,371,772	$2,883
Total Working Capital	$5,893,000	$2,711,940	$538,724	$960,592	$481,764	$146,722	$25,822	$56,754	$833,175	$137,506	$2,706,344	$5,689
Distribution Plant CIAC	-$112,867,000	-$83,753,696	-$11,257,072	-$7,716,404	-$2,910,250		-$1,061,451	-$1,086,524	-$5,081,603		-$83,600,996	-$152,700
Total Contributions	-$112,867,000	-$83,753,696	-$11,257,072	-$7,716,404	-$2,910,250		-$1,061,451	-$1,086,524	-$5,081,603		-$83,600,996	-$152,700
SUB-TOTAL RATE BASE	$1,258,947,500	$720,217,528	$118,399,193	$153,712,604	$71,956,721	$15,932,087	$15,787,904	$11,558,105	$136,753,679	$14,629,680	$718,663,842	$1,586,666
Other Rate Base Items												
Production Plant CWIP not subject to AFUDC												
Transmission Plant CWIP not subject to AFUDC												
Distribution Plant CWIP not subject to AFUDC												
General Plant CWIP not subject to AFUDC	$7,459,500	$4,312,503	$709,952	$895,412	$419,886	$99,223	$81,968	$70,444	$780,822	$89,290	$4,303,530	$9,150
Deferred DSM	$12,344,000	$5,648,870	$1,141,135	$2,027,136	$1,014,339	$306,540	$50,322	$136,363	$1,747,789	$271,506	$5,636,821	$12,091
Plant Acquisition Adjustment & Deferred	$5,772,000	$3,393,585	$545,110	$675,437	$312,598	$65,597	$71,784	$52,943	$594,501	$60,444	$3,386,367	$7,357
Total Other Rate Base Items	$25,575,500	$13,354,958	$2,396,198	$3,597,985	$1,746,823	$471,360	$204,074	$259,749	$3,123,111	$421,241	$13,326,718	$28,598
TOTAL RATE BASE	$1,284,523,000	$733,572,486	$120,795,391	$157,310,589	$73,703,544	$16,403,447	$15,991,978	$11,817,855	$139,876,791	$15,050,920	$731,990,560	$1,615,264

Fortis BC 2017 COSA

ANALYSIS OF FORECAST POWER PURCHASE EXPENSE
FOR THE YEAR ENDING DECEMBER 31
Schedule 5.1

Purchased Power Supply Summary	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	Totals
Energy Charges	$11,532,591	$9,720,652	$8,267,124	$6,802,573	$7,316,779	$7,164,616	$6,949,696	$8,127,431	$6,305,910	$6,769,494	$9,682,277	$11,387,639	$100,026,782
Total System kWh	343,452,641	296,392,122	280,614,859	242,444,848	243,102,548	251,863,157	269,184,504	292,101,322	238,658,438	256,607,704	282,469,479	390,351,264	3,387,242,885
	$0.0336	$0.0328	$0.0295	$0.0281	$0.0301	$0.0284	$0.0258	$0.0278	$0.0264	$0.0264	$0.0343	$0.0292	$0.0295
Capacity Charges	$4,141,838	$4,287,629	$5,139,980	$524,726	-$930,877	-$120,584	$3,048,894	$3,451,876	$4,356,521	$3,003,686	$4,193,552	$5,091,486	$36,188,726
Total System CP kW	626,318	582,672	513,773	438,566	411,628	593,719	578,916	589,611	416,080	459,584	531,003	711,447	6,453,317
	$6.61	$7.36	$10.00	$1.20	-$2.26	-$0.20	$5.27	$5.85	$10.47	$6.54	$7.90	$7.16	$5.61

Total Annual		Net Cost	
Combined Costs	$136,215,508	$136,215,508	
Energy %	100,026,782	$100,026,782	73%
Demand %	36,188,726	$36,188,726	27%

Fortis BC 2017 COSA

POWER SUPPLY CALCULATIONS IF PURCHASED AT BC HDYRO 3808 RATES
USED FOR CLASSIFICATION OF HYDRO PLANT
Schedule 5.3

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL	
Energy Amount (GWh)														
Brilliant/Waneta	94	87	66	92	92	85	92	99	68	65	75	80	996	
FortisBC	142	127	142	139	116	114	164	135	122	128	113	151	1,593	
Demand Amount (MW)														
Brilliant/Waneta	290	255	232	155	110	103	227	267	235	169	270	341	2,653	
FortisBC	205	197	192	192	183	171	185	198	193	197	188	208	2,310	
Total System Demand (MW)	482	473	423	415	397	468	444	433	428	432	465	486	5,348	
System	683	631	578	501	449	500	599	572	466	521	649	741	6,890	
% of Total	71%	75%	73%	83%	89%	94%	74%	76%	92%	83%	72%	66%	**77.6%**	
Total System Energy (GWh)	324	265	266	263	251	247	292	286	239	231	265	333	3,260	
System	382	329	317	268	255	251	296	291	245	270	314	388	3,605	
% of Total	85%	81%	84%	98%	99%	98%	99%	98%	98%	85%	84%	86%	90%	
Purchased Power Expense ($000)														
Brilliant/Waneta	$8,747	$8,020	$6,965	$5,063	$4,431	$3,843	$6,008	$8,702	$7,856	$5,733	$8,024	$7,593	$80,983	
Energy Costs if Using 3808 ($000)														
Brilliant/Waneta	$4,435	$4,080	$3,101	$4,493	$4,490	$4,112	$4,484	$4,822	$3,313	$3,153	$3,629	$3,911	$48,023	
FortisBC	$6,662	$5,966	$6,670	$6,775	$5,628	$5,536	$7,984	$6,581	$5,932	$6,212	$5,494	$7,366	$76,807	
Demand Costs if Using 3808 ($000)														
Brilliant/Waneta	$2,321	$2,044	$1,858	$1,286	$916	$852	$1,887	$2,216	$1,948	$1,404	$2,237	$2,825	$21,795	
FortisBC	$1,645	$1,580	$1,543	$1,594	$1,518	$1,419	$1,531	$1,645	$1,603	$1,631	$1,563	$1,727	$18,999	
Combined Costs if Using 3808 ($000)	$8,306	$7,546	$8,213	$8,369	$7,147	$6,956	$9,515	$8,226	$7,535	$7,843	$7,058	$9,094	$95,807	

Resulting Classification Factor	
Energy Component	80.2%
Demand Component	19.8%

Adjustment Factor Calculation	Combined 3808 Cost	Actual Cost vs 3808 Cost
Brilliant/Waneta	$69,818	116%

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL	
Adjusted Energy Costs if Using 3808 ($000)														
Brilliant/Waneta	$5,145	$4,732	$3,597	$5,212	$5,208	$4,769	$5,201	$5,594	$3,843	$3,657	$4,210	$4,536	$55,703	
Adjusted Demand Costs if Using 3808 ($000)														
Brilliant/Waneta	$2,692	$2,371	$2,155	$1,491	$1,063	$989	$2,189	$2,570	$2,259	$1,629	$2,594	$3,277	$25,280	$80,983 31%

Analysis of Forecast Power Purchase Expense for Year Ending December 31, 2017

POWER SUPPLY CALCULATIONS IF PURCHASED AT BC HDYRO 3808 RATES
USED FOR CLASSIFICATION OF HYDRO PLANT
Schedule 5.3

2017	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast		
Energy (GWh)														
FortisBC Resources	142	127	142	139	116	114	164	135	122	128	113	151	**1,593**	182
Brilliant Base Plant	82	63	58	81	78	71	78	86	66	62	62	65	**852**	97
Brilliant Upgrade	1	-1	0	10	14	13	14	13	1	1	0	0	**65**	7
Total BCH 3808 Energy	99	75	66	32	43	49	35	52	50	41	90	116	**750**	86
BRX Energy	12	25	9	1	0	0		1	1	2	13	15	**79**	9
Net IPP Generation	0	0	0	0	0	1	1	0	0	0	0	0	**3**	0
Market Energy													-	
Market Capacity - Energy													-	
Market Energy Block Purchase	43	36	39							33	32	34	**217**	25
Market Capacity Block Purchase													-	
Operating Reserve													-	
DSM and Other Customer Savings	2	2	2	2	2	3	3	3	3	3	4	4	**35**	4
DSM and Other Loss Reduction	1	1	1	1	1	1	1	1	1	1	1	1	**11**	1
Loss Recovery													-	
WEPAS Adjustments													-	
FBC Surplus Energy Sales													-	
Total Gross Load (GWh)	**382**	**329**	**317**	**268**	**255**	**251**	**296**	**291**	**245**	**270**	**314**	**388**	**3,605**	3,559
Surplus Energy														
Capacity (MW)													**Total**	**Peak**
FortisBC Resources	205	197	192	192	183	171	185	198	193	197	188	208	**2,310**	**208**
Waneta Expansion	247	246	218	45	13		111	253	257	148	253	218	**2,009**	**257**
Brilliant Base Plant	118	118	110	101	88	96	102	111	115	115	118	118	**1,309**	**118**
Brilliant Upgrade	20	20	20	20	20	20	20	20	20	20	20	20	**238**	**20**
Brilliant Tailrace	4	3	1	3	6	6	6	4	1	1	3	5	**42**	**6**
BCH Billing Capacity	135	135	101	101	101	176	132	132	132	132	135	156	**1,568**	**176**
BCH Peak Usage	135	135	100	100	101	176	132	100	100	100	135	135	**1,449**	**176**
Powerex Capacity Blocks													-	
BRX Capacity	15	38	21	61	34	27	39	50	13	6	16	39	**358**	**61**
Market Purchases - Real Time													-	
Capacity Block Purchases													-	
DSM and Other Customer Savings	3	4	4	4	4	5	5	5	6	6	6	7	**59**	**7**
WAX RCA	-50	-50	-50	-50	-50	-46	-50	-50	-50	-50	-50	-50	**(596)**	**-50**
WAX Firm Energy Sales	-65	-120	-88	-25				-120	-120	-70	-91	-9	**(707)**	**-120**
FBC Peak Load (MW)	**683**	**631**	**578**	**501**	**449**	**500**	**599**	**572**	**466**	**521**	**649**	**741**	**6,890**	**741**
Planning Reserve Margin													-	
Total Capacity Planning Load (MW)	**683**	**631**	**578**	**501**	**449**	**500**	**599**	**572**	**466**	**521**	**649**	**741**	**6,890**	**741**

Energy Rates (CDN$/MWh)													**Average**	
Brilliant Base Plant	43.27	43.27	43.27	43.27	43.27	43.27	43.27	43.27	43.27	43.27	43.27	43.27	**43.27**	
Brilliant Upgrade	30.75	30.75	30.75	30.75	30.75	30.75	30.75	30.75	30.75	30.75	30.75	30.75	**30.75**	
BCH 3808	46.99	46.99	46.99	48.63	48.63	48.63	48.63	48.63	48.63	48.63	48.63	48.63	**48.10**	0
BRX Energy	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	**25.00**	
IPP Rate	59.59	59.59	59.59	59.59	59.59	59.59	59.59	59.59	59.59	59.59	59.59	59.59	**59.59**	
Market Energy	36.90	34.53	28.46	20.01	18.29	15.06	25.88	33.21	32.94	30.77	33.74	37.70	**28.96**	
Market Capacity - Energy	51.50	47.86	40.25	33.44	34.63	34.79	47.70	52.61	47.54	43.26	48.57	54.51	**44.72**	
Market Energy Block Rate	39.35	39.35	39.35	20.01	18.29	15.06	25.88	33.21	32.94	34.49	34.49	34.49	**30.57**	
Market Capacity Block Rate	51.50	47.86	40.25	33.44	34.63	34.79	47.70	52.61	47.54	43.26	48.57	54.51	**44.72**	
Surplus Energy Rate	30.21	28.08	22.61	15.01	13.46	10.55	20.29	26.89	26.65	24.69	27.36	30.93	**23.06**	
Operating Reserve	51.50	47.86	40.25	33.44	34.63	34.79	47.70	52.61	47.54	43.26	48.57	54.51	**44.72**	
Capacity Rates (CDN$/MW/month)														

POWER SUPPLY CALCULATIONS IF PURCHASED AT BC HDYRO 3808 RATES
USED FOR CLASSIFICATION OF HYDRO PLANT
Schedule 5.3

BRD Tailrace Capacity Rate		4,426	4,426	4,426	4,426	4,426	4,426	4,426	4,426	4,426	4,426	4,426	4,426	**4426**	
BCH 3808 Capacity Rate		8,016	8,016	8,016	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	**8227**	0
BRX Capacity		3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	**3400**	
Waneta Expansion		17,349	17,349	17,349	17,349	17,349	17,349	17,349	17,349	17,349	17,349	17,349	17,349	**17349**	
Powerex Capacity Rate		-	-	-	-	-	-	-	-	-	-	-	-		
WAX Sales Rates															
WAX Capacity Block ($/MW/Month)		8,016	8,016	8,016	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	**8226.80**	
Exchange Rate (CDN$/USD$)		1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	**1**	
Energy Expense ($000)															
Brilliant Base Plant		3,546	2,729	2,552	3,541	3,432	3,126	3,433	3,727	2,861	2,695	2,726	2,817	**37,185**	**37,764**
Brilliant Upgrade		22	(20)	(14)	301	427	398	427	392	30	19	9	10	**2,001**	**2,032**
BCH 3808		4,670	3,546	3,125	1,578	2,093	2,366	1,718	2,528	2,446	1,972	4,362	5,656	**36,059**	**36,059**
BRX Energy		295	613	220	35	8	5	-	15	28	55	318	375	**1,965**	**1,965**
IPP Costs		26	26	16	13	16	30	31	5	16	10	6	9	**204**	**204**
Market Energy		-	-	-	-	-	-	-	-	-	-	-	-	**-**	**-**
Market Capacity - Energy		-	-	-	-	-	-	-	-	-	-	-	-	**-**	**-**
Market Energy Block Purchase		1,692.0	1,416.6	1,529.7	-	-	-	-	-	-	1,131.1	1,104.4	1,186.3	**8,060**	**8,060**
Market Capacity Block Purchase		-	-	-	-	-	-	-	-	-	-	-	-	**-**	**-**
Operating Reserve		-	-	-	-	-	-	-	-	-	-	-	-	**-**	**-**
Total Energy Expense ($000)		**10,250**	**8,310**	**7,429**	**5,468**	**5,975**	**5,925**	**5,609**	**6,668**	**5,381**	**5,882**	**8,525**	**10,053**	**85,475**	**86,085**
Capacity Expense ($000)															
Waneta Expansion		5,453	5,445	4,920	1,673	1,075	755	2,910	5,570	5,642	3,606	5,567	4,926	**47,544**	**47,544**
BCH 3808 Capacity		1,082.21	1,082	812	840	840	1,459	1,095	1,094	1,094	1,094	1,120	1,297	**12,909**	**13,672**
BRD Tailrace Capacity		19	13	4	11	27	27	25	16	4	4	15	21	**187**	**187**
BRX Capacity		56	139	75	225	124	100	143	183	48	20	60	142	**1,316**	**1,316**
Total Capacity Expense ($000)		**6,612**	**6,680**	**5,812**	**2,749**	**2,067**	**2,340**	**4,174**	**6,862**	**6,788**	**4,725**	**6,762**	**6,386**	**61,955**	**62,719**
Other Expenses ($000)															
Surplus Energy Revenue		-	-	-	-	-	-	-	-	-	-	-	-	**-**	**-**
WAX RCA	-	408.51	(369)	(409)	(409)	(423)	(375)	(423)	(423)	(409)	(423)	(409.16)	(423)	**(4,902)**	**(4,902)**
WAX CEPSA Sales		(236)	(530)	(386)	(314)	(240)	(193)	(509)	(778)	(347)	(244)	(262)	(275)	**(4,312)**	**(4,227)**
Market Savings		(167)	(167)	(167)	(167)	(167)	(167)	(167)	(167)	(167)	(167)	(167)	(167)	**(2,000)**	**(1,000)**
Special & Accounting Adjustments														**-**	**-**
Balancing Pool Adjustments		(376)	85	1,128	-	(827)	(486)	1,313	(584)	(584)	-	(574)	905	**-**	**-**
Total Other Expense ($000)		(1,187)	(981)	167	(890)	(1,656)	(1,220)	215	(1,951)	(1,506)	(833)	(1,411)	40	**(11,214)**	(10,129)
Total Power Purchase Expense		**15,674**	**14,008**	**13,407**	**7,327**	**6,386**	**7,044**	**9,999**	**11,579**	**10,662**	**9,773**	**13,876**	**16,479**	**136,216**	**138,674**
Average Power Purchase Cost	Av	66.08	70.49	78.11	58.60	47.09	52.69	78.09	76.56	89.82	70.65	70.63	71.26		
Cummulative Balancing Pool	Cu	(1,624)	(1,540)	(412)	(412)	(1,239)	(1,725)	(412)	(995)	(1,579)	(1,579)	(2,153)	(1,248)		
Balancing to General Ledger															
Original PP Estimate for G/L		15,674	14,008	13,407	7,327	6,386	7,044	9,999	11,579	10,662	9,773	13,876	16,479	**136,216**	
Actual Booked within Month														**-**	
Previous Month Adjustment														**-**	
Reconciling Items														**-**	
Balancing Adjustments														**-**	
Current Month Adjustment		-												**-**	
Total Power Purchase FBC Reg		**15,674**	**14,008**	**13,407**	**7,327**	**6,386**	**7,044**	**9,999**	**11,579**	**10,662**	**9,773**	**13,876**	**16,479**	**136,216**	

POWER SUPPLY CALCULATIONS IF PURCHASED AT BC HDYRO 3808 RATES
USED FOR CLASSIFICATION OF HYDRO PLANT
Schedule 5.3

Current Forecast - Updated with Actuals									-				
2015 RRA Evidentary Update													-
Actual Power Purchase Exp.													-
Variance from Forecast	-	-	-	-	-	-	-	-	-	-	-	-	-
Surplus Sales Estimate	(644.7)	(899.3)	(794.2)	(723.3)	(662.4)	(567.2)	(931.4)	(1,200.5)	(756.2)	(666.6)	(670.8)	(697.7)	(9,214.4)
Previous Month Adjustment	-	-	-	-	-	-							-
Current Month Adjustment				-	-	-							-
Monthly Surplus Sales Booked	(644.7)	(899.3)	(794.2)	(723.3)	(662.4)	(567.2)	(931.4)	(1,200.5)	(756.2)	(666.6)	(670.8)	(697.7)	(9,214.4)
Total Power Purchase FBC Cons	**16,319**	**14,908**	**14,201**	**8,051**	**7,048**	**7,611**	**10,930**	**12,780**	**11,419**	**10,440**	**14,547**	**17,177**	**145,430**

Analysis of Forecast Wheeling Expense for Year Ending December 31, 2017

#	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
Nomination (MW)														
	200	200	200	200	200	200	200	200	200	210	210	210	**2,430**	
	36	36	36	36	36	36	36	36	36	36	36	36	**432**	
Rate ($/kW/month)														
	1,790	1,790	1,790	1,790	1,790	1,790	1,790	1,790	1,790	1,829	1,829	1,829		
	1,166	1,166	1,166	1,166	1,166	1,166	1,166	1,166	1,166	1,192	1,192	1,192		
	-	-	-	-	-	-	-	-	-	-	-	-		
Cost ($000)														
	358	358	358	358	358	358	358	358	358	384	384	384	**4,374**	
	42	42	42	42	42	42	42	42	42	43	43	43	**507**	
	-	-	-	-	-	-	-	-	-	-	-	-		
Excess Wheeling Costs ($000)														
	3	3	3	3	3	3	3	3	3	3	3	3	**36**	
	1	1	1	1	1	1	1	1	1	1	1	1	**12**	48
Tc	**404**	**404**	**404**	**404**	**404**	**404**	**404**	**404**	**404**	**431**	**431**	**431**	**4,928**	

Wheeling Revenue Forecast - Booked in Other Income

#	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(807)
	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(26)	(317)
	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(55)
Tc	**(98)**	**(98)**	**(98)**	**(98)**	**(98)**	**(98)**	**(98)**	**(98)**	**(98)**	**(98)**	**(98)**	**(98)**	**(1,179)**

Forecast of Water Fee Expense for Year Ending December 31, 2017

2014 Rates

1.344	mills/kwh	NOTE: ONLY USED FOR THE REVENUE REQUIREMENT PROCESS AT THIS TIME. NOT UPDATED. SEE PAT SMITH FOR WATER FEE QUESTIONS.
6.268	mills/kwh	
4.478	$/kw/year	

FBC Inc.		**Brilliant**			
1615	GWH		Previous Year Generation	859.379	GWH

POWER SUPPLY CALCULATIONS IF PURCHASED AT BC HDYRO 3808 RATES
USED FOR CLASSIFICATION OF HYDRO PLANT
Schedule 5.3

Upgrade Outage	GWH	Upgrade Outage		GWH
Upgrade Output	GWH	Upgrade Output		GWH
1615	GWH	Total Generation	859.4	GWH
Tc 10313.721		Total Payments ($000)	5266.967	

#	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
FBC Payment Schedule			5,157						5,157				**10,314**
Brilliant Payment Schedule			2,633						2,633				**5,267**

CLASSIFICATION and ALLOCATION BY FUNCTION
Schedule 6.1

Classification Factors	Production			Transmission			Distribution				Total % Allocated
	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA	
CP1	100.00%			100.00%			100.00%				100%
CP2	100.00%			100.00%			100.00%				100%
CP4	100.00%			100.00%			100.00%				100%
CP12	100.00%			100.00%			100.00%				100%
TCP1				100.00%							100%
TCP2				100.00%							100%
TCP4				100.00%							100%
TCP12				100.00%							100%
NCP	100.00%			100.00%			100.00%				100%
NCPP	100.00%			100.00%			100.00%				100%
NCPS	100.00%			100.00%			100.00%				100%
kWh		100.00%			100.00%			100.00%			100%
CUST									100.00%		100%
CUSTW									100.00%		100%
CUSTM									100.00%		100%
CUSTR									100.00%		100%
MINSYSP							19.00%		81.00%		100%
MINSYSC							35.00%		65.00%		100%
MINSYST							31.00%		69.00%		100%
20D/80E	19.83%	80.17%									
DA1			100.00%			100.00%				100.00%	100%
REV	13.19%	37.50%		17.47%			14.16%		17.31%	0.37%	100%
RB	3.59%	14.42%		27.26%			27.30%		26.68%	0.74%	100%
RBG	19.83%	80.17%									100%
RBT				100.00%							100%
RBD							47.34%		51.47%	1.18%	100%
RBGP	5.23%	21.16%		20.61%			22.27%		30.17%	0.56%	100%
OM	22.81%	61.29%		10.13%			1.88%		3.84%	0.04%	100%
OMAG	5.51%	22.28%		37.58%			6.99%		27.50%	0.15%	100%
GPLT	2.79%	11.30%		26.17%			28.28%		30.75%	0.71%	100%
NETPLT	3.09%	12.49%		25.34%			27.76%		30.63%	0.69%	100%
LABOR	5.56%	22.50%		21.92%			23.68%		25.75%	0.59%	100%
PURCHkWh		100.00%									
PURCHkW	100.00%										
DSM	16.60%	71.60%		3.59%			3.93%		4.27%		100%
RBASE	3.59%	14.42%		27.26%			27.30%		26.68%	0.74%	100%
	P % of Total	50%		T % of Total	18%		D % of Total	32%			
	Total	100%									

CLASSIFICATION AND ALLOCATION BY CUSTOMER
Schedule 6.2

Classification Factors	Total Allocated	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering	
CP1	100%	52.271%	8.000%	13.014%	5.911%	1.995%	0.209%	0.074%	14.641%	3.885%	52.172%	0.099%	100%
CP2	100%	50.387%	8.121%	14.149%	6.836%	2.435%	0.118%	0.625%	14.761%	2.569%	50.266%	0.121%	100%
CP4	100%	51.629%	7.923%	14.079%	6.115%	2.284%	0.249%	0.080%	14.325%	3.317%	51.518%	0.111%	100%
CP12	100%	47.256%	8.523%	16.593%	8.132%	2.527%	0.179%	0.649%	13.953%	2.189%	47.169%	0.087%	100%
TCP1	100%	52.271%	8.000%	13.014%	5.911%	1.995%	0.209%	0.074%	14.641%	3.885%	52.172%	0.099%	100%
TCP2	100%	50.387%	8.121%	14.149%	6.836%	2.435%	0.118%	0.625%	14.761%	2.569%	50.266%	0.121%	100%
TCP4	100%	51.629%	7.923%	14.079%	6.115%	2.284%	0.249%	0.080%	14.325%	3.317%	51.518%	0.111%	100%
TCP12	100%	47.256%	8.523%	16.593%	8.132%	2.527%	0.179%	0.649%	13.953%	2.189%	47.169%	0.087%	100%
NCP	100%	47.689%	8.339%	15.485%	7.656%	2.184%	0.452%	1.112%	13.476%	3.607%	47.554%	0.136%	100%
NCPP	100%	50.621%	8.851%	16.437%	8.126%		0.480%	1.181%	14.304%		50.477%	0.144%	100%
NCPS	100%	65.259%	11.411%	21.190%			0.618%	1.522%			65.073%	0.186%	100%
kWh	100%	42.043%	9.451%	17.861%	9.081%	2.758%	0.449%	1.251%	14.766%	2.340%	41.96%	0.087%	100%
CUST	100%	86.354%	10.426%	1.166%	0.034%	0.003%	1.188%	0.818%	0.009%	0.002%	86.226%	0.128%	100%
CUSTW	100%	78.427%	9.469%	1.059%	6.320%	0.550%	1.510%	1.040%	1.300%	0.325%	78.31%	0.23%	100%
CUSTM	100%	61.093%	22.191%	3.873%	0.563%	4.460%		0.579%	5.792%	1.448%	61.00%	0.18%	100%
CUSTR	100%	86.354%	10.426%	1.166%	0.034%	0.003%	1.188%	0.818%	0.009%	0.002%	86.23%	0.13%	100%
MINSYSP	100%	80.121%	10.224%	4.248%	1.263%	0.002%	1.059%	0.900%	2.182%	0.002%	79.99%	0.13%	100%
MINSYSC	100%	74.872%	10.054%	6.844%	2.298%	0.002%	0.950%	0.969%	4.011%	0.001%	74.74%	0.14%	100%
MINSYST	100%	79.814%	10.731%	7.373%	0.024%	0.002%	1.011%	1.036%	0.006%	0.002%	79.67%	0.15%	100%
20D/80E	100%	43.698%	9.187%	17.125%	8.636%	2.694%	0.383%	1.127%	14.765%	2.385%	43.604%	0.093%	100%
DA1	100%						100.000%						100%
REV	100%	52.214%	9.304%	14.018%	6.870%	1.847%	0.846%	0.942%	12.242%	1.716%	52.10%	0.11%	100%
RB	100%	57.109%	9.404%	12.247%	5.738%	1.277%	1.245%	0.920%	10.889%	1.172%	56.99%	0.13%	100%
RBG	100%	43.698%	9.187%	17.125%	8.636%	2.694%	0.383%	1.127%	14.765%	2.385%	43.604%	0.093%	100%
RBT	100%	50.387%	8.121%	14.149%	6.836%	2.435%	0.118%	0.625%	14.761%	2.569%	50.27%	0.12%	100%
RBT-D	100%	50.387%	8.121%	14.149%	6.836%	2.435%	0.118%	0.625%	14.761%	2.569%	50.266%	0.121%	100%
RBT-E													
RBT-DA													
RBD	100%	65.012%	10.098%	9.667%	4.217%	0.225%	2.066%	1.000%	7.642%	0.073%	64.878%	0.139%	100%
RBGP	100%	57.812%	9.517%	12.004%	5.629%	1.330%	1.099%	0.944%	10.467%	1.197%	57.69%	0.123%	100%
OM	100%	46.017%	9.172%	16.341%	8.117%	2.490%	0.418%	0.960%	14.152%	2.333%	45.92%	0.095%	100%
OMAG	100%	56.805%	9.169%	11.795%	6.251%	1.789%	0.669%	0.881%	10.957%	1.684%	56.69%	0.129%	100%
GPLT	100%	58.794%	9.444%	11.702%	5.416%	1.136%	1.244%	0.917%	10.300%	1.047%	58.67%	0.127%	100%
NETPLT	100%	58.661%	9.453%	11.748%	5.446%	1.156%	1.232%	0.922%	10.323%	1.061%	58.54%	0.127%	100%
LABOR	100%	55.83%	9.41%	12.74%	6.03%	1.40%	1.17%	0.95%	11.20%	1.27%	55.71%	0.122%	100%
PURCHkWh	100%	42.22%	9.43%	17.75%	9.06%	2.74%	0.45%	1.19%	14.77%	2.39%	42.13%	0.087%	100%
PURCHkW	100%	47.78%	8.63%	15.98%	7.54%	2.37%	0.21%	0.45%	14.37%	2.67%	47.69%	0.091%	100%

Fortis BC 2017 COSA

COINCIDENT PEAK DEMAND ALLOCATION - PRODUCTION
Schedule 6.3

Calculation of 1 CP Allocation - Production

	Total Allocated	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-17												
Feb-17												
Mar-17												
Apr-17												
May-17												
Jun-17												
Jul-17												
Aug-17												
Sep-17												
Oct-17												
Nov-17												
Dec-17	761,499	398,046	60,922	99,104	45,014	15,189	1,588	563	111,489	29,584	397,291	755
Total Annual 1CP	761,499	398,046	60,922	99,104	45,014	15,189	1,588	563	111,489	29,584	397,291	755
% of Total	100%	52.27%	8.00%	13.01%	5.91%	1.99%	0.21%	0.07%	14.64%	3.88%	52.17%	0.10%

Calculation of 2 CP & 4 CP Allocation - Production

	Total Allocated	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
2 CP - Production												
Jan-17	671,526	366,578	49,664	73,418	36,288	16,374	1,555	548	100,598	26,502	365,916	662
Feb-17												
Mar-17												
Apr-17												
May-17												
Jun-17												
Jul-17	617,703	302,092	56,591	93,768	42,867	16,573		7,294	92,105	6,414	301,155	937
Aug-17	623,337	280,665	49,995	112,057	58,628	16,989		8,294	90,519	6,188	279,774	891
Sep-17												
Oct-17												
Nov-17												
Dec-17	761,499	398,046	60,922	99,104	45,014	15,189	1,588	563	111,489	29,584	397,291	755
2 Winter + 2 Summer	2,674,064	1,347,381	217,171	378,347	182,797	65,125	3,143	16,700	394,712	68,688	1,344,137	3,244
% of Total	100%	50.39%	8.12%	14.15%	6.84%	2.44%	0.12%	0.62%	14.76%	2.57%	50.27%	0.12%

4 CP - Production

Jan-17	671,526	366,578	49,664	73,418	36,288	16,374	1,555	548	100,598	26,502	365,916	662
Feb-17	636,036	308,802	51,445	101,304	45,298	14,500	1,923	686	90,539	21,538	308,204	598
Mar-17												
Apr-17												
May-17												
Jun-17												
Jul-17												
Aug-17												
Sep-17												
Oct-17												
Nov-17	571,018	289,621	47,140	97,864	34,836	14,233	1,510	308	75,559	9,946	288,705	917
Dec-17	761,499	398,046	60,922	99,104	45,014	15,189	1,588	563	111,489	29,584	397,291	755
4 Winter	2,640,078	1,363,048	209,171	371,690	161,436	60,297	6,577	2,106	378,185	87,571	1,360,116	2,932
% of Total	100%	51.63%	7.92%	14.08%	6.11%	2.28%	0.25%	0.08%	14.32%	3.32%	51.52%	0.11%

Calculation of 12 CP Allocation - Production

	Total Allocated	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Power Supply												
Winter	2,642,529	1,365,498	209,171	371,690	161,436	60,297	6,577	2,106	378,185	87,571	1,360,116	5,382
% of Total	100%	51.67%	7.92%	14.07%	6.11%	2.28%	0.25%	0.08%	14.31%	3.31%	51.47%	0.20%
Summer	4,241,258	1,887,490	377,503	770,555	398,340	113,678	5,745	42,538	582,328	63,081	1,886,881	609
% of Total	100%	44.50%	8.90%	18.17%	9.39%	2.68%	0.14%	1.00%	13.73%	1.49%	44.49%	0.01%
Annual	6,883,787	3,252,988	586,673	1,142,244	559,776	173,975	12,322	44,644	960,513	150,652	3,246,997	5,991
% of Total	100%	47.26%	8.52%	16.59%	8.13%	2.53%	0.18%	0.65%	13.95%	2.19%	47.17%	0.09%
Utility Owned Transmission												
Annual	6,883,787	3,252,988	586,673	1,142,244	559,776	173,975	12,322	44,644	960,513	150,652	3,246,997	5,991
% of Total	100%	47.26%	8.52%	16.59%	8.13%	2.53%	0.18%	0.65%	13.95%	2.19%	47.17%	0.09%

Fortis BC 2017 COSA

COINCIDENT PEAK DEMAND ALLOCATION - TRANSMISSION
Schedule 6.4

Calculation of 1 CP Allocation - Transmission

	Total Allocated	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-17												
Feb-17												
Mar-17												
Apr-17												
May-17												
Jun-17												
Jul-17												
Aug-17												
Sep-17												
Oct-17												
Nov-17												
Dec-17	761,499	398,046	60,922	99,104	45,014	15,189	1,588	563	111,489	29,584	397,291	755
Total Annual 1CP	761,499	398,046	60,922	99,104	45,014	15,189	1,588	563	111,489	29,584	397,291	755
% of Total	100%	52.27%	8.00%	13.01%	5.91%	1.99%	0.21%	0.07%	14.64%	3.88%	52.17%	0.10%

Calculation of 2 CP & 4 CP Allocation - Transmission

	Total Allocated	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
2 CP - Transmission												
Jan-17	671,526	366,578	49,664	73,418	36,288	16,374	1,555	548	100,598	26,502	365,916	662
Feb-17												
Mar-17												
Apr-17												
May-17												
Jun-17												
Jul-17	617,703	302,092	56,591	93,768	42,867	16,573		7,294	92,105	6,414	301,155	937
Aug-17	623,337	280,665	49,995	112,057	58,628	16,989		8,294	90,519	6,188	279,774	891
Sep-17												
Oct-17												
Nov-17												
Dec-17	761,499	398,046	60,922	99,104	45,014	15,189	1,588	563	111,489	29,584	397,291	755
2 Winter + 2 Summer	2,674,064	1,347,381	217,171	378,347	182,797	65,125	3,143	16,700	394,712	68,688	1,344,137	3,244
% of Total	100%	50.39%	8.12%	14.15%	6.84%	2.44%	0.12%	0.62%	14.76%	2.57%	50.27%	0.12%

4 CP - Transmission

Jan-17	671,526	366,578	49,664	73,418	36,288	16,374	1,555	548	100,598	26,502	365,916	662
Feb-17	636,036	308,802	51,445	101,304	45,298	14,500	1,923	686	90,539	21,538	308,204	598
Mar-17												
Apr-17												
May-17												
Jun-17												
Jul-17												
Aug-17												
Sep-17												
Oct-17												
Nov-17	571,018	289,621	47,140	97,864	34,836	14,233	1,510	308	75,559	9,946	288,705	917
Dec-17	761,499	398,046	60,922	99,104	45,014	15,189	1,588	563	111,489	29,584	397,291	755
4 Winter	2,640,078	1,363,048	209,171	371,690	161,436	60,297	6,577	2,106	378,185	87,571	1,360,116	2,932
% of Total	100%	51.63%	7.92%	14.08%	6.11%	2.28%	0.25%	0.08%	14.32%	3.32%	51.52%	0.11%

Calculation of 12 CP Allocation - Transmission
Utility Owned Transmission

Annual	6,883,787	3,252,988	586,673	1,142,244	559,776	173,975	12,322	44,644	960,513	150,652	3,246,997	5,991
% of Total	100%	47.26%	8.52%	16.59%	8.13%	2.53%	0.18%	0.65%	13.95%	2.19%	47.17%	0.09%

Fortis BC 2017 COSA

NON-COINCIDENT PEAK DEMAND ALLOCATION
Schedule 6.5

NCP Distribution Allocation

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Winter												
NCP at Input (NCP)	843,852	407,445	71,243	132,301	65,409	18,660	1,923	918	115,136	30,817	406,286	1,159
% of Total	100%	48.28%	8.44%	15.68%	7.75%	2.21%	0.23%	0.11%	13.64%	3.65%	48.15%	0.14%
NCP Primary (NCPP)	761,224	390,441	68,270	126,779	62,680		1,843	880	110,331		389,331	1,110
% of Total	100%	51.29%	8.97%	16.65%	8.23%		0.24%	0.12%	14.49%		51.15%	0.15%
NCP Secondary (NCPS)	556,000	368,982	64,558	119,886			1,743	832			368,162	1,050
% of Total	100%	66.36%	11.61%	21.56%			0.31%	0.15%			66.22%	0.19%
Summer												
NCP at Input (NCP)	720,194	300,505	71,176	130,956	64,428	17,824	3,860	9,504	101,127	20,813	299,450	1,055
% of Total	100%	41.73%	9.88%	18.18%	8.95%	2.47%	0.54%	1.32%	14.04%	2.89%	41.58%	0.15%
NCP Primary (NCPP)	653,113	287,964	68,205	125,491	61,739		3,699	9,107	96,907		286,953	1,011
% of Total	100%	44.09%	10.44%	19.21%	9.45%		0.57%	1.39%	14.84%		43.94%	0.15%
NCP Secondary (NCPS)	467,581	272,306	64,497	118,668			3,498	8,612			271,350	956
% of Total	100%	58.24%	13.79%	25.38%			0.75%	1.84%			58.03%	0.20%
Annual												
NCP at Input (NCP)	854,376	407,445	71,243	132,301	65,409	18,660	3,860	9,504	115,136	30,817	406,286	1,159
% of Total	100%	47.69%	8.34%	15.49%	7.66%	2.18%	0.45%	1.11%	13.48%	3.61%	47.55%	0.14%
NCP Primary (NCPP)	771,308	390,441	68,270	126,779	62,680		3,699	9,107	110,331		389,331	1,110
% of Total	100%	50.62%	8.85%	16.44%	8.13%		0.48%	1.18%	14.30%		50.48%	0.14%
NCP Secondary (NCPS)	565,766	369,212	64,558	119,886			3,498	8,612			368,162	1,050
% of Total	100%	65.26%	11.41%	21.19%			0.62%	1.52%			65.07%	0.19%

NCP Distribution Allocation for Minimum System (including PLCC adjustment)

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Max NCP	854,376	407,445	71,243	132,301	65,409	18,660	3,860	9,504	115,136	30,817	406,286	1,159
NCP Weighting	-	-	-	-	-	-	-	-	-	-	-	-
Max NCPP	771,308	390,441	68,270	126,779	62,680	-	3,699	9,107	110,331	-	389,331	1,110
NCPP Weighting	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%

Max NCPS	565,766	369,212	64,558	119,886	-	-	3,498	8,612	-	-	368,162	1,050
NCPS Weighting	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Weighted NCP (P+ S)	730,200	386,195	67,528	125,401	50,144	-	3,659	9,008	88,265	-	385,097	1,098
		52.9%	9.2%	17.2%	6.9%		0.5%	1.2%	12.1%		52.7%	0.2%
Transformers	771,308	51%	9%	16%	8%		0%	1%	14%		50%	0%
Distribution Customers (Primary + Secondary)	133,848	115,595	13,956	1,561	46		1,590	1,095	5		115,424	171
	100%	86.4%	10.4%	1.2%	0.0%		1.2%	0.8%	0.0%		86.2%	0.1%
Distribution Customers (Secondary)	133,797	115,595	13,956	1,561			1,590	1,095			115,424	171
	100%	86.4%	10.4%	1.2%			1.2%	0.8%			86.3%	0.1%
Distribution Customers (Transformers)	133,848	115,595	13,956	1,561	46	-	1,590	1,095	5	-	115,424	171
	100%	86.4%	10.4%	1.2%	0.0%		1.2%	0.8%	0.0%		86.2%	0.1%
PLCC Amount		1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
NCP After PLCC (P+S)	584,306	260,197	52,316	123,699	50,094		1,926	7,815	88,260		259,285	912
	100%	44.5%	9.0%	21.2%	8.6%		0.3%	1.3%	15.1%		44.4%	0.2%
NCP After PLCC (S)	419,927	243,213	49,346	118,184			1,765	7,419			242,349	864
	100%	57.9%	11.8%	28.1%			0.4%	1.8%			57.7%	0.2%
NCP After PLCC (Transformers)	625,414	264,443	53,058	125,078	62,630		1,966	7,914	110,326		263,519	924
	100%	42.3%	8.5%	20.0%	10.0%		0.3%	1.3%	17.6%		42.1%	0.1%
Rate Base Items												
Poles, Towers, & Fixtures	227,312,500											
Customer	184,123,125	$159,014,051	$19,198,176	$2,147,220	$63,278		$2,187,226	$1,506,297	$6,878		$158,778,993	$235,058
Demand (before PLCC)	43,189,375	$22,842,422	$3,994,088	$7,417,112	$2,965,868		$216,426	$532,819	$5,220,641		$22,777,467	$64,955
Demand (after PLCC)	43,189,375	$19,232,635	$3,866,950	$9,143,318	$3,702,705		$142,361	$577,635	$6,523,771		$19,165,228	$67,407
Adjusted Customer	184,123,125	$155,404,263	$19,071,038	$3,873,426	$800,115		$2,113,161	$1,551,113	$1,310,008		$155,166,754	$237,509
Adjusted Demand	43,189,375	$22,842,422	$3,994,088	$7,417,112	$2,965,868		$216,426	$532,819	$5,220,641		$22,777,467	$64,955
Conductors & Devices	302,094,500											
Customer	196,361,425	$169,583,400	$20,474,241	$2,289,941	$67,484		$2,332,606	$1,606,417	$7,335		$169,332,718	$250,682
Demand (before PLCC)	105,733,075	$55,921,150	$9,778,036	$18,158,031	$7,260,822		$529,837	$1,304,408	$12,780,791		$55,762,131	$159,019
Demand (after PLCC)	105,733,075	$47,083,932	$9,466,785	$22,384,003	$9,064,692		$348,518	$1,414,124	$15,971,020		$46,918,912	$165,020
Adjusted Customer	196,361,425	$160,746,183	$20,162,990	$6,515,913	$1,871,354		$2,151,287	$1,716,134	$3,197,564		$160,489,499	$256,683
Adjusted Demand	105,733,075	$55,921,150	$9,778,036	$18,158,031	$7,260,822		$529,837	$1,304,408	$12,780,791		$55,762,131	$159,019
Line Transformers	136,913,500											
Customer	94,470,315	$81,587,294	$9,850,244	$1,101,700	$32,467		$1,122,227	$772,854	$3,529		$81,466,689	$120,604
Demand (before PLCC)	42,443,185	$21,485,012	$3,756,740	$6,976,350	$3,449,107		$203,564	$501,156	$6,071,256		$21,423,916	$61,095
Demand (after PLCC)	42,443,185	$17,946,175	$3,600,740	$8,488,303	$4,250,299		$133,436	$537,064	$7,487,167		$17,883,468	$62,707
Adjusted Customer	94,470,315	$78,048,457	$9,694,245	$2,613,654	$833,659		$1,052,098	$808,763	$1,419,440		$77,926,241	$122,216
Adjusted Demand	42,443,185	$21,485,012	$3,756,740	$6,976,350	$3,449,107		$203,564	$501,156	$6,071,256		$21,423,916	$61,095

Fortis BC 2017 COSA

FORECAST OF REVENUES FROM CURRENT RATES

Schedule 7.1

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Number of Customers												
Jan-17	124,886	107,679	12,952	1,513	46	4	1,590	1,095	5	1	107,525	155
Feb-17	136,023	117,632	13,792	1,858	46	4	1,590	1,095	5	1	117,494	138
Mar-17	136,255	117,685	13,974	1,856	46	4	1,590	1,095	5	1	117,530	155
Apr-17	133,617	115,231	14,202	1,443	46	4	1,590	1,095	5	1	115,107	125
May-17	136,780	117,922	14,378	1,740	46	4	1,590	1,095	5	1	117,781	141
Jun-17	129,233	111,172	13,851	1,470	46	4	1,590	1,095	5	1	111,020	152
Jul-17	133,657	115,747	13,934	1,234	46	4	1,590	1,095	5	1	115,566	182
Aug-17	138,258	119,456	14,325	1,736	46	4	1,590	1,095	5	1	119,270	186
Sep-17	132,809	114,658	13,953	1,458	46	4	1,590	1,095	5	1	114,481	177
Oct-17	133,277	115,503	13,796	1,237	46	4	1,590	1,095	5	1	115,330	173
Nov-17	136,260	117,541	14,254	1,724	46	4	1,590	1,095	5	1	117,309	233
Dec-17	135,180	116,914	14,064	1,462	46	4	1,590	1,095	5	1	116,677	237
Total / Average	133,853	115,595	13,956	1,561	46	4	1,590	1,095	5	1	115,424	171
									Per POD	Per Cust		
Customer Charge Revenues	**Rate: $/Month**	$16.05	$19.40	$16.48	$945.04	$3,116.03	$150.60	$20.96	$2,645.03	$5,974.48	$16.05	$16.05
	Rate 37 Misc $											
Jan-17	$2,358,280	$1,727,712	$251,273	$24,942	$43,472	$12,464	$239,460	$21,243	$31,740	$5,974	$1,725,233	$2,479
Feb-17	$2,539,939	$1,887,413	$267,558	$30,615	$43,472	$12,464	$239,460	$21,243	$31,740	$5,974	$1,885,199	$2,214
Mar-17	$2,544,277	$1,888,255	$271,087	$30,581	$43,472	$12,464	$239,460	$21,243	$31,740	$5,974	$1,885,776	$2,479
Apr-17	$2,504,250	$1,848,886	$275,519	$23,783	$43,472	$12,464	$239,460	$22,951	$31,740	$5,974	$1,846,888	$1,998
May-17	$2,555,715	$1,892,052	$278,929	$28,673	$43,472	$12,464	$239,460	$22,951	$31,740	$5,974	$1,889,790	$2,262
Jun-17	$2,432,736	$1,783,747	$268,701	$24,226	$43,472	$12,464	$239,460	$22,951	$31,740	$5,974	$1,781,316	$2,431
Jul-17	$2,503,892	$1,857,163	$270,325	$20,342	$43,472	$12,464	$239,460	$22,951	$31,740	$5,974	$1,854,251	$2,912
Aug-17	$2,579,250	$1,916,678	$277,906	$28,605	$43,472	$12,464	$239,460	$22,951	$31,740	$5,974	$1,913,693	$2,984
Sep-17	$2,490,457	$1,839,687	$270,686	$24,022	$43,472	$12,464	$239,460	$22,951	$31,740	$5,974	$1,836,847	$2,840
Oct-17	$2,497,331	$1,853,239	$267,638	$20,393	$43,472	$12,464	$239,460	$22,951	$31,740	$5,974	$1,850,471	$2,768
Nov-17	$2,545,244	$1,885,951	$276,522	$28,417	$43,472	$12,464	$239,460	$21,243	$31,740	$5,974	$1,882,221	$3,730
Dec-17	$2,527,154	$1,875,879	$272,832	$24,090	$43,472	$12,464	$239,460	$21,243	$31,740	$5,974	$1,872,076	$3,803
Total	$30,078,526	$22,256,661	$3,248,976	$308,687	$521,662	$149,569	$2,873,518	$266,873	$380,884	$71,694	$22,223,761	$32,900
Forecast kWh												
Jan-17	334,532,193	154,371,972	29,516,000	50,133,121	25,343,646	8,203,646	1,203,487	732,926	52,750,835	12,276,559	154,121,493	341,985
Feb-17	288,402,541	129,110,557	26,223,172	45,515,846	21,502,516	8,387,132	1,203,487	804,317	45,601,441	10,054,074	128,942,871	228,947
Mar-17	272,510,237	118,357,419	25,413,328	46,193,262	24,991,816	5,497,532	1,203,487	726,372	41,375,283	8,751,737	118,150,685	282,260
Apr-17	234,375,781	87,796,113	21,925,230	43,231,138	26,003,234	11,937,039	1,203,487	2,707,550	34,650,929	4,921,061	87,675,178	165,116
May-17	234,155,473	86,944,285	22,600,321	45,702,648	28,018,850	7,769,132	1,203,487	5,592,467	35,373,329	950,953	86,810,547	182,597
Jun-17	242,877,732	92,136,016	23,781,193	47,591,016	24,403,921	8,269,660	1,203,487	5,669,013	37,355,103	2,468,322	92,012,127	169,149
Jul-17	259,685,505	99,976,079	25,852,493	51,240,438	22,308,651	7,039,341	1,203,487	7,054,952	41,075,563	3,934,501	99,842,341	182,597
Aug-17	281,553,105	106,215,184	27,273,526	53,594,838	28,957,733	7,903,158	1,203,487	8,862,610	43,629,749	3,912,820	106,091,090	169,428
Sep-17	230,199,202	82,311,173	21,646,041	44,898,377	28,029,216	8,140,435	1,203,487	4,609,549	35,170,055	4,190,867	82,130,032	247,317
Oct-17	248,730,284	101,707,177	23,009,948	45,528,774	21,797,607	7,481,726	1,203,487	2,134,780	38,930,329	6,936,455	101,568,183	189,773

Nov-17	274,082,305	112,104,205	24,345,136	46,059,544	32,073,599	7,767,778	1,203,487	630,238	41,258,244	8,640,074	111,875,539	312,203
Dec-17	380,466,953	182,002,194	32,737,110	55,420,405	27,667,898	7,579,589	1,203,487	763,623	58,709,715	14,382,932	181,770,914	315,773
Total / Average	3,281,571,311	1,353,032,375	304,323,499	575,109,408	311,098,688	95,976,168	14,441,848	40,288,397	505,880,576	81,420,354	1,350,990,999	2,787,141

Forecast kWh for Rate 37

Jan-17	-											
Feb-17	-											
Mar-17	-											
Apr-17	-											
May-17	-											
Jun-17	-											
Jul-17	-											
Aug-17	-											
Sep-17	-											
Oct-17	-											
Nov-17	-											
Dec-17	-											
Total / Average	-	-	-	-	-	-	-	-	-	-	-	-

Energy Rates

Flat Rate:	Flat Rate $/kWh		$0.10195		$0.05571	$0.05516			$0.05441	$0.04501		
Seasonal Rate:	Jan $/kWh							$0.10195				
	Feb $/kWh							$0.10195				
	Mar $/kWh							$0.10195				
	Ap $/kWh							$0.07259				
	May $/kWh							$0.07259				
	Jun $/kWh							$0.07259				
	Jul $/kWh							$0.07259				
	Aug $/kWh							$0.07259				
	Sep $/kWh							$0.07259				
	Oct $/kWh							$0.07259				
	Nov $/kWh							$0.10195				
	Dec $/kWh							$0.10195				
	Rate 37 $/kWh											
Block Rate:	1st Block kWh	800 KWh		8,000 KWh							800 KWh	800 KWh
	2nd Block kWh											
	3rd Block kWh											
	4th Block kWh											
	1st Block $/kWh	$0.1012		$0.0866							$0.1012	$0.1012
	2nd Block $/kWh	$0.1562		$0.0719							$0.1562	$0.1562
	3rd Block $/kWh											
	4th Block $/kWh											

Energy Revenues												
Jan-17	$31,838,748	$19,684,777	$3,009,156	$3,782,944	$1,411,895	$452,513		$74,722	$2,870,173	$552,568	$19,637,624	$47,154
Feb-17	$27,197,357	$16,411,922	$2,673,452	$3,435,735	$1,197,905	$462,634		$82,000	$2,481,174	$452,534	$16,381,212	$30,710
Mar-17	$25,193,597	$14,686,442	$2,590,889	$3,501,530	$1,392,294	$303,244		$74,054	$2,251,229	$393,916	$14,647,893	$38,549
Apr-17	$20,447,184	$10,542,719	$2,235,277	$3,258,706	$1,448,640	$658,447		$196,541	$1,885,357	$221,497	$10,522,672	$20,047
May-17	$20,158,778	$10,043,319	$2,304,103	$3,448,459	$1,560,930	$428,545		$405,957	$1,924,663	$42,802	$10,021,184	$22,135
Jun-17	$21,038,072	$10,661,030	$2,424,493	$3,581,748	$1,359,542	$456,154		$411,514	$2,032,491	$111,099	$10,640,975	$20,054
Jul-17	$22,457,129	$11,419,683	$2,635,662	$3,846,547	$1,242,815	$388,290		$512,119	$2,234,921	$177,092	$11,398,672	$21,011
Aug-17	$24,606,002	$12,561,965	$2,780,536	$4,020,979	$1,613,235	$435,938		$643,337	$2,373,895	$176,116	$12,542,932	$19,033
Sep-17	$19,560,063	$9,542,949	$2,206,814	$3,362,925	$1,561,508	$449,026		$334,607	$1,913,603	$188,631	$9,512,933	$30,016
Oct-17	$21,748,222	$11,760,517	$2,345,864	$3,429,432	$1,214,345	$412,692		$154,964	$2,118,199	$312,210	$11,739,583	$20,934
Nov-17	$24,021,254	$13,157,737	$2,481,987	$3,468,236	$1,786,820	$428,471		$64,253	$2,244,861	$388,890	$13,120,300	$37,437
Dec-17	$35,773,498	$22,398,696	$3,337,548	$4,158,163	$1,541,379	$418,090		$77,851	$3,194,396	$647,376	$22,358,643	$40,052
Subtotal	$294,039,904	$162,871,755	$31,025,781	$43,295,404	$17,331,308	$5,294,045		$3,031,918	$27,524,962	$3,664,730	$162,524,623	$347,132
Surcharge												
Total	$294,039,904	$162,871,755	$31,025,781	$43,295,404	$17,331,308	$5,294,045		$3,031,918	$27,524,962	$3,664,730	$162,524,623	$347,132
Metered Demand kVa or kW				All kVA	All kVA	All kVA						
Jan-17	431,139		101,039	122,787	62,817	19,097	-	-	99,372	26,027	-	-
Feb-17	432,800		96,932	140,394	61,865	16,852	-	-	93,783	22,975	-	-
Mar-17	417,985		94,605	141,241	64,300	18,241	-	-	79,159	20,440	-	-
Apr-17	408,722		98,258	134,339	73,340	17,729	-	-	66,041	19,016	-	-
May-17	426,736		93,318	163,461	78,870	17,564	-	-	66,807	6,715	-	-
Jun-17	444,004		106,567	147,147	67,712	17,483	-	-	94,942	10,152	-	-
Jul-17	421,926		106,350	128,469	62,745	17,819	-	-	95,952	10,590	-	-
Aug-17	485,305		103,255	178,846	77,735	17,854	-	-	96,784	10,832	-	-
Sep-17	415,092		94,229	148,362	76,398	17,497	-	-	67,091	11,514	-	-
Oct-17	381,898		96,237	119,369	59,177	17,882	-	-	71,678	17,555	-	-
Nov-17	467,289		106,990	158,014	80,804	18,057	-	-	82,695	20,729	-	-
Dec-17	485,742		111,027	145,116	70,785	17,678	-	-	110,873	30,264	-	-
Total / Average												
Total	5,218,638	-	1,208,807	1,727,546	836,548	213,753	-	-	1,025,177	206,807	-	-
Billed Demand kVa or kW				Over 45 kVA								
Jan-17	297,058			86,172	66,255	19,097			99,508	26,027	0	0
Feb-17	295,205			98,529	62,683	16,852			94,167	22,975	0	0
Mar-17	290,087			99,123	65,525	18,241			86,377	20,822	0	0
Apr-17	294,319			94,279	75,124	17,729			86,365	20,822	0	0
May-17	317,158			114,717	81,167	17,586			86,346	17,342	0	0
Jun-17	309,254			103,268	71,666	17,533			95,965	20,822	0	0
Jul-17	290,971			90,160	65,250	17,869			96,870	20,822	0	0
Aug-17	340,658			125,514	78,968	17,932			97,423	20,822	0	0
Sep-17	304,404			104,121	78,337	17,575			83,550	20,822	0	0
Oct-17	265,642			83,773	59,445	17,890			83,712	20,822	0	0
Nov-17	314,968			110,895	81,912	18,121			83,218	20,822	0	0
Dec-17	334,313			101,842	73,578	17,756			110,873	30,264	0	0
Total / Average				101,033								
Total	3,654,037	-	-	1,212,392	859,910	214,181	-	-	1,104,374	263,181	3	3

Billed Demand kVa for Rate 37												
Jan-17	-											
Feb-17	-											
Mar-17	-											
Apr-17	-											
May-17	-											
Jun-17	-											
Jul-17	-											
Aug-17	-											
Sep-17	-											
Oct-17	-											
Nov-17	-											
Dec-17	-											
Total / Average												
Total	-	-	-	-	-	-	-	-	-	-	-	-
	Power Rate: $/kVa					$2.77			$4.82	$4.77		
Demand Revenues	**Wires Rate: $/kVa**				$9.19	$4.93			$8.98	$6.34		
	Rate: $/kW			$7.72								
Jan-17				(Over 45 kVA)								
Feb-17												
Mar-17												
Apr-17												
May-17												
Jun-17												
Jul-17												
Aug-17												
Sep-17												
Oct-17												
Nov-17												
Dec-17												
Jan-17	$3,082,883			$665,246	$608,880	$147,047			$1,372,550	$289,161		
Feb-17	$3,019,355			$760,641	$576,058	$129,760			$1,297,648	$255,247		
Mar-17	$2,894,574			$765,226	$602,173	$140,456			$1,157,211	$229,508		
Apr-17	$2,871,330			$727,834	$690,391	$136,513			$1,093,878	$222,714		
May-17	$3,006,271			$885,617	$745,922	$135,351			$1,097,401	$141,980		
Jun-17	$3,090,533			$797,229	$658,615	$134,866			$1,319,390	$180,434		
Jul-17	$2,948,040			$696,032	$599,646	$137,453			$1,332,387	$182,521		
Aug-17	$3,357,573			$968,970	$725,713	$137,860			$1,341,352	$183,678		
Sep-17	$2,919,426			$803,812	$719,916	$135,111			$1,073,655	$186,932		
Oct-17	$2,643,725			$646,730	$546,296	$137,731			$1,097,222	$215,746		
Nov-17	$3,125,012			$856,106	$752,775	$139,354			$1,145,893	$230,885		
Dec-17	$3,465,189			$786,223	$676,186	$136,505			$1,530,045	$336,230		
Total	$36,423,911			$9,359,664	$7,902,570	$1,648,008			$14,858,633	$2,655,036		

Total Revenues		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-17	$37,279,912	$21,412,490	$3,260,429	$4,473,132	$2,064,246	$612,024	$239,460	$95,965	$4,274,463	$847,703	$21,362,857	$49,633
Feb-17	$32,756,651	$18,299,335	$2,941,010	$4,226,991	$1,817,435	$604,859	$239,460	$103,243	$3,810,563	$713,755	$18,266,411	$32,924
Mar-17	$30,632,448	$16,574,697	$2,861,976	$4,297,337	$2,037,939	$456,164	$239,460	$95,297	$3,440,180	$629,399	$16,533,668	$41,028
Apr-17	$25,822,765	$12,391,605	$2,510,797	$4,010,322	$2,182,503	$807,425	$239,460	$219,492	$3,010,976	$450,186	$12,369,560	$22,044
May-17	$25,720,764	$11,935,371	$2,583,032	$4,362,748	$2,350,324	$576,361	$239,460	$428,908	$3,053,804	$190,757	$11,910,974	$24,397
Jun-17	$26,561,341	$12,444,777	$2,693,193	$4,403,203	$2,061,629	$603,484	$239,460	$434,465	$3,383,622	$297,508	$12,422,292	$22,485
Jul-17	$27,909,061	$13,276,846	$2,905,987	$4,562,921	$1,885,933	$538,207	$239,460	$535,070	$3,599,049	$365,588	$13,252,923	$23,923
Aug-17	$30,542,824	$14,478,643	$3,058,442	$5,018,554	$2,382,420	$586,263	$239,460	$666,288	$3,746,987	$365,768	$14,456,626	$22,017
Sep-17	$24,969,945	$11,382,636	$2,477,500	$4,190,759	$2,324,895	$596,602	$239,460	$357,558	$3,018,998	$381,537	$11,349,780	$32,856
Oct-17	$26,889,279	$13,613,756	$2,613,502	$4,096,554	$1,804,113	$562,887	$239,460	$177,915	$3,247,161	$533,930	$13,590,054	$23,702
Nov-17	$29,691,511	$15,043,688	$2,758,509	$4,352,759	$2,583,067	$580,289	$239,460	$85,496	$3,422,494	$625,749	$15,002,521	$41,168
Dec-17	$41,765,841	$24,274,574	$3,610,380	$4,968,475	$2,261,036	$567,059	$239,460	$99,094	$4,756,181	$989,581	$24,230,719	$43,855
Subtotal	$360,542,341	$185,128,417	$34,274,757	$52,963,756	$25,755,540	$7,091,623	$2,873,518	$3,298,792	$42,764,479	$6,391,460	$184,748,384	$380,033
Surcharge												
Total	**$360,542,341**	$185,128,417	$34,274,757	$52,963,756	$25,755,540	$7,091,623	$2,873,518	$3,298,792	$42,764,479	$6,391,460	$184,748,384	$380,033

Fortis BC 2017 COSA

HISTORIC CUSTOMERS AND ENERGY SALES
Schedule 8.1

Number of Customers / Services	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-16	125,481	108,747	12,529	1,464	46	4	1,590	1,095	5	1	108,644	103
Feb-16	136,678	118,799	13,341	1,797	46	4	1,590	1,095	5	1	118,707	92
Mar-16	136,905	118,852	13,517	1,795	46	4	1,590	1,095	5	1	118,749	103
Apr-16	134,249	116,374	13,738	1,396	46	4	1,590	1,095	5	1	116,291	83
May-16	137,423	119,091	13,908	1,683	46	4	1,590	1,095	5	1	118,997	94
Jun-16	129,835	112,274	13,398	1,422	46	4	1,590	1,095	5	1	112,173	101
Jul-16	134,309	116,895	13,479	1,194	46	4	1,590	1,095	5	1	116,774	121
Aug-16	138,918	120,641	13,857	1,679	46	4	1,590	1,095	5	1	120,517	124
Sep-16	133,443	115,795	13,497	1,410	46	4	1,590	1,095	5	1	115,677	118
Oct-16	133,931	116,648	13,345	1,197	46	4	1,590	1,095	5	1	116,533	115
Nov-16	136,904	118,707	13,788	1,668	46	4	1,590	1,095	5	1	118,552	155
Dec-16	135,832	118,073	13,604	1,414	46	4	1,590	1,095	5	1	117,915	158
Total Average	134,492	116,741	13,500	1,510	46	4	1,590	1,095	5	1	116,627	114

Historic Energy, Demand And Customer Count
Historic Year

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Input Recorded Data												
Energy Sales (kWh)	3,105,059,354	1,231,552,608	297,122,438	561,500,870	314,622,434	95,976,168	14,441,848	42,280,995	471,650,840	75,911,154	1,229,694,514	1,858,094
Total Billing Capacity (kVa)	3,892,917			1,686,668	843,872	213,753			955,810	192,814		
Avg. Monthly Billing Capacity (kVa)	324,410			140,556	70,323	17,813			79,651	16,068		
Number of Customers	134,492	116,741	13,500	1,510	46	4	1,590	1,095	5	1	116,627	114
Ratio of NCP to Avg. Billing Capacity				83%	90%	102%			128%	174%		
Rate Classes NCP Demand at Meter	739,935	335,654	63,031	116,912	63,390	18,142	3,498	9,038	102,337	27,934	335,107	700
Estimated Based on Recorded Data												
Annual NCP Load Factor	48%	42%	54%	55%	57%	60%	47%	53%	52%	31%	42%	30%
Rate Classes CP Demand at Input Voltage	711,447	362,124	59,480	95,423	45,524	15,189	1,588	591	103,945	27,582	361,621	503
Annual CP Load Factor	50%	39%	57%	67%	79%	72%	104%	814%	52%	31%	39%	42%

Customer Information	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Weighting Factors for:												
Points of Delivery per Customer		1.0	1.0	1.0	1.0	1.0	1.0	1.0	2.4	3.0	1	1
Customers Meters & Services		$ 115.00	$ 202.00	$ 318.00	$ 318.00	$ 318.00	$ -	$ 239.00	$ 318.00	$ 318.00	115.0	125.0
Customer Retail		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Customer Accounting/Metering		1.000	1.000	1.000	202.500	202.500	1.400	1.400	159.700	159.700	1.00	2.00
Weighted Number of Customers												
Customers (PODs)	251,243	116,741	13,500	1,510	46	4	1,590	1,095	12.0	3	116,627	114
Customers Meters & Services	30,341,191	13,425,253	2,727,017	480,154	14,628	1,272	-	261,705	3,816	954	13,412,153	14,240
Customer Retail	251,243	116,741	13,500	1,510	46	4	1,590	1,095	12	3	116,627	114
Customer Accounting/Metering	264,886	116,741	13,500	1,510	9,315	810	2,226	1,533	1,916	479	116,627	228
Provided Services												
Power Purchased from Utility*		1	1	1	1	1	1	1	1	1	1	1
Reg & Shaping from Utility*		1	1	1	1	1	1	1	1	1	1	1
Uses Utility Transmission*		1	1	1	1	1	1	1	1	1	1	1
Uses Primary Distribution*		1	1	1	1		1	1	1		1	1
Uses Secondary Distribution*		1	1	1			1	1			1	1

* (yes=1,no=0)

Load Data And Customer Sales by Rate Class

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HISTORIC CUSTOMERS AND ENERGY SALES
Schedule 8.1

kWh Sales at the Meter		Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
	Jan-16	314,710,782	140,511,941	28,817,577	48,946,845	25,630,708	8,203,646	1,203,487	769,176	49,181,520	11,445,882	140,283,951	227,990
	Feb-16	271,630,516	117,518,580	25,602,666	44,438,826	21,746,070	8,387,132	1,203,487	844,097	42,515,880	9,373,778	117,365,949	152,631
	Mar-16	257,116,544	107,730,895	24,811,984	45,100,213	25,274,893	5,497,532	1,203,487	762,298	38,575,680	8,159,562	107,542,722	188,173
	Apr-16	222,702,247	79,913,485	21,406,423	42,208,180	26,297,767	11,937,039	1,203,487	2,841,461	32,306,320	4,588,084	79,803,408	110,077
	May-16	222,869,227	79,138,137	22,065,541	44,621,208	28,336,213	7,769,132	1,203,487	5,869,061	32,979,840	886,608	79,016,406	121,731
	Jun-16	230,778,806	83,863,737	23,218,470	46,464,893	24,680,339	8,269,660	1,203,487	5,949,393	34,827,520	2,301,306	83,750,971	112,766
	Jul-16	246,441,171	90,999,893	25,240,758	50,027,960	22,561,336	7,039,341	1,203,487	7,403,879	38,296,240	3,668,278	90,878,162	121,731
	Aug-16	267,652,625	96,678,830	26,628,166	52,326,649	29,285,731	7,903,158	1,203,487	9,300,940	40,677,600	3,648,064	96,565,878	112,952
	Sep-16	219,116,578	74,921,001	21,133,841	43,835,968	28,346,697	8,140,435	1,203,487	4,837,530	32,790,320	3,907,298	74,756,123	164,878
	Oct-16	235,225,839	92,575,567	22,465,475	44,451,448	22,044,504	7,481,726	1,203,487	2,240,363	36,296,160	6,467,109	92,449,052	126,515
	Nov-16	259,369,421	102,039,115	23,769,069	44,969,659	32,436,890	7,767,778	1,203,487	661,408	38,466,560	8,055,455	101,830,980	208,135
	Dec-16	357,445,598	165,661,429	31,962,467	54,109,019	27,981,286	7,579,589	1,203,487	801,390	54,737,200	13,409,730	165,450,914	210,515
Total Sales		3,105,059,354	1,231,552,608	297,122,438	561,500,870	314,622,434	95,976,168	14,441,848	42,280,995	471,650,840	75,911,154	1,229,694,514	1,858,094

Fortis BC 2017 COSA

HISTORIC CUSTOMER DEMAND
Schedule 8.2

Measured - kVa	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-16	319,260			119,881	63,367	19,097			92,648	24,266		
Feb-16	325,188			137,072	62,407	16,852			87,437	21,420		
Mar-16	313,862			137,898	64,863	18,241			73,803	19,057		
Apr-16	302,173			131,160	73,982	17,729			61,572	17,729		
May-16	325,265			159,593	79,561	17,564			62,287	6,261		
Jun-16	327,437			143,665	68,305	17,483			88,518	9,465		
Jul-16	305,876			125,429	63,295	17,819			89,460	9,873		
Aug-16	371,218			174,614	78,415	17,854			90,235	10,099		
Sep-16	312,702			144,852	77,067	17,497			62,551	10,735		
Oct-16	277,316			116,545	59,695	17,882			66,828	16,367		
Nov-16	350,269			154,275	81,511	18,057			77,100	19,326		
Dec-16	362,352			141,682	71,405	17,678			103,371	28,216		
Total	3,892,917			1,686,668	843,872	213,753			955,810	192,814		

Individual Load Factor	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-16	26.1%	42.7%	60.1%	60.2%	60.8%	67.1%	63.6%	72.1%	64.0%	26.1%	30.5%
Feb-16	25.7%	43.2%	51.8%	57.6%	78.0%	60.7%	73.2%	73.1%	65.8%	25.7%	25.6%
Mar-16	21.8%	38.3%	49.3%	58.2%	42.6%	52.3%	51.1%	71.0%	58.1%	21.8%	18.7%
Apr-16	18.5%	34.5%	47.8%	54.9%	98.4%	43.1%	41.0%	73.6%	36.3%	18.5%	17.1%
May-16	18.4%	34.6%	42.1%	53.2%	62.6%	34.5%	63.7%	71.9%	19.2%	18.4%	13.0%
Jun-16	19.0%	34.4%	48.2%	55.8%	69.2%	29.8%	53.9%	55.2%	34.1%	19.0%	18.2%
Jul-16	19.9%	35.9%	58.2%	53.2%	55.9%	32.2%	68.3%	58.1%	50.4%	19.9%	19.1%
Aug-16	21.0%	37.7%	45.2%	55.8%	62.6%	39.9%	82.6%	61.2%	49.0%	21.0%	19.2%
Sep-16	17.8%	34.3%	46.6%	56.8%	68.0%	49.0%	53.1%	73.5%	51.1%	17.8%	16.5%
Oct-16	19.3%	35.3%	55.6%	55.2%	59.2%	57.8%	40.3%	73.7%	53.6%	19.3%	18.3%
Nov-16	21.3%	35.8%	42.6%	61.4%	62.9%	65.3%	55.6%	70.0%	58.5%	21.3%	23.2%
Dec-16	28.0%	43.1%	56.2%	58.5%	60.7%	69.1%	67.3%	71.9%	64.5%	28.0%	31.6%
	21.4%	37.5%	50.3%	56.7%	65.1%	50.1%	59.5%	68.8%	50.4%	21.4%	20.9%

Individual NCP (kW)	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
	Power Factor:			90%	90%	95%	100%	100%	99.0%	99.0%		
Jan-16	1,131,843	735,196	91,968	109,512	57,242	18,142	2,412	1,626	91,721	24,023	734,104	1,092
Feb-16	1,081,625	681,262	88,229	127,683	56,166	16,009	2,850	1,657	86,563	21,206	680,320	942
Mar-16	1,038,815	657,105	86,111	122,867	58,376	17,329	3,092	2,004	73,065	18,866	655,542	1,563
Apr-16	1,010,406	623,005	89,436	122,530	66,584	16,843	3,880	9,621	60,957	17,552	621,763	1,241
May-16	976,561	575,908	84,940	142,485	71,604	16,686	4,685	12,391	61,664	6,198	574,042	1,866
Jun-16	1,061,938	635,071	96,999	133,824	61,475	16,609	5,616	15,340	87,633	9,370	633,768	1,303
Jul-16	1,033,109	628,994	96,802	115,483	56,965	16,928	5,030	14,567	88,565	9,774	627,616	1,378
Aug-16	1,070,568	614,799	93,984	155,738	70,574	16,961	4,055	15,126	89,333	9,998	613,531	1,267
Sep-16	977,012	586,024	85,769	130,627	69,360	16,622	3,414	12,642	61,926	10,628	583,958	2,066
Oct-16	1,020,761	662,312	87,597	107,512	53,725	16,988	2,799	7,465	66,160	16,203	660,915	1,397
Nov-16	1,135,900	701,842	97,384	146,485	73,360	17,154	2,561	1,653	76,329	19,133	700,236	1,606
Dec-16	1,251,297	805,671	101,058	129,299	64,264	16,794	2,340	1,600	102,337	27,934	804,606	1,065
Maximum	1,251,297	805,671	101,058	155,738	73,360	18,142	5,616	15,340	102,337	27,934	804,606	2,066
	12,789,834	7,907,188	1,100,276	1,544,045	759,696	203,065	42,734	95,691	946,252	190,886	7,890,403	16,785

Group Coincidence Factor	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-16	41.87%	58.41%	71.73%	72.3%	100.0%	58.4%	41.1%	100.0%	100.0%	41.2%	55.4%
Feb-16	38.05%	59.04%	74.59%	91.9%	100.0%	59.0%	50.9%	100.0%	100.0%	36.7%	51.2%
Mar-16	32.55%	55.89%	71.33%	87.8%	100.0%	55.9%	36.8%	100.0%	100.0%	32.9%	37.8%
Apr-16	28.77%	51.91%	72.01%	86.3%	100.0%	51.9%	50.0%	100.0%	100.0%	27.7%	34.4%
May-16	25.40%	55.35%	74.96%	87.2%	100.0%	55.3%	52.2%	100.0%	100.0%	25.6%	33.3%
Jun-16	38.97%	62.29%	76.28%	89.0%	100.0%	62.3%	58.9%	100.0%	100.0%	37.7%	40.6%
Jul-16	39.37%	63.59%	76.33%	81.3%	100.0%	63.6%	55.6%	100.0%	100.0%	38.5%	44.9%
Aug-16	38.03%	63.70%	75.75%	85.4%	100.0%	63.7%	56.4%	100.0%	100.0%	38.4%	47.2%
Sep-16	26.70%	56.30%	74.15%	86.1%	100.0%	56.3%	53.5%	100.0%	100.0%	26.6%	30.8%
Oct-16	29.89%	52.30%	69.23%	79.3%	100.0%	52.3%	43.6%	100.0%	100.0%	29.2%	33.3%
Nov-16	35.12%	53.44%	71.79%	86.4%	100.0%	53.4%	34.4%	100.0%	100.0%	33.3%	43.6%
Dec-16	41.66%	61.51%	73.98%	77.8%	100.0%	61.5%	41.6%	100.0%	100.0%	41.1%	51.3%
										34%	42%

Rate Class NCP @ Meter (kW)	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-16	307,841	54,527	79,726	41,357	18,142	1,409	669	91,721	24,023	307,236	605
Feb-16	259,227	53,912	98,578	51,625	16,009	1,683	843	86,563	21,206	258,745	482
Mar-16	213,855	47,643	86,771	51,265	17,329	1,728	737	73,065	18,866	213,264	591
Apr-16	179,260	48,186	91,586	57,490	16,843	2,014	4,809	60,957	17,552	178,833	427
May-16	146,309	46,635	105,947	62,439	16,686	2,593	6,462	61,664	6,198	145,687	622
Jun-16	247,502	62,533	105,657	54,713	16,609	3,498	9,038	87,633	9,370	246,974	528
Jul-16	247,606	62,971	90,181	46,287	16,928	3,199	8,099	88,565	9,774	246,988	619
Aug-16	233,779	59,327	116,912	60,271	16,961	2,583	8,538	89,333	9,998	233,181	598
Sep-16	156,471	48,384	97,050	59,753	16,622	1,922	6,759	61,926	10,628	155,833	637
Oct-16	197,943	46,955	76,287	42,582	16,988	1,464	3,254	66,160	16,203	197,479	464
Nov-16	246,460	54,901	110,947	63,390	17,154	1,369	568	76,329	19,133	245,761	700
Dec-16	335,654	63,031	96,999	50,022	16,794	1,439	665	102,337	27,934	335,107	547
Maximum	335,654	63,031	116,912	63,390	18,142	3,498	9,038	102,337	27,934	335,107	700
Winter Peak Month	335,654	63,031	110,947	63,390	18,142	1,683	843	102,337	27,934	335,107	700
Summer Peak Month	247,606	62,971	116,912	62,439	17,329	3,498	9,038	89,333	18,866	246,988	637

Rate Class NCP @ Primary Voltage (kW)		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
	Line Losses:	5.75%	5.75%	5.75%			5.75%	5.75%			5.75%	5.75%
Jan-16		325,542	57,663	84,311	41,357	18,142	1,490	708	91,721	24,023	324,902	640
Feb-16		274,133	57,012	104,246	51,625	16,009	1,779	891	86,563	21,206	273,623	510
Mar-16		226,151	50,383	91,760	51,265	17,329	1,827	779	73,065	18,866	225,527	625
Apr-16		189,567	50,957	96,852	57,490	16,843	2,130	5,086	60,957	17,552	189,116	452
May-16		154,722	49,316	112,039	62,439	16,686	2,742	6,834	61,664	6,198	154,064	658
Jun-16		261,734	66,129	111,732	54,713	16,609	3,699	9,558	87,633	9,370	261,175	559
Jul-16		261,844	66,592	95,366	46,287	16,928	3,382	8,565	88,565	9,774	261,189	654
Aug-16		247,221	62,738	123,634	60,271	16,961	2,731	9,029	89,333	9,998	246,589	632
Sep-16		165,468	51,166	102,630	59,753	16,622	2,032	7,148	61,926	10,628	164,794	674
Oct-16		209,325	49,655	80,674	42,582	16,988	1,548	3,441	66,160	16,203	208,834	491
Nov-16		260,632	58,057	117,326	63,390	17,154	1,447	601	76,329	19,133	259,892	740
Dec-16		354,954	66,655	102,577	50,022	16,794	1,522	703	102,337	27,934	354,376	578
Maximum		354,954	66,655	123,634	63,390	18,142	3,699	9,558	102,337	27,934	354,376	740
Winter Peak Month		354,954	66,655	117,326	63,390	18,142	1,779	891	102,337	27,934	354,376	740
Summer Peak Month		261,844	66,592	123,634	62,439	17,329	3,699	9,558	89,333	18,866	261,189	674

Rate Class NCP @ Input Voltage (kW)		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
	Line Losses:	4.36%	4.36%	4.36%	4.36%	2.86%	4.36%	4.36%	4.36%	2.86%	4.36%	4.36%
Jan-16	672,413	339,719	60,174	87,982	43,159	18,660	1,555	738	95,716	24,709	339,051	668
Feb-16	639,623	286,072	59,495	108,786	53,874	16,466	1,857	930	90,332	21,811	285,539	532
Mar-16	554,026	236,000	52,577	95,756	53,497	17,824	1,907	813	76,247	19,405	235,348	652
Apr-16	518,580	197,823	53,176	101,070	59,994	17,323	2,222	5,307	63,611	18,053	197,352	471
May-16	492,879	161,460	51,464	116,918	65,158	17,162	2,861	7,131	64,349	6,375	160,774	686
Jun-16	647,840	273,132	69,009	116,598	57,096	17,083	3,860	9,974	91,450	9,638	272,549	583
Jul-16	622,916	273,247	69,492	99,519	48,303	17,411	3,530	8,938	92,422	10,053	272,564	683
Aug-16	648,597	257,988	65,471	129,019	62,895	17,446	2,850	9,422	93,223	10,283	257,328	660
Sep-16	497,753	172,674	53,394	107,100	62,356	17,097	2,121	7,459	64,623	10,931	171,970	703
Oct-16	507,268	218,441	51,818	84,187	44,436	17,473	1,616	3,591	69,041	16,666	217,929	512
Nov-16	640,268	271,982	60,586	122,436	66,150	17,644	1,510	627	79,653	19,679	271,210	772
Dec-16	754,335	370,412	69,558	107,044	52,201	17,274	1,588	734	106,794	28,731	369,809	603
Maximum	754,335	370,412	69,558	129,019	66,150	18,660	3,860	9,974	106,794	28,731	369,809	772
Winter Peak Month	7,196,497	370,412	69,558	122,436	66,150	18,660	1,857	930	106,794	28,731	369,809	772
Summer Peak Month		273,247	69,492	129,019	65,158	17,824	3,860	9,974	93,223	19,405	272,564	703

System Coincidence Factor	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-16	98.17%	79.39%	79.08%	85.03%	87.75%	100.00%	77.8%	97.99%	100.00%	96.78%	66.06%
Feb-16	94.82%	78.76%	84.87%	85.03%	88.06%	100.00%	74.8%	93.45%	92.07%	91.65%	74.94%
Mar-16	98.92%	79.72%	85.75%	85.03%	87.86%	100.00%	59.6%	97.95%	99.52%	100.00%	69.39%
Apr-16	86.08%	75.85%	87.56%	91.04%	80.66%	100.00%	76.0%	82.38%	40.47%	82.99%	59.02%
May-16	95.98%	70.17%	80.92%	89.01%	92.37%		89.8%	70.59%	20.42%	96.94%	53.19%
Jun-16	103.44%	72.07%	83.91%	88.72%	92.96%		89.8%	87.48%	30.88%	100.00%	73.94%
Jul-16	100.55%	77.72%	87.90%	89.75%	95.18%		85.6%	92.91%	59.48%	98.31%	91.47%
Aug-16	98.94%	75.23%	86.35%	94.27%	97.38%		92.4%	90.53%	56.11%	99.86%	90.04%
Sep-16	77.03%	99.46%	96.13%	83.67%	53.24%		90.8%	84.83%	35.09%	77.04%	37.04%
Oct-16	99.19%	76.51%	83.96%	88.36%	55.21%	100.00%	45.5%	94.62%	74.00%	96.82%	79.21%
Nov-16	96.84%	72.01%	70.11%	53.26%	80.67%	100.00%	51.6%	88.44%	47.12%	91.84%	79.14%
Dec-16	97.76%	84.33%	87.91%	87.21%	87.93%	100.00%	80.6%	97.33%	96.00%	96.44%	83.39%
							76.19%	89.88%		94%	71%

Coincident Peak (CP) @ Input (kW)	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-16	626,318	333,504	48,488	70,621	36,699	16,374	1,555	575	93,792	24,709	333,063	441
Feb-16	582,672	271,258	48,496	95,562	45,811	14,500	1,857	696	84,412	20,081	270,859	399
Mar-16	513,773	233,447	41,494	81,294	45,491	15,660	1,907	484	74,685	19,311	232,995	452
Apr-16	438,566	170,280	41,865	91,863	54,620	13,973	2,222	4,035	52,401	7,305	170,002	278
May-16	411,628	154,966	35,824	93,852	57,999	15,853		6,405	45,427	1,302	154,601	365
Jun-16	593,719	282,519	51,476	101,259	50,656	15,881		8,954	79,998	2,976	282,088	431
Jul-16	578,916	274,741	55,251	89,491	43,352	16,573		7,655	85,873	5,980	274,116	625
Aug-16	589,611	255,249	48,812	110,399	59,292	16,989		8,704	84,394	5,770	254,655	594
Sep-16	416,080	133,007	53,214	103,156	52,176	9,102		6,770	54,819	3,836	132,746	261
Oct-16	459,584	216,672	40,634	72,454	39,265	9,647	1,616	1,634	65,329	12,332	216,266	406
Nov-16	531,003	263,395	46,024	90,567	35,230	14,233	1,510	323	70,446	9,273	262,784	611
Dec-16	711,447	362,124	59,480	95,423	45,524	15,189	1,588	591	103,945	27,582	361,621	503
Total	6,453,317	2,951,164	571,059	1,095,941	566,116	173,975	12,255	46,827	895,521	140,458	2,945,797	5,366
Peak Month	711,447	362,124	59,480	95,423	45,524	15,189	1,588	591	103,945	27,582	361,621	503
Winter Peak Month	711,447	362,124	59,480	95,562	45,811	16,374	1,907	696	103,945	27,582	361,621	611
Summer Peak Month	593,719	282,519	55,251	110,399	59,292	16,989	2,222	8,954	85,873	12,332	282,088	625

Fortis BC 2017 COSA

HISTORIC kWh AT INPUT
Schedule 8.3

kWh @ Input Voltage		Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
	Jan-16	343,452,641	156,306,736	32,056,930	54,448,907	26,797,750	8,444,743	1,338,770	855,638	51,420,900	11,782,266	156,053,118	253,618
	Feb-16	296,392,122	130,728,717	28,480,634	49,434,147	22,736,233	8,633,621	1,338,770	938,981	44,451,754	9,649,265	130,558,929	169,788
	Mar-16	280,614,859	119,840,808	27,601,073	50,169,880	26,425,734	5,659,099	1,338,770	847,987	40,332,145	8,399,364	119,631,483	209,325
	Apr-16	242,444,848	88,896,473	23,812,696	46,952,756	27,495,182	12,287,858	1,338,770	3,160,866	33,777,322	4,722,923	88,774,023	122,451
	May-16	243,102,548	88,033,969	24,545,904	49,637,030	29,626,445	7,997,460	1,338,770	6,528,796	34,481,510	912,665	87,898,555	135,415
	Jun-16	251,863,157	93,290,769	25,828,434	51,687,961	25,804,108	8,512,698	1,338,770	6,618,158	36,413,320	2,368,939	93,165,327	125,442
	Jul-16	269,184,504	101,229,092	28,078,044	55,651,549	23,588,620	7,246,220	1,338,770	8,236,141	40,039,981	3,776,085	101,093,678	135,415
	Aug-16	292,101,322	107,546,393	29,621,410	58,208,631	30,619,197	8,135,424	1,338,770	10,346,449	42,529,772	3,755,277	107,420,744	125,649
	Sep-16	238,658,438	83,342,790	23,509,474	48,763,522	29,637,406	8,379,675	1,338,770	5,381,312	34,283,360	4,022,130	83,159,378	183,412
	Oct-16	256,607,704	102,981,887	24,990,794	49,448,187	23,048,256	7,701,607	1,338,770	2,492,200	37,948,832	6,657,171	102,841,150	140,736
	Nov-16	282,469,479	113,509,222	26,440,924	50,024,650	33,913,838	7,996,066	1,338,770	735,756	40,218,056	8,292,197	113,277,690	231,531
	Dec-16	390,351,264	184,283,252	35,555,334	60,191,355	29,255,357	7,802,346	1,338,770	891,474	57,229,547	13,803,829	184,049,073	234,179
Total Purchases - Bottom Up		3,387,242,885	1,369,990,108	330,521,651	624,618,577	328,948,125	98,796,817	16,065,240	47,033,756	493,126,499	78,142,111	1,367,923,148	2,066,960

Historic Load Reconciliation	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Secondary Line Losses		5.75%	5.75%	5.75%			5.75%	5.75%			5.75%	5.75%
Primary Line Losses		4.36%	4.36%	4.36%	4.36%	2.86%	4.36%	4.36%	4.36%	2.86%	4.36%	4.36%
	-8.3%	10.11%										

	Actual Gross Energy MWh	Bottom-Up Energy MWh	*% Difference*
Total	3,387,199	3,387,243	0.00%
Jan-16	346,238	343,453	0.81%
Feb-16	298,431	296,392	0.69%
Mar-16	283,811	280,615	1.14%
Apr-16	245,286	242,445	1.17%
May-16	241,860	243,103	-0.51%
Jun-16	251,764	251,863	-0.04%
Jul-16	267,049	269,185	-0.79%
Aug-16	284,258	292,101	-2.69%
Sep-16	235,688	238,658	-1.24%
Oct-16	264,873	256,608	3.22%
Nov-16	281,259	282,469	-0.43%
Dec-16	386,682	390,351	-0.94%

	Actual Gross System Peak MW	CP @ Input Demand kW	*% Difference*	GCF Adjustment Factor	SCF Adjustment Factor
Total	6,453	6,453	0.00%		
Jan-16	625	626	-0.2%	101.5%	101.5%
Feb-16	583	583	0.1%	103.5%	103.5%
Mar-16	514	514	0.0%	99.0%	99.0%
Apr-16	438	439	-0.1%	103.8%	103.8%
May-16	412	412	0.1%	99.2%	99.2%
Jun-16	594	594	0.0%	103.5%	103.5%
Jul-16	579	579	0.0%	102.3%	102.3%
Aug-16	590	590	0.1%	99.1%	99.1%
Sep-16	416	416	0.0%	100.2%	100.2%
Oct-16	459	460	-0.1%	102.5%	102.5%
Nov-16	531	531	0.0%	105.5%	105.5%
Dec-16	712	711	0.1%	101.4%	101.4%

Fortis BC 2017 COSA

FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.4

Number of Customers / Services	Total	Residential	Small General Service	General Service	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Wholesale Primary	Wholesale Transmission	Residential w/o Net Metering	Net Metering
Jan-17	124,886	107,679	12,952	1,513	46	4	1,590	1,095	5	1	107,525	155
Feb-17	136,023	117,632	13,792	1,858	46	4	1,590	1,095	5	1	117,494	138
Mar-17	136,255	117,685	13,974	1,856	46	4	1,590	1,095	5	1	117,530	155
Apr-17	133,617	115,231	14,202	1,443	46	4	1,590	1,095	5	1	115,107	125
May-17	136,780	117,922	14,378	1,740	46	4	1,590	1,095	5	1	117,781	141
Jun-17	129,233	111,172	13,851	1,470	46	4	1,590	1,095	5	1	111,020	152
Jul-17	133,657	115,747	13,934	1,234	46	4	1,590	1,095	5	1	115,566	182
Aug-17	138,258	119,456	14,325	1,736	46	4	1,590	1,095	5	1	119,270	186
Sep-17	132,809	114,658	13,953	1,458	46	4	1,590	1,095	5	1	114,481	177
Oct-17	133,277	115,503	13,796	1,237	46	4	1,590	1,095	5	1	115,330	173
Nov-17	136,260	117,541	14,254	1,724	46	4	1,590	1,095	5	1	117,309	233
Dec-17	135,180	116,914	14,064	1,462	46	4	1,590	1,095	5	1	116,677	237
Total Average	133,853	115,595	13,956	1,561	46	4	1,590	1,095	5	1	115,424	171
		86%										

Historic Energy, Demand And Customer Count
Historic Year

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Input Recorded Data												
Energy Sales (kWh)	3,282,317,076	1,353,778,140	304,323,499	575,109,408	311,098,688	95,976,168	14,441,848	40,288,397	505,880,576	81,420,354		
Total Billing Capacity (kVa)												
Avg. Monthly Billing Capacity (kVa)												
Number of Customers	249,448	115,595	13,956	1,561	46	4	1,590	1,095	5	1	115,424	171
Ratio of NCP to Avg. Billing Capacity												
Rate Classes NCP Demand at Meter	#DIV/0!	368,982	64,558	119,886	62,680	18,142	3,498	8,612	109,764	29,961		
Estimated Based on Recorded Data												
Annual NCP Load Factor	#DIV/0!	42%	54%	55%	57%	60%	47%	53%	52%	31%		
Rate Classes CP Demand at Input Voltage	#DIV/0!	362,124	59,480	95,423	45,524	15,189	1,588	591	103,945	27,582		
Annual CP Load Factor	#DIV/0!	39%	57%	67%	79%	72%	104%	814%	52%	31%		

Customer Information	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Weighting Factors for:												
Points of Delivery per Customer		1.0	1.0	1.0	1.0	1.0	1.0	1.0	2.4	3.0	1	1
Customers Meters & Services		$ 45.55	$ 137.04	$ 213.87	$ 1,055.38	$ 96,100.00	$ -	$ 45.55	$ 41,600.00	$ 41,600.00	45.6	91.1
Customer Retail		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Customer Accounting/Metering		1.000	1.000	1.000	202.500	202.500	1.400	1.400	159.700	159.700	1.00	2.00
Weighted Number of Customers												
Customers (PODs)	249,457	115,595	13,956	1,561	46	4	1,590	1,095	12	3	115,424	171
Customers Meters & Services	13,891,688	5,265,352	1,912,541	333,834	48,547	384,400	-	49,877	499,200	124,800	5,257,569	15,567
Customer Retail	249,457	115,595	13,956	1,561	46	4	1,590	1,095	12	3	115,424	171
Customer Accounting/Metering	263,157	115,595	13,956	1,561	9,315	810	2,226	1,533	1,916	479	115,424	342
Provided Services												
Power Purchased from Utility*		1	1	1	1	1	1	1	1	1	1	1
Reg & Shaping from Utility*		1	1	1	1	1	1	1	1	1	1	1
Uses Utility Transmission*		1	1	1	1	1	1	1	1	1	1	1
Uses Primary Distribution*		1	1	1	1		1	1	1		1	1
Uses Secondary Distribution*		1	1	1			1	1			1	1

* (yes=1,no=0)

Load Data And Customer Sales by Rate Class

kWh Sales at the Meter		Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
	Jan-17	334,623,699	154,463,478	29,516,000	50,133,121	25,343,646	8,203,646	1,203,487	732,926	52,750,835	12,276,559	154,121,493	341,985
	Feb-17	288,463,801	129,171,817	26,223,172	45,515,846	21,502,516	8,387,132	1,203,487	804,317	45,601,441	10,054,074	128,942,871	228,947
	Mar-17	272,585,762	118,432,944	25,413,328	46,193,262	24,991,816	5,497,532	1,203,487	726,372	41,375,283	8,751,737	118,150,685	282,260
	Apr-17	234,419,962	87,840,294	21,925,230	43,231,138	26,003,234	11,937,039	1,203,487	2,707,550	34,650,929	4,921,061	87,675,178	165,116
	May-17	234,204,331	86,993,143	22,600,321	45,702,648	28,018,850	7,769,132	1,203,487	5,592,467	35,373,329	950,953	86,810,547	182,597
	Jun-17	242,922,992	92,181,276	23,781,193	47,591,016	24,403,921	8,269,660	1,203,487	5,669,013	37,355,103	2,468,322	92,012,127	169,149
	Jul-17	259,734,363	100,024,937	25,852,493	51,240,438	22,308,651	7,039,341	1,203,487	7,054,952	41,075,563	3,934,501	99,842,341	182,597
	Aug-17	281,598,440	106,260,518	27,273,526	53,594,838	28,957,733	7,903,158	1,203,487	8,862,610	43,629,749	3,912,820	106,091,090	169,428
	Sep-17	230,265,377	82,377,349	21,646,041	44,898,377	28,029,216	8,140,435	1,203,487	4,609,549	35,170,055	4,190,867	82,130,032	247,317
	Oct-17	248,781,062	101,757,955	23,009,948	45,528,774	21,797,607	7,481,726	1,203,487	2,134,780	38,930,329	6,936,455	101,568,183	189,773
	Nov-17	274,165,842	112,187,742	24,345,136	46,059,544	32,073,599	7,767,778	1,203,487	630,238	41,258,244	8,640,074	111,875,539	312,203
	Dec-17	380,551,445	182,086,687	32,737,110	55,420,405	27,667,898	7,579,589	1,203,487	763,623	58,709,715	14,382,932	181,770,914	315,773
Total Sales		3,282,317,076	1,353,778,140	304,323,499	575,109,408	311,098,688	95,976,168	14,441,848	40,288,397	505,880,576	81,420,354	1,350,990,999	2,787,141
		3,107,000,000											
		4.9%	106%	100.7%	133,853	120%	102.3%	24,522	27,763	88%	1.5%		

Fortis BC 2017 COSA

FORECAST CUSTOMER DEMAND
Schedule 8.5

Measured - kVa	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-17												
Feb-17												
Mar-17												
Apr-17												
May-17												
Jun-17												
Jul-17												
Aug-17												
Sep-17												
Oct-17												
Nov-17												
Dec-17												
Total												

Individual Load Factor	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-17	26.1%	42.7%	60.1%	60.2%	60.8%	67.1%	63.6%	72.1%	64.0%	26.1%	30.5%
Feb-17	25.7%	43.2%	51.8%	57.6%	78.0%	60.7%	73.2%	73.1%	65.8%	25.7%	25.6%
Mar-17	21.8%	38.3%	49.3%	58.2%	42.6%	52.3%	51.1%	71.0%	58.1%	21.8%	18.7%
Apr-17	18.5%	34.5%	47.8%	54.9%	98.4%	43.1%	41.0%	73.6%	36.3%	18.5%	17.1%
May-17	18.4%	34.6%	42.1%	53.2%	62.6%	34.5%	63.7%	71.9%	19.2%	18.4%	13.0%
Jun-17	19.0%	34.4%	48.2%	55.8%	69.2%	29.8%	53.9%	55.2%	34.1%	19.0%	18.2%
Jul-17	19.9%	35.9%	58.2%	53.2%	55.9%	32.2%	68.3%	58.1%	50.4%	19.9%	19.1%
Aug-17	21.0%	37.7%	45.2%	55.8%	62.6%	39.9%	82.6%	61.2%	49.0%	21.0%	19.2%
Sep-17	17.8%	34.3%	46.6%	56.8%	68.0%	49.0%	53.1%	73.5%	51.1%	17.8%	16.5%
Oct-17	19.3%	35.3%	55.6%	55.2%	59.2%	57.8%	40.3%	73.7%	53.6%	19.3%	18.3%
Nov-17	21.3%	35.8%	42.6%	61.4%	62.9%	65.3%	55.6%	70.0%	58.5%	21.3%	23.2%
Dec-17	28.0%	43.1%	56.2%	58.5%	60.7%	69.1%	67.3%	71.9%	64.5%	28.0%	31.6%
	21.4%	37%	50%	57%	65%	50%	59%	69%	50%	21.4%	20.9%

Individual NCP (kW)	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
	Power Factor:		100%	100%	90%	95%	100%	100%	99.0%			
Jan-17	1,219,048	808,154	94,197	113,848	56,601	18,142	2,412	1,550	98,378	25,767	806,516	1,638
Feb-17	1,196,206	775,533	93,595	135,354	55,537	16,009	2,952	1,635	92,845	22,745	774,120	1,413
Mar-17	1,113,989	722,548	88,198	124,587	57,722	17,329	3,092	1,909	78,367	20,236	720,204	2,344
Apr-17	1,086,762	684,956	91,604	130,268	65,838	16,843	3,880	9,167	65,381	18,826	683,094	1,862
May-17	1,042,000	633,464	86,998	144,771	70,803	16,686	4,685	11,807	66,139	6,648	630,666	2,798
Jun-17	1,141,124	698,237	99,350	141,865	60,786	16,609	5,616	14,617	93,993	10,050	696,283	1,954
Jul-17	1,109,383	691,591	99,148	121,002	56,327	16,928	5,030	13,880	94,993	10,484	689,524	2,068
Aug-17	1,142,042	675,951	96,262	158,077	69,783	16,961	4,055	14,413	95,816	10,724	674,049	1,901
Sep-17	1,045,052	644,659	87,847	134,061	68,584	16,622	3,414	12,047	66,420	11,399	641,560	3,099
Oct-17	1,099,157	728,202	89,720	112,871	53,123	16,988	2,799	7,113	70,961	17,379	726,107	2,095
Nov-17	1,225,965	771,716	99,744	158,287	72,538	17,154	2,561	1,575	81,868	20,521	769,307	2,409
Dec-17	1,347,292	885,569	103,508	134,287	63,545	16,794	2,340	1,524	109,764	29,961	883,972	1,597

Maximum	1,347,292	885,569	103,508	158,287	72,538	18,142	5,616	14,617	109,764	29,961	883,972	3,099
Total	13,768,020	8,720,580	1,130,170	1,609,278	751,188	203,065	42,836	91,238	1,014,925	204,739	8,695,402	25,178

Group Coincidence Factor	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-17	41.87%	58.41%	71.73%	72.25%	100.00%	58.41%	41.14%	100.00%	100.00%	41.23%	55.43%
Feb-17	38.05%	59.04%	74.59%	91.92%	100.00%	59.04%	50.85%	100.00%	100.00%	36.75%	51.19%
Mar-17	32.55%	55.89%	71.33%	87.82%	100.00%	55.89%	36.76%	100.00%	100.00%	32.86%	37.80%
Apr-17	28.77%	51.91%	72.01%	86.34%	100.00%	51.91%	49.99%	100.00%	100.00%	27.71%	34.41%
May-17	25.40%	55.35%	74.96%	87.20%	100.00%	55.35%	52.15%	100.00%	100.00%	25.58%	33.33%
Jun-17	38.97%	62.29%	76.28%	89.00%	100.00%	62.29%	58.92%	100.00%	100.00%	37.65%	40.57%
Jul-17	39.37%	63.59%	76.33%	81.25%	100.00%	63.59%	55.60%	100.00%	100.00%	38.47%	44.89%
Aug-17	38.03%	63.70%	75.75%	85.40%	100.00%	63.70%	56.45%	100.00%	100.00%	38.35%	47.17%
Sep-17	26.70%	56.30%	74.15%	86.15%	100.00%	56.30%	53.46%	100.00%	100.00%	26.63%	30.85%
Oct-17	29.89%	52.30%	69.23%	79.26%	100.00%	52.30%	43.59%	100.00%	100.00%	29.15%	33.25%
Nov-17	35.12%	53.44%	71.79%	86.41%	100.00%	53.44%	34.39%	100.00%	100.00%	33.27%	43.59%
Dec-17	41.66%	61.51%	73.98%	77.84%	100.00%	61.51%	41.58%	100.00%	100.00%	41.07%	51.34%
										34.1%	42.0%

Rate Class NCP @ Meter (kW)	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-17	338,449	55,849	82,883	40,894	18,142	1,409	638	98,378	25,767	337,541	908
Feb-17	295,144	57,191	104,501	51,047	16,009	1,743	832	92,845	22,745	294,420	723
Mar-17	235,186	48,798	87,985	50,690	17,329	1,728	702	78,367	20,236	234,300	886
Apr-17	197,114	49,354	97,370	56,846	16,843	2,014	4,582	65,381	18,826	196,473	641
May-17	160,990	47,765	107,647	61,739	16,686	2,593	6,158	66,139	6,648	160,058	933
Jun-17	272,128	64,049	112,005	54,101	16,609	3,498	8,612	93,993	10,050	271,335	793
Jul-17	272,278	64,497	94,491	45,769	16,928	3,199	7,718	94,993	10,484	271,350	928
Aug-17	257,079	60,765	118,668	59,596	16,961	2,583	8,136	95,816	10,724	256,182	897
Sep-17	172,161	49,556	99,601	59,084	16,622	1,922	6,441	66,420	11,399	171,204	956
Oct-17	217,655	48,093	80,089	42,105	16,988	1,464	3,100	70,961	17,379	216,958	697
Nov-17	271,052	56,231	119,886	62,680	17,154	1,369	542	81,868	20,521	270,002	1,050
Dec-17	368,982	64,558	100,741	49,462	16,794	1,439	634	109,764	29,961	368,162	820
Maximum	368,982	64,558	119,886	62,680	18,142	3,498	8,612	109,764	29,961	368,162	1,050
Winter Peak Month	368,982	64,558	119,886	62,680	18,142	1,743	832	109,764	29,961	368,162	1,050
Summer Peak Month	272,278	64,497	118,668	61,739	17,329	3,498	8,612	95,816	20,236	271,350	956

Rate Class NCP @ Primary Voltage (kW)	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Line Losses:	5.75%	5.75%	5.75%			5.75%	5.75%			5.75%	5.75%
Jan-17	357,910	59,060	87,649	40,894	18,142	1,490	674	98,378	25,767	356,950	960
Feb-17	312,114	60,479	110,510	51,047	16,009	1,843	880	92,845	22,745	311,349	765
Mar-17	248,710	51,604	93,044	50,690	17,329	1,827	742	78,367	20,236	247,773	937
Apr-17	208,448	52,192	102,969	56,846	16,843	2,130	4,846	65,381	18,826	207,770	678
May-17	170,247	50,511	113,836	61,739	16,686	2,742	6,512	66,139	6,648	169,261	986
Jun-17	287,775	67,732	118,446	54,101	16,609	3,699	9,107	93,993	10,050	286,937	838
Jul-17	287,934	68,205	99,924	45,769	16,928	3,382	8,161	94,993	10,484	286,953	981
Aug-17	271,861	64,259	125,491	59,596	16,961	2,731	8,604	95,816	10,724	270,913	948
Sep-17	182,060	52,406	105,328	59,084	16,622	2,032	6,811	66,420	11,399	181,049	1,011
Oct-17	230,170	50,858	84,695	42,105	16,988	1,548	3,279	70,961	17,379	229,433	737
Nov-17	286,638	59,464	126,779	62,680	17,154	1,447	573	81,868	20,521	285,527	1,110
Dec-17	390,198	68,270	106,533	49,462	16,794	1,522	670	109,764	29,961	389,331	867
Maximum	390,198	68,270	126,779	62,680	18,142	3,699	9,107	109,764	29,961	389,331	1,110
Winter Peak Month	390,198	68,270	126,779	62,680	18,142	1,843	880	109,764	29,961	389,331	1,110

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Summer Peak Month		287,934	68,205	125,491	61,739	17,329	3,699	9,107	95,816	20,236	286,953	1,011

Rate Class NCP @ Input Voltage (kW)		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
	Line Losses:	4.36%	4.36%	4.36%	4.36%	2.86%	4.36%	4.36%	4.36%	2.86%	4.36%	4.36%
Jan-17	719,354	373,497	61,632	91,466	42,675	18,660	1,555	704	102,662	26,502	372,495	1,002
Feb-17	697,003	325,707	63,113	115,322	53,270	16,466	1,923	918	96,888	23,394	324,909	798
Mar-17	586,485	259,541	53,851	97,096	52,898	17,824	1,907	775	81,780	20,813	258,563	978
Apr-17	550,959	217,525	54,464	107,453	59,322	17,323	2,222	5,057	68,228	19,363	216,818	707
May-17	516,270	177,662	52,711	118,794	64,428	17,162	2,861	6,795	69,019	6,838	176,632	1,029
Jun-17	689,921	300,308	70,681	123,604	56,457	17,083	3,860	9,504	98,086	10,337	299,433	875
Jul-17	663,058	300,474	71,176	104,276	47,762	17,411	3,530	8,517	99,130	10,783	299,450	1,024
Aug-17	684,198	283,701	67,057	130,956	62,191	17,446	2,850	8,978	99,989	11,030	282,711	990
Sep-17	523,611	189,988	54,688	109,915	61,657	17,097	2,121	7,107	69,313	11,724	188,933	1,055
Oct-17	540,025	240,194	53,073	88,383	43,938	17,473	1,616	3,421	74,052	17,875	239,425	769
Nov-17	685,178	299,121	62,054	132,301	65,409	17,644	1,510	598	85,434	21,107	297,962	1,159
Dec-17	806,146	407,191	71,243	111,173	51,616	17,274	1,588	699	114,544	30,817	406,286	905
Maximum	806,146	407,191	71,243	132,301	65,409	18,660	3,860	9,504	114,544	30,817	406,286	1,159
Winter Peak Month	7,662,207	407,191	71,243	132,301	65,409	18,660	1,923	918	114,544	30,817	406,286	1,159
Summer Peak Month		300,474	71,176	130,956	64,428	17,824	3,860	9,504	99,989	20,813	299,450	1,055

System Coincidence Factor	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-17	98.17%	79.39%	79.08%	85.03%	87.75%	100.00%	77.85%	97.99%	100.00%	96.78%	66.06%
Feb-17	94.82%	78.76%	84.87%	85.03%	88.06%	100.00%	74.79%	93.45%	92.07%	91.65%	74.94%
Mar-17	98.92%	79.72%	85.75%	85.03%	87.86%	100.00%	59.58%	97.95%	99.52%	100.00%	69.39%
Apr-17	86.08%	75.85%	87.56%	91.04%	80.66%	100.00%	76.02%	82.38%	40.47%	82.99%	59.02%
May-17	95.98%	70.17%	80.92%	89.01%	92.37%		89.82%	70.59%	20.42%	96.94%	53.19%
Jun-17	103.44%	72.07%	83.91%	88.72%	92.96%		89.77%	87.48%	30.88%	100.00%	73.94%
Jul-17	100.55%	77.72%	87.90%	89.75%	95.18%		85.65%	92.91%	59.48%	98.31%	91.47%
Aug-17	98.94%	75.23%	86.35%	94.27%	97.38%		92.38%	90.53%	56.11%	99.86%	90.04%
Sep-17	77.03%	99.46%	96.13%	83.67%	53.24%		90.77%	84.83%	35.09%	77.04%	37.04%
Oct-17	99.19%	76.51%	83.96%	88.36%	55.21%	100.00%	45.51%	94.62%	74.00%	96.82%	79.21%
Nov-17	96.84%	72.01%	70.11%	53.26%	80.67%	100.00%	51.56%	88.44%	47.12%	91.84%	79.14%
Dec-17	97.76%	84.33%	87.91%	87.21%	87.93%	100.00%	80.55%	97.33%	96.00%	96.44%	83.39%
										94.1%	71.4%

Coincident Peak (CP) @ Input (kW)	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-17	671,526	366,578	49,664	73,418	36,288	16,374	1,555	548	100,598	26,502	365,916	662
Feb-17	636,036	308,802	51,445	101,304	45,298	14,500	1,923	686	90,539	21,538	308,204	598
Mar-17	545,414	256,656	42,499	82,431	44,981	15,660	1,907	462	80,105	20,713	255,978	679
Apr-17	465,822	187,189	42,880	97,665	54,009	13,973	2,222	3,844	56,204	7,835	186,771	417
May-17	431,874	170,399	36,692	95,357	57,350	15,853		6,103	48,724	1,397	169,851	548
Jun-17	634,124	310,560	52,724	107,343	50,089	15,881		8,532	85,803	3,192	309,913	647
Jul-17	617,703	302,092	56,591	93,768	42,867	16,573		7,294	92,105	6,414	301,155	937
Aug-17	623,337	280,665	49,995	112,057	58,628	16,989		8,294	90,519	6,188	279,774	891
Sep-17	436,659	146,231	54,503	105,867	51,591	9,102		6,451	58,798	4,114	145,841	391
Oct-17	490,834	238,207	41,619	76,065	38,826	9,647	1,616	1,557	70,070	13,227	237,599	609
Nov-17	571,018	289,621	47,140	97,864	34,836	14,233	1,510	308	75,559	9,946	288,705	917
Dec-17	761,499	398,046	60,922	99,104	45,014	15,189	1,588	563	111,489	29,584	397,291	755
Total	6,885,846	3,255,047	586,673	1,142,244	559,776	173,975	12,322	44,644	960,513	150,652	3,246,997	8,049
Peak Month	761,499	362,124	59,480	95,423	45,524	15,189	1,588	591	103,945	27,582	#DIV/0!	#DIV/0!
Winter Peak Month		398,046	60,922	101,304	45,298	16,374	1,923	686	111,489	29,584	397,291	917
Summer Peak Month		310,560	56,591	112,057	58,628	16,989	2,222	8,532	92,105	13,227	309,913	937

Contract Demand Limit (kW)		Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
	Jan-17												
	Feb-17												
	Mar-17												
	Apr-17												
	May-17												
	Jun-17												
	Jul-17												
	Aug-17												
	Sep-17												
	Oct-17												
	Nov-17												
	Dec-17												
Total													

CP (kW) Net Amount		Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
	Jan-17	671,473	366,525	49,664	73,418	36,288	16,374	1,555	548	100,598	26,502	365,916	609
	Feb-17	635,982	308,749	51,445	101,304	45,298	14,500	1,923	686	90,539	21,538	308,204	545
	Mar-17	545,323	256,565	42,499	82,431	44,981	15,660	1,907	462	80,105	20,713	255,978	587
	Apr-17	465,705	187,072	42,880	97,665	54,009	13,973	2,222	3,844	56,204	7,835	186,771	300
	May-17	431,696	170,220	36,692	95,357	57,350	15,853		6,103	48,724	1,397	169,851	369
	Jun-17	633,903	310,339	52,724	107,343	50,089	15,881		8,532	85,803	3,192	309,913	426
	Jul-17	617,349	301,739	56,591	93,768	42,867	16,573		7,294	92,105	6,414	301,155	584
	Aug-17	623,002	280,330	49,995	112,057	58,628	16,989		8,294	90,519	6,188	279,774	556
	Sep-17	436,531	146,104	54,503	105,867	51,591	9,102		6,451	58,798	4,114	145,841	263
	Oct-17	490,631	238,004	41,619	76,065	38,826	9,647	1,616	1,557	70,070	13,227	237,599	406
	Nov-17	570,813	289,417	47,140	97,864	34,836	14,233	1,510	308	75,559	9,946	288,705	712
	Dec-17	761,379	397,925	60,922	99,104	45,014	15,189	1,588	563	111,489	29,584	397,291	634
Total		6,883,787	3,252,988	586,673	1,142,244	559,776	173,975	12,322	44,644	960,513	150,652	3,246,997	5,991
Peak Month		761,379	397,925	60,922	112,057	58,628	16,989	2,222	8,532	111,489	29,584	397,291	712
Winter Peak Month		761,379	397,925	60,922	101,304	54,009	16,374	2,222	3,844	111,489	29,584	397,291	712
Summer Peak Month		633,903	310,339	56,591	112,057	58,628	16,989		8,532	92,105	6,414	309,913	584

Fortis BC 2017 COSA

FORECAST kWh AT INPUT
Schedule 8.6

kWh @ Input Voltage		Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
	Jan-17	365,315,481	171,826,551	32,833,862	55,768,531	26,497,617	8,444,743	1,338,770	815,314	55,152,737	12,637,356	171,446,124	380,427
	Feb-17	314,871,078	143,691,882	29,170,891	50,632,233	22,481,589	8,633,621	1,338,770	894,729	47,677,809	10,349,553	143,437,200	254,682
	Mar-17	297,605,497	131,745,864	28,270,012	51,385,797	26,129,768	5,659,099	1,338,770	808,023	43,259,223	9,008,942	131,431,876	313,988
	Apr-17	255,314,994	97,714,326	24,389,821	48,090,704	27,187,238	12,287,858	1,338,770	3,011,902	36,228,688	5,065,686	97,530,650	183,676
	May-17	255,567,634	96,771,949	25,140,799	50,840,034	29,294,631	7,997,460	1,338,770	6,221,110	36,983,982	978,901	96,568,827	203,122
	Jun-17	265,208,044	102,543,274	26,454,412	52,940,671	25,515,104	8,512,698	1,338,770	6,306,261	39,055,992	2,540,863	102,355,111	188,163
	Jul-17	283,780,896	111,268,632	28,758,544	57,000,320	23,324,430	7,246,220	1,338,770	7,847,992	42,945,855	4,050,132	111,065,510	203,122
	Aug-17	307,417,298	118,205,149	30,339,314	59,619,376	30,276,264	8,135,424	1,338,770	9,858,846	45,616,341	4,027,814	118,016,675	188,473
	Sep-17	250,899,005	91,637,297	24,079,249	49,945,355	29,305,469	8,379,675	1,338,770	5,127,704	36,771,452	4,314,033	91,362,180	275,118
	Oct-17	271,488,038	113,196,457	25,596,471	50,646,614	22,790,117	7,701,607	1,338,770	2,374,749	40,702,942	7,140,311	112,985,353	211,105
	Nov-17	298,718,214	124,798,645	27,081,746	51,237,048	33,534,005	7,996,066	1,338,770	701,082	43,136,854	8,893,998	124,451,348	347,297
	Dec-17	415,728,912	202,554,855	36,417,053	61,650,153	28,927,699	7,802,346	1,338,770	849,461	61,382,942	14,805,633	202,203,586	351,268
Total Purchases - Bottom Up		3,581,915,090	1,505,954,881	338,532,175	639,756,836	325,263,932	98,796,817	16,065,240	44,817,172	528,914,816	83,813,221	1,502,854,441	3,100,441
		408,894											

Historic Load Reconciliation	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Secondary Line Losses		5.75%	5.75%	5.75%			5.75%	5.75%			5.75%	5.75%
Primary Line Losses		4.36%	4.36%	4.36%	4.36%	2.86%	4.36%	4.36%	4.36%	2.86%	4.36%	4.36%
	-8.33%											

Appendix B – Minimum System Analysis

The minimum system analysis is used to 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. FortisBC staff provided the data necessary to complete the minimum system study using 2017 data. Along with the minimum system results, an offset to account for the peak load carrying capability (PLCC) of a minimum system was incorporated into the analysis.

The minimum system approach reflects 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 concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers use a delivery quantity greater than the minimum unit up to the level of their peak demand, therefore, that portion of the costs should be treated as demand related.

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

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

The following summarize the resulting classification and allocation for the distribution accounts.

- Substations, including land and station equipment. These costs are classified as demand-related as they are sized on the basis of the peak load for the area served. The non-coincident peak at primary (NCPP) is used as the allocation factor.

- Poles, Towers & Fixtures. The results of the minimum system analysis are 81% customer-related and 19% demand-related. The customer-related costs are allocated on the basis of actual customers. The demand-related component is allocated on the basis of the non-coincident peak (NCP) split between primary and secondary plant.

- Conductors & Devices. The results of the minimum system analysis are 65% customer-related and 35% demand-related. The customer-related costs are allocated on the basis of actual customers. The demand-related component is allocated on the basis of the NCP split between primary and secondary.

- Line Transformers. The results of the minimum system analysis are 69% customer-related and31% demand-related. The customer-related costs are allocated on the basis of actual customers. The demand-related component is allocated on the basis of the NCPS.

- Services, Meters and Installation on Customer Premises. These costs are all related to the customer component as they are installed for each customer served. They are allocated on the basis of customers weighted according to the average cost of meters by class.

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

To develop the minimum system percentage splits, FortisBC provided analysis for the poles, conductors and transformer categories. The following provides the technical information provided by staff to calculate the percentage splits for the minimum system analysis.

Poles

FortisBC has a total of 70,382 poles ranging from 35 feet to 70 feet, with both single and three phase configuration. The cost per pole, before overheads, range from $546to $3,164 per pole based on the current purchase price, with installation and material costs, also before overheads, ranging from $899 to $1,243. In the case of poles, it was determined that the size of the poles is a function of the location of the pole rather than the peak load on the system. Because of the diverse topography in the region, the pole size is determined based primarily on the physical requirements at each location rather than the voltage of the line. The minimum pole therefore varies in size but reflects the slightly lower costs associated with a single-phase configuration. The cost of the cross arms, anchor plates and insulators were included in the installed cost of the poles. The difference between the cost of installed poles at single-phase versus the cost for three-phase was determined to be the demand-related portion of pole costs.

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

The following information provides the details associated with the pole analysis.

FortisBC Minimum System Analysis Power Poles					
Pole Size	**Cost**	**# Installed**	**Total Cost**		
35' Single	$1,511.29	14,258	$21,547,733		
40' Single	$1,742.81	7,645	$13,324,388		
40' Three	$2,104.64	7,637	$16,072,377		
45' Single	$1,802.77	17,367	$31,307,866		
45' Three	$2,164.60	16,074	$34,793,024		
50' Single	$1,718.19	2,950	$5,068,005		
50' Three	$2,080.02	4,452	$9,261,041		
55' Single	$2,317.89	563	$1,305,650		
55' Three	$2,679.72	932	$2,496,712		
60' Single	$2,159.60	207	$446,275		
60' Three	$2,521.43	391	$986,767		
65' Single	$2,811.14	86	$241,635		
65' Three	$3,172.97	155	$491,949		
70' Single	$4,391.19	68	$296,609		
70' Three	$4,753.02	47	$225,548		
Total		70,382	$131,374,436		
Minimum System Cost			$106,367,871		
Actual System Cost			$131,374,436		
Customer-Related			81%		
Demand-Related			19%		
Cost per pole calculations (2017, updated from latest workbook)					
	Pole	**Other Material**	**Material Overhead**	**Install Cost**	**Total Cost**
35' Single	$545.91	$117.59	10%	$781.44	$1,511.29
40' Single	$756.38	$117.59	10%	$781.44	$1,742.81
40' Three	$756.38	$293.14	10%	$950.16	$2,104.64
45' Single	$810.89	$117.59	10%	$781.44	$1,802.77
45' Three	$810.89	$293.14	10%	$950.16	$2,164.60
50' Single	$734.00	$117.59	10%	$781.44	$1,718.19
50' Three	$734.00	$293.14	10%	$950.16	$2,080.02
55' Single	$1,279.18	$117.59	10%	$781.44	$2,317.89
55' Three	$1,279.18	$293.14	10%	$950.16	$2,679.72
60' Single	$1,135.28	$117.59	10%	$781.44	$2,159.60
60' Three	$1,135.28	$293.14	10%	$950.16	$2,521.43
65' Single	$1,727.59	$117.59	10%	$781.44	$2,811.14
65' Three	$1,727.59	$293.14	10%	$950.16	$3,172.97
70' Single	$3,164.00	$117.59	10%	$781.44	$4,391.19
70' Three	$3,164.00	$293.14	10%	$950.16	$4,753.02

Minimum					
Minimum = 35' pole, no crossarm					
Material and Installation Costs (2017, updated from latest workbook)					
		Material Cost	Install Labor		
Three Phase Primary Tangent Structure		$212.47	$301.92		
Two Phase Primary Tangent Structure		$170.25	$222.00		
Single Phase Primary Tangent Structure		$36.92	$133.20		
Single Downhaul Guy & Single Plate Anchor (every 3rd pole)		$67.22	$115.44		
Neutral Attachment Tangent		$13.45	$75.48		
Pole Installation Cost			$457.32		
Assumptions from 2017 Study					
Pole cost is based on Class 3 (or equivalent) poles.					
Pole types considered in this study include: Secondary, Overhead Guying, TRD and Primary Distribution.					
All others (Communication, Decommissioned, Other non-electrical, and Streetlight) were not included.					
All Secondary and Overhead Guying poles are categorized as single phase.					
All 35' poles are considered single phase.					
Primary distribution poles with crossarms are categorized as three phase.					
To determine remaining pole phasing, a ratio of single phase conductor to three phase conductor was applied to remaining poles.					
2 phase was counted as 3 phase.					

Conductors

FortisBC has a total of 16,070kilometers of overhead conductor of various size and configuration. The installed cost, before overheads, ranges from $690 to $42,430 per kilometer based on the current purchase price. The minimum sized conductor was determined to be two lines of 2 ACSR, with a loaded cost of $3,015 per kilometer. When this minimum size was applied across all conductors, with an adjustment to comparable single-phase km, the results showed a minimum system cost of $43.8 million compared to an installed cost of $67.3 million. This means that 65% of the costs were related to the minimum size conductor, and were therefore classified as customer-related costs. The remaining 35% was classified as demand-related.

This compares to a 58% customer/42% demand split resulting from the last minimum system study, which was conducted in 2007. This same split was used in the 2009 COSA. In the 1992 study the minimum sized conductor was set at 2 lines of 4 ACSR, which at the time was less costly than 2 ACSR. Current costs for conductor are less variable than in 1992, reflecting the increasing labour component associated with installing conductor.

The following information provides the details associated with the conductor analysis.

FortisBC Minimum System Analysis Conductor							
Conductor Type	**Conductor Length (km)**	**Conductor Cost per 1km**	**Total OH 1ph Length (km)**	**Total OH 3ph Length (km)**	**UG 1ph Cable Segments**	**UG 3ph Cable Segments**	**Total Cost**
927 AL	44	$7,340.00	0.1380	14.5512	0	0	$511,314
477 AL	1,058	$3,360.00	1.6736	352.1334	0	0	$8,136,555
4/0 Al	46	$2,910.00	22.6489	7.7785	0	0	$415,855
336 AL	32	$3,680.00	0.0000	10.7726	0	0	$258,885
397 Al	40	$3,500.00	0.0000	13.2850	0	0	$312,360
3/0 ACSR	440	$1,380.00	0.0383	13.5709	0	0	$783,148
266 ACSR	112	$2,490.00	0.5932	37.0337	0	0	$763,118
1/0 ACSR	91	$770.00	7.3529	2.3790	322	307	$657,858
2/0 ACSR	1,577	$1,540.00	139.1763	480.1455	0	29	$9,806,653
2 ACSR	9,305	$690.00	2,231.3519	1,001.6307	32	32	$28,058,989
4 ACSR	151	$690.00	46.1538	35.5914	0	0	$655,342
90 MCM Cu	148	$2,250.00	5.6930	48.0059	0	0	$707,812
2 CU	1,920	$690.00	4.4138	26.0157	6,631	6,626	$12,129,697
3 CU	41	$690.00	0.6638	13.7013	0	0	$129,278
4 CU	269	$690.00	23.3772	84.7635	10	2	$941,534
6 CU	422	$690.00	135.1817	105.1832	0	0	$1,912,210
8 CU	97	$690.00	50.4485	18.4105	0	0	$525,275
1/0 CU	3	$2,250.00	1.3370	0.5978	1	2	$22,383
3/0 CU	3	$8,330.00	0.0000	0.9903	0	0	$31,706
4/0 CU	74	$4,540.00	14.8590	19.8074	0	0	$573,495
300 CU	1	$13,060.00	0.0000	0.1615	0	0	$7,666
350 Al	142	$13,060.00	0.0000	0.0000	38	745	$3,615,067
500 Al	6	$15,140.00	0.0000	0.0000	0	26	$156,291
750 Al	48	$19,490.00	0.0000	0.0000	0	147	$1,270,381
1000	1	$42,430.00	0.0000	0.0000	0	1	$32,456
Total	16,070		2,685	2,287	7,034	7,917	$67,341,135
Unknown (added to #2)	2,045		241.6219	243.2007	1,840	1,835	
Minimum System Cost							$43,773,950
Actual System Cost							$67,341,135
Customer-Related							65%
Demand-Related							35%

	Measured Length (km)						
	Overhead	**Underground**					
927 AL	14.69	N/A					
477 AL	353.81	N/A					
4/0 Al	30.43	N/A					
336 AL	10.77	N/A					
397 Al	13.29	N/A					
3/0 ACSR	13.61	N/A					
266 ACSR	37.63	N/A					
1/0 ACSR	9.73	76.36					
2/0 ACSR	619.32	4.16					
2 ACSR	3232.98	9.05					
4 ACSR	81.75	N/A					
90 MCM Cu	53.70	N/A					
2 CU	30.43	814.88					
3 CU	14.37	N/A					
4 CU	108.14	0.71					
6 CU	240.36	N/A					
8 CU	68.86	N/A					
1/0 CU	1.93	0.20					
3/0 CU	0.99	N/A					
4/0 CU	34.67	N/A					
300 CU	0.16	N/A					
350 Al	0.00	142.38					
500 Al	0.00	6.32					
750 Al	0.00	47.62					
1000	0.00	0.71					
Total	4971.61	1102.39					
Unknown (added to #2)	484.82	596.33					
Assumptions (2017)							
All three phase lines were assumed to require 3 strands of conductor (+1 neutral strand for OH conductor)							
All two-phase lines were assumed to require 2 strands of conductor (+1 neutral strand for OH conductor)							
All single-phase lines were assumed to require 1 strand of conductor (+1 neutral stand for OH conductor)							
Neutral conductor was assumed as follows:							
- For 927-4/0, assume 3/0 neutral (398.94km)							
- For < 4/0, assume #2 Al neutral (4097.35km)							
All cost information from March 2017 Workbook							
For conductors with ampacity less than #2 ACSR, cost of #2 ACSR was used							
To determine average number of spans per km for 3ph & 1ph overhead:							

Calculate total length of single phase and three phase primary conductor							
Divide total conductor length by total number of single phase and three phase primary poles to obtain average span length							
- This study yields avg. 1ph span length of 62m & avg. 3ph span length of 77m							
Spans per kilometre for each conductor type = total conductor length/avg. span length							
For "Unknown" conductor records, other ArcFM notes and attributes were analyzed.							
It was determined that >80% of "Unknown" overhead conductor was noted as #2 ACSR. As such, these records were added to #2 ACSR totals.							
It was determined that >70% of "Unknown" underground conductor was noted as #2 Cu. As such, these records were added to #2 Cu totals.							
Conductor Cost per Span (2017)							
Overhead							
	Per Span						
Install 1ph prim and neutral #2 ACSR or smaller	$404.04						
Install 1ph prim and neutral larger than #2 ACSR	$497.28						
Install 3ph prim and neutral #2 ACSR or smaller	$541.68						
Install 3ph prim and neutral larger than #2 ACSR	$999.00						
Underground							
	Per Segment						
UG - Primary Conductors - 1 conductor # 2 Cu or 350 Al in 1 duct	$492.84						
UG - Primary Conductors - 3 conductors # 2 Cu in 1-4" duct	$1,105.56						
UG - Primary Conductors - 3 conductors 350 Al in 1-4" duct	$1,363.08						
UG - Primary Conductors - 3 conductors 350 Al or 750 Al in 3-3"ducts	$2,331.00						

Transformers

FortisBC has a total of 37,657 transformers ranging from 10 kVA to 2500 kVA. The installed cost per transformer, before overheads, ranges from $875 to $35,947 per transformer based on the current purchase price. The minimum sized transformer was determined to be a 15-kVA transformer, with a loaded cost of $2,292. While there are a number of transformers within the system at 10 kVA, this size is no longer readily available or routinely installed by FortisBC. When this minimum size was applied across all transformers, the results showed a minimum system cost of $86.3 million compared to an installed cost of $125.6 million. This means that 69% of the costs were related to the minimum size transformer, and were therefore classified as customer-related costs. The remaining 31% was classified as demand-related. This compares to a 73% customer/27% demand split resulting from the last minimum system study, which was conducted in 2007. This same split was used in the 2009 COSA.

The following information provides the details associated with the transformer analysis.

FortisBC Minimum System Analysis Transformers						
Size	**Cost**	**# Installed**	**Total Cost**			
10 KVA	$2,292	1,753	$4,017,688	(includes <10 KVA)		
15 KVA	$2,292	6,124	$14,035,553	(includes 11 KVA)		
25 KVA	$2,438	13,204	$32,194,481	(includes 30 KVA)		
37 KVA	$2,929	826	$2,419,519			
50 KVA	$3,089	7,413	$22,900,610			
75 KVA	$3,970	5,520	$21,913,175	(includes 60 KVA)		
100 KVA	$4,921	990	$4,871,379	(includes 112 KVA)		
167 KVA	$8,612	571	$4,917,658	(includes 150 KVA)		
250 KVA	$20,152	47	$947,138	(includes 200& 225 KVA)		
333 KVA	$17,230	553	$9,528,434	(includes 300 KVA)		
500 KVA	$17,732	441	$7,819,758	(includes 450 KVA)		
750 KVA	$24,003	83	$1,992,255			
1000 KVA	$29,625	125	$3,703,165	(includes 1250&1500 KVA)		
2000 KVA	$38,469	4	$153,876			
2500 KVA	$44,074	3	$132,221			
Total		37,657	$125,565,394			
Minimum System Cost			$86,305,815			
Actual System Cost			$125,565,394			
Customer-Related			69%			
Demand-Related			31%			
Cost per transformer calculations (2017)						
	Transformer	Other Material	Material Overhead	Install	Total Cost	Type
10 KVA	$875.63	$307.80	10%	$990.12	$2,291.8	Used cost of 15kVA tx

					9	
15 KVA	$875.63	$307.80	10%	$990.12	$2,291.89	1ph overhead
25 KVA	$1,008.67	$307.80	10%	$990.12	$2,438.24	1ph overhead
37 KVA	$1,455.00	$307.80	10%	$990.12	$2,929.20	1ph overhead
50 KVA	$1,600.50	$307.80	10%	$990.12	$3,089.25	1ph overhead
75 KVA	$2,400.98	$307.80	10%	$990.12	$3,969.78	1ph overhead
100 KVA	$3,265.35	$307.80	10%	$990.12	$4,920.59	1ph overhead
167 KVA	$6,600.00	$640.11	10%	$648.24	$8,612.36	1ph padmount 13kV/120/240
250 KVA	$14,200.00	$1,754.57	10%	$2,601.85	$20,151.88	3ph padmount 13kV/120/208
300 KVA	$11,544.15	$1,754.57	10%	$2,601.85	$17,230.44	3ph padmount 13kV/120/208
333 KVA	$12,000.00	$1,754.57	10%	$2,601.85	$17,731.88	3ph padmount 13kV/120/208
500 KVA	$13,239.20	$1,754.57	10%	$2,601.85	$19,095.00	3ph padmount 13kV/120/208
750 KVA	$17,701.09	$1,754.57	10%	$2,601.85	$24,003.08	3ph padmount 13kV/120/208
1000 KVA	$22,812.22	$1,754.57	10%	$2,601.85	$29,625.32	3ph padmount 13kV/347/600
2000 KVA	$30,852.00	$1,754.57	10%	$2,601.85	$38,469.08	3ph padmount 13kV/347/600
2500 KVA	$35,947.00	$1,754.57	10%	$2,601.85	$44,073.58	3ph padmount 13kV/347/600
Transformer Cost (2017)						
Data retrieved from March 2017 Workbook (transformer cost in table above also pulled from Workbook)						
		Install Cost	Other Material Cost			
Transformer (<= 100kVA)		$990.12	$307.80			
Transformer (167kVA 1ph)		$648.24	$640.11			
Transformer (>= 250kVA)		$2,601.85	$1,754.57			
Assumptions (2017)						
For each transformer size, the most common type (overhead/padmount), phasing, and voltage were used (based on study of ArcFM attributes)						
Since 10kVA transformers are smaller than the minimum system size, the cost of the 15kVA transformer install used for this size.						

Peak Load Carrying Capability Adjustment (PLCC)

While the minimum system is, in theory, designed to carry only a minimal amount of load, the actual facilities designated as the minimal size are actually capable of carrying some amount of demand, therefore overstating the level of the customer-related component. The actual amount of demand capability within the minimum system is a function of load density, minimum required clearances, minimum equipment standards, temperature, and other engineering considerations. Under traditional cost allocation techniques, each customer/connection attracts an equal allocation of the minimum system, plus each classification is allocated demand costs based on the total classification's non-coincident peaks. As such, it has been argued that a classification's non-coincident demand allocator is too large, because a portion of these peak demand-related costs are being covered through the per customer/connection minimum system allocation.

The correction of the problem of over allocating demand can be achieved by the application of a PLCC adjustment. The precise amount of a PLCC adjustment should match the definition of the minimum system adopted. In the FortisBC case, the engineers that provided the data associated with the minimum system method determined that the average PLCC for the FortisBC system is 1.09 kW per customer.

The PLCC adjustment determines how much demand for a rate classification can be met by the minimum system (number of customers/connections x PLCC for minimum system) and will credit this amount against the classification's non-coincident peak demands used for determining demand allocators. The adjusted classification's non-coincident peaks can then be used to allocate the distributor's demand-related costs, eliminating the double-counting. The number of customers/connections used for the PLCC should match the number of customers/connections used to allocate the customer component of the distributor's capital and O&M costs associated with poles, conductors and transformers.

FortisBC staff provided information for feeders under the current configuration and assuming a minimum sized system. The capacity of the system with the minimum size was then determined and compared to the number of customers served by the feeder. The resulting kVA per customer was calculated for each feeder and represents the PLCC for that feeder. The resulting average of 1.0 kW per customer was used as the PLCC for purposes of the COSA.

The following tables provide the details associated with the PLCC calculations.

FEEDER	VOLTAGE	Running Distance (km)	Conductor Length (km)	Conductor and Neutral Length (km)	Actual Customers per Feeder	Rural or Urban	Actual Peak kVA	Actual Connected kVA	20% of Peak kVA
W110S-CRA1	13	30.04	48.80	78.80	325	R	1755	3280	351
W110S-CRA2	13	54.74	121.80	174.72	516	R	2300	6548	460
W110S-CRA3	13	15.34	21.51	36.73	148	R	1696	1772	339.2
W110S-CRA4	13	29.86	49.58	76.16	314	R	1826	6949	365.2
W121S-CRE1	13	124.28	213.68	335.94	1145	R	7123	14409	1424.6
W121S-CRE2	13	60.76	92.55	151.76	1273	R	7500	16184	1500
W121S-CRE3	13	13.97	29.39	41.12	961	U	4175	11954	835
W121S-CRE4	13	81.60	159.71	239.87	854	R	6077	15711	1215.4
W124S-AAL1	13	90.29	185.24	274.72	705	R	3098	10705	619.6
W124S-AAL2	13	130.36	255.91	381.17	1073	R	8200	21890	1640
W124S-AAL3	13	24.20	44.46	66.00	2584	U	3139	11294	627.8
W129S-VAL1	13	82.28	117.47	199.28	786	R	3500	10812	700
W130S-PAS1	13	50.69	88.65	138.78	257	R	1528	4707	305.6
W130S-PAS2	13	43.52	68.47	111.74	396	R	2251	5642	450.2
W131S-PLA1	13	57.09	90.23	146.33	881	U	4149	11856	829.8
W131S-PLA2	13	93.44	141.53	234.15	1093	U	6308	14824	1261.6
W131S-PLA3	13	46.74	70.38	113.97	493	U	3959	7455	791.8
W201S-COT1	13	15.38	36.43	51.30	19	R	908	1863	181.6
W202S-SAL1	13	48.52	86.02	134.45	807	U	3344	10673	668.8
W202S-SAL2	13	40.92	69.01	107.89	448	R	4848	6125	969.6
W204S-HER1	13	26.69	53.87	80.45	192	R	1360	3158	272
W205S-FRU1	13	32.13	46.42	75.93	1052	U	4893	13145	978.6
W205S-FRU2	13	3.65	8.36	11.99	138	U	2930	1396	586
W206S-YMR1	13	35.15	52.21	87.20	278	R	1510	4264	302
W221S-CAS1	13	23.48	43.02	61.63	805	U	4600	15262	920
W221S-CAS2	13	41.96	88.35	100.24	1611	U	6370	16578	1274
W221S-CAS3	13	3.83	7.56	11.41	39	R	1036	390	207.2
W222S-BLU1	13	14.84	33.11	45.03	787	U	3262	10619	652.4
W222S-BLU2	13	41.19	82.33	111.86	1148	U	4150	16250	830
W246S-BEP1	13	12.48	26.60	44.39	287	U	3894	11826	778.8
W246S-BEP2	13	62.52	84.53	171.22	1079	R	4796	21052	959.2
W247S-GLM1	13	8.99	12.36	21.35	52	R	236	703	47.2
W247S-GLM2	13	28.24	58.66	79.22	2041	U	8898	22645	1779.6
W247S-GLM3	13	9.94	21.27	30.59	1022	U	4000	11855	800
W248S-STC1	13	28.52	55.26	81.41	1464	U	5652	14273	1130.4
W248S-STC2	13	30.93	64.90	95.15	930	U	3712	9916	742.4
W270S-CHR1	13	106.22	167.79	271.16	1411	U	4529	18430	905.8
W271S-RUC5	13	46.39	90.85	137.04	458	U	5740	8834	1148
W275S-GFT1	13	168.14	300.33	467.98	1632	R	9950	25620	1990
W289S-MDY1	13	1.64	4.92	6.56	1	R	3695	--	739
W289S-MDY2	13	30.37	48.19	78.47	422	R	1750	7557	350

FEEDER	VOLTAGE	Running Distance (km)	Conductor Length (km)	Conductor and Neutral Length (km)	Actual Customers per Feeder	Rural or Urban	Actual Peak kVA	Actual Connected kVA	20% of Peak kVA
W297S-GRS1	13	38.70	81.57	120.26	312	R	1014	3906	202.8
W297S-GRS2	13	55.45	100.87	155.98	420	R	1724	5676	344.8
W302S-GLE1	13	7.87	22.31	24.54	587	U	7228	17461	1445.6
W302S-GLE2	13	9.30	26.74	29.29	682	U	5491	17108	1098.2
W302S-GLE3	13	3.66	10.67	11.66	216	U	7759	13776	1551.8
W302S-GLE4	13	16.28	31.16	33.82	1350	U	6497	11304	1299.4
W302S-GLE5	13	6.26	69.00	106.64	1999	U	6992	18914	1398.4
W302S-GLE6	13	42.99	85.50	95.54	1300	U	5434	22320	1086.8
W302S-GLE7	13	25.52	51.38	54.86	2175	U	8188	20994	1637.6
W302S-GLE8	13	25.00	49.93	51.16	405	U	6965	25606	1393
W304S-HOL1	13	37.37	62.52	95.93	488	R	2975	9215	595
W304S-HOL2	13	16.21	39.05	44.81	1024	U	8523	21119	1704.6
W304S-HOL3	13	23.22	47.81	60.51	2250	U	9283	28122	1856.6
W304S-HOL4	13	18.62	38.79	50.51	1955	U	8575	23851	1715
W304S-HOL5	13	38.80	65.87	95.64	2394	U	8674	20943	1734.8
W304S-HOL7	13	18.10	33.21	46.85	1681	U	4828	12013	965.6
W305S-OKM1	13	11.31	18.38	21.93	1373	U	3467	10229	693.4
W305S-OKM2	13	13.18	29.87	35.89	1257	U	5211	15709	1042.2
W305S-OKM3	13	28.99	58.51	74.05	1430	U	8405	25756	1681
W305S-OKM4	13	4.07	11.87	13.68	739	U	3077	8008	615.4
W305S-OKM5	13	31.61	62.82	73.33	2404	U	9367	24760	1873.4
W308S-SEX1	13	17.60	44.34	54.51	605	U	5339	29271	1067.8
W308S-SEX2	13	59.26	105.99	129.80	2705	U	10106	29271	2021.2
W308S-SEX3	13	51.51	96.83	120.88	1356	U	6019	19354	1203.8
W308S-SEX4	13	29.33	83.11	95.85	599	U	10548	29349	2109.6
W316S-DUC1	13	14.01	31.63	40.74	427	U	3852	12130	770.4
W316S-DUC2	13	28.17	57.06	76.48	928	U	5258	20299	1051.6
W321S-KAL1	13	142.97	243.40	381.41	1165	R	6129	18201	1225.8
W330S-AWA1	13	24.56	40.36	60.27	378	R	2913	9167	582.6
W330S-AWA2	13	59.71	101.54	157.80	730	R	3888	14975	777.6
W323S-OKF1	13	35.11	68.92	99.76	924	U	3633	12134	726.6
W323S-OKF2	13	11.83	23.49	34.35	182	R	1780	6393	356
W323S-OKF3	13	44.58	92.81	124.47	995	R	4542	16120	908.4
W333S-PIN1	13	34.26	65.94	95.63	1173	U	6175	25221	1235
W333S-PIN2	13	81.44	168.33	245.82	672	R	5419	27426	1083.8
W333S-PIN3	13	40.04	71.24	108.87	1317	U	5739	19647	1147.8
W338S-OSO1	13	44.94	96.26	131.97	1709	U	7605	25440	1521
W338S-OSO3	13	87.10	180.36	257.38	1394	R	7051	32405	1410.2
W345S-KER1	13	78.57	167.32	243.98	1383	R	6308	21827	1261.6
W345S-KER2	13	141.89	326.25	463.31	1458	R	6384	28569	1276.8
W347S-HED2	13	52.23	125.36	177.59	423	R	1784	5463	356.8
W347S-HED3	13	34.88	77.40	110.96	219	R	595	2984	119

FEEDER	VOLTAGE	Running Distance (km)	Conductor Length (km)	Conductor and Neutral Length (km)	Actual Customers per Feeder	Rural or Urban	Actual Peak kVA	Actual Connected kVA	20% of Peak kVA
W371S-DGB1	13	56.14	97.06	114.27	1794	U	9531	25538	1906.2
W371S-DGB2	13	64.68	110.52	142.82	1456	U	8379	27327	1675.8
W371S-DGB3	13	38.18	43.01	58.80	581	R	3723	12319	744.6
W372S-LEE1	13	41.61	70.92	98.35	1958	U	8970	38493	1794
W386S-OLI1	13	76.87	130.56	200.31	967	R	4780	15794	956
W386S-OLI2	13	50.21	103.51	147.96	804	R	6500	24026	1300
W102S-KAS1	25	16.33	26.69	42.92	469	U	2500	6443	500
W102S-KAS2	25	73.41	60.93	97.64	514	R	3700	8189	740
W103S-COF1	25	40.94	88.03	128.46	355	R	1745	5666	349
W258S-CSC1	25	24.20	54.72	74.11	327	R	2533	10472	506.6
W258S-CSC2	25	19.31	35.63	53.91	1258	U	4364	11736	872.8
W258S-CSC3	25	50.86	88.99	137.05	771	U	2903	9536	580.6
W315S-JOR1	25	85.39	151.83	236.57	468	R	3518	8910	703.6
W347S-HED4	25	22.84	65.55	87.06	552	R	3598	9896	719.6
W320S-HUT2	8.66	32.04	76.39	103.07	404	U	3750	10575	750
W326S-WEB1	8.66	15.89	31.89	41.67	594	U	1920	15758	384
W326S-WEB2	8.66	33.45	67.86	98.56	594	U	3600	10027	720
W327S-SPL	8.66	8.01	7.37	14.67	36	R		834	0
W329S-TRC1	8.66	3.83	11.15	14.85	4	R	1512	546	302.4
W380S-RGA1	8.66	20.74	27.77	48.38	123	R	879	2888	175.8
BLK1	13	55.51	88.83	126.42	1401	U	5634	19248	1126.8
BLK2	13	55.54	108.54	141.74	1193	U	6553	9135.3	1310.6
BLK3	13	77.92	119.56	179.90	1562	U	7139	20756.1	1427.8
ELL1	13	18.16	53.68	59.10	357	U	9777	30306.5	1955.4
ELL2	13	86.83	140.23	211.38	1390	U	7216	27025.5	1443.2
ELL3	13	23.49	55.47	56.85	852	U	4860	18857	972
ELL4	13	38.41	76.61	101.35	372	U	3789	13840.1	757.8
BWS1	25	10.49	25.80	29.88	1014	U	6916	13549.6	1383.2
BWS2	25	13.50	35.47	38.78	1030	U	8219	25123.4	1643.8
BWS3	25	10.55	28.75	35.60	10	R	1703	3147	340.6
BEV1	13	49.60	88.97	119.73	2506	U	8705	27447.7	1741
BEV2	13	13.92	35.12	42.86	564	U	5888	9642.6	1177.6
BEV3	13	32.13	56.29	75.88	1264	U	5632	17695.9	1126.4
BEV4	13	19.59	40.53	53.01	1084	U	4348	13962.8	869.6
KRE1	13	3.00	9.00	10.54	4	U	2106	150	421.2
KRE2	13	20.55	40.39	43.61	861	U	4304	11333	860.8
KRE3	13	14.17	32.24	36.84	755	U	5549	12445	1109.8
KRE4	13	1.70	4.96	4.96	13	U	4205	1524	841
KRE5	13	4.03	12.05	12.89	251	U	6400	4253	1280
KRE6	13	16.91	35.82	42.06	2109	U	5494	21783	1098.8
KRE7	13	10.60	30.37	30.92	1361	U	9451	24247	1890.2
KRE8	13	5.56	16.63	16.63	405	U	5205	12401	1041
SAU1	13	5.71	8.68	11.66	572	U	1956	3011	391.2
SAU2	13	5.45	14.00	14.57	768	U	2024	5618	404.8

FEEDER	VOLTAGE	Running Distance (km)	Conductor Length (km)	Conductor and Neutral Length (km)	Actual Customers per Feeder	Rural or Urban	Actual Peak kVA	Actual Connected kVA	20% of Peak kVA
SAU3	13	12.54	29.00	30.29	1163	U	5648	10427	1129.6
SAU4	13	16.48	36.84	39.45	1256	U	4659	14339	931.8
SAU6	13	4.10	10.72	11.43	529	U	2243	4737	448.6
SAU7	13	6.84	19.63	19.66	496	U	2368	8386	473.6
SAU8	13	3.91	21.92	22.25	437	U	2884	8789	576.8
SAU9	13	1.90	5.69	6.23	1	U	3539	500.1	707.8
NKM1	13	9.48	22.76	25.92	526	U	3015	11763.3	603
NKM2	13	27.47	51.96	76.90	914	U	5077	18726.5	1015.4
NKM3	13	49.79	64.86	98.33	153	R	1395	10216	279
NKM4	13	9.14	26.33	34.27	517	U	3663	10390.3	732.6
OLI3	13	41.07	46.19	84.83	265	R	2014	5297.1	402.8
PRI1	13	2.22	6.67	8.83	5	R	6324	500	1264.8
PRI2	13	101.56	160.91	260.32	600	R	2919	8123	583.8
PRI4	13	249.88	528.63	772.50	1493	R	7693	24022.6	1538.6
PRI5	13	42.94	86.97	125.28	1665	U	5914	19531.1	1182.8
OOT1	13	80.18	126.48	188.91	1333	U	5488	15023	1097.6
OOT2	13	31.33	55.60	84.47	780	U	3600	10394	720
KET1	25	205.54	391.77	595.91	931	R	4550	21047	910
KET2	25	130.50	200.05	323.30	439	R	2667	10425.2	533.4
KET5	25	12.66	37.97	50.60	0	R	4200	11.1	840
KET6	25	46.75	115.91	162.61	106	R	4950	9476.1	990
								PLCC Peak Load	140336
								Actual Customers in Study	128446
								PLCC = (Peak kVA per customer)	1.09

Zero-Intercept Approach

An alternative to the minimum system approach used for classifying distribution costs is a zero-intercept approach. This is basically like the minimum system but takes the minimum sized system back to a theoretical minimum rather than the minimum size that is actually available for purchase. It calculates the cost of a pole, conductor or transformer as if it had zero capacity. That zero capacity system would theoretically reflect the customer-related component as it would be in place only to serve customers as it would have no ability to serve any amount of load.

The zero capacity system cost is calculated using a regression analysis that compares the cost of poles, conductor and transformers to their relative sizes. A regression generally yields a formula of cost = $a + b$ x size. The intercept is denoted by a and would reflect the cost if the size equals zero.

While the zero-intercept is theoretically valuable, in practice it is often not practical. The a component can result in a negative number, the relationship between cost and size may not be linear and often there are not sufficient data points to get a reliable result. The minimum system approach was used as it is the more common approach and is consistent with the 2009 COSA methodology.

The use of the PLCC with the minimum system approach reflects the same theory as the zero-intercept approach. The impact of the PLCC is to adjust for a large customer-related percentage resulting from a minimum system approach that incorporates equipment that is capable of carrying some amount of load. In both cases, the resulting allocation to classes with a large number of customers (like residential) is reduced. In the previous case of FortisBC, the results were similar when the zero-intercept approach was used rather than the minimum system method with the PLCC adjustment. Therefore, the minimum system with PLCC adjustment approach is maintained.

Appendix C – Load Analysis

To allocate costs within the COSA, a combination of customer, demand and energy factors are used. The customer and energy allocations are straightforward as both the number of customers and energy per class are easy to track and forecast. Demand per customer class is more difficult as there are several different types of demand that are considered. In the past, developing the necessary demand allocators requires piecing together information from various sources and estimating data in some cases. Since FortisBC installed AMI meters, hourly data is now available and was used to develop peak demands by class. The following defines the different types of loads necessary to develop all of the allocators by class. Actual monthly data for 2016 was used in all cases to develop the 2016 amounts. For 2017 a growth factor was applied for each rate class to reflect changes between 2016 actual amounts and the 2017 load forecast. The 2017 loads were used as the allocations factors in the COSA.

Energy

Energy per class is provided for each customer class based on metered kWh sales and is the starting point for the analysis. The annual energy forecast is broken out by month based on the 2016 actual shape. Losses for the total system are projected and are added to each class on the basis of the voltage level for the class. Projected losses are 2.86% for transmission voltage classes, 4.36% for primary voltage classes, and 10.11% for secondary voltage classes. The kWh at input includes losses and reflects the energy amounts needed to be generated or purchased.

Billing Demand and Individual Load Factors

For those customers with demand meters, the billing demand reflects the maximum demand during the month for each customer, summed together. For FortisBC, the Commercial (Rate 21), Large Commercial and Wholesale Customers are demand-metered and billed on the basis of kVA. These demands are converted from kVA to kW using the power factor by class. Because FortisBC had detailed metering data for its large customers, we had individual power factors for the wholesale and large commercial customers. The Wholesale power factor was set at 99%. The power factor for Rate 30 was 90% and the power factor for Rates 31 was 95%. The small commercial and commercial customers were assumed to have a power factor of 100%. The resulting sum of the individual peaks on a per kW basis is called the individual non-coincident peak (NCP).

For those customers that did not have billed demand, AMI data was used to develop the average individual load factor by month for each class. That load factor was then used to develop the NCP for those classes not billed on the basis of demand. This data is referred to as the Individual NCP and is not used for allocation purposes.

Group Coincident Factor and Class NCP

To get from the individual NCP to the NCP for the entire group a group coincident peak was used. This reflects the difference between the individual peak load summed together and the load at the time the class has its peak. The class NCP is not necessarily at the same time as the system peak. The group coincidence factors were developed on a monthly basis for each class using AMI data. The lighting class has a 100% group coincidence factor as all street lights are assumed to be on at the same time.

The NCP for the rate class is developed by multiplying the sum of the individual non-coincident peaks by the group coincident factor. The class NCP is used to allocate distribution assets as the distribution system is generally sized to serve localized peaks.

System Coincidence Factor and Coincident Peak

The final factor used in developing load data is the system coincidence factor. This factor reflects the percent of load that is on at the time of the system peak. For example, the system peak may be at 6 pm but the general service class peaks at 4 pm. The system coincidence factor represents the relationship between the highest peak for the class (NCP) and the contribution of that class to the system coincident peak (CP). Generation and power purchases are designed to serve the system load, as is the bulk transmission system. AMI data was used to develop the system coincidence factor by month for each rate class.

Multiplying the group NCP by the system coincident factor results in the CP for the rate class. This is an important measure for the COSA as it is used for the allocation of generation/power supply costs and for transmission costs. The total CP is a measured variable for the utility and it is also forecast on a monthly basis. The system forecast for the CP can be compared to the CP calculated by all of the steps leading from energy to CP. By reconciling these two different approaches to developing the same monthly peak forecast, the various assumptions made throughout the process can be adjusted to make sure that the two numbers balance against each other.

Load Data Sources for Peak Analysis

For completion of the FortisBC Cost of Service Study, FortisBC provided three primary sources of load data, a monthly billing summary file for each month of 2016 (“billing data”). Fifteen-minute Interval data for large industrial customers (“MV90 data”), and hourly interval data for a sample of meters from each rate class (“AMI data”). In addition, FortisBC was able to extract summary data from all AMI meters for specific coincidence questions and data validation.

FortisBC provided MV90 and AMI interval data in excel and text files for each customer class, except irrigation, initially. Industrial data was in two formats, excel output from the MV-90 system and XML output from Itron Meter Data Management System. In addition, excel files for a sample of load study meters was provided for residential and general service class in separate excel files. Each file included about 10 meters or so and included tabs with each month's data.

The billing data included 12 months of billing determinants for every customer with all the detail used to create bills. These files were split into twelve '.csv' text files, one for each month. These csv files were combined into one summary excel file for analysis. The summary files were used to analyze bill impacts and other. These files were the primary source of monthly summary billing data for the COSA. The MV90 data was provided as 'xml' files. The 'XML' data was arranged in contiguous interval files, the nested tables had to be expanded and the date/time fields aligned with the starting and ending interval for analysis. Most meters had a full year of 2016 data, but some meters only included March to December of 2016. The AMI data was provided in excel files for residential and general service classes with each file including a number of meters (usually around 10) with each month's hourly data in a separate tab.

For each sample by rate class, data was summarized hourly to generate kWh totals for the group, coincident peak for the group and non-coincident peak for the group. In addition, the non-coincident peak of each recorder was also totaled.

The number of meters varied by rate class. Table C-1 below shows the sample for each.

Table C-1
Summary of Load Study Meter by Rate Class

Rate Class	Load Study Count
Residential	
RS01	233
RS01A	51
RS02A	1
RS03	1
Residential Total	**286**
Small Commercial 20	48
Small Commercial 20M	22
Commercial Service 21	48
Commercial Service Total	**118**
Large Commercial Primary 30/32	36
Large Commercial Transmission 31	2
Lighting	NA
Irrigation	29
Wholesale Primary 40	4
Wholesale Transmission 41	1
Net Metering	129

Source files for residential were multiple spreadsheets, each spreadsheet containing 12 months of hourly data for a sample of meters. The files were split and ordered alphabetically before being provided to EES. All residential samples were combined for determining COSA load factors.

Processing for residential required that these source files be aggregated into a single file for summary analysis of peaks and average load factors. Each tab in each source file was imported into an Access database file with other files from the same rate class grouping. These became separate tables in a larger database file that could be used to store and export as needed. In addition, a summary file was created with multiple rate class grouping.

A partial example of the resulting summary analysis for each rate class grouping is shown below for RS01 files A through W for January through July of 2016.

RS01_A2W_Summary

System Peak Hour	1800	1800	1800	1800	1800	1800	1800
System Peak Day	3	4	1	21	17	6	28
System Peak Month	1	2	3	4	5	6	7
Group NCP	594	477	426	366	328	490	527
Group kWh	265,460	226,724	211,408	166,790	160,338	178,382	194,849
Group CP	594	440	415	293	289	472	494
Individual NCP Sum	1,370	1,291	1,270	1,175	1,112	1,224	1,238
Count	233	233	233	233	233	233	233
Non-Zero Usage	215	221	223	224	214	223	226
Average kW	2	1	1	1	1	1	1
Avg NCP	6	6	5	5	5	5	5
Avg LF	26.05%	25.24%	22.38%	19.72%	19.37%	20.24%	21.15%

These summary values were used to calculate load and coincidence factors for each rate class. However, final load factors were adjusted based on the overall system and group coincidence factors to resolve system loads. A graphical example for RS01 and other classes is shown in the following figures.

Figure C-1: RS01 Summary Chart

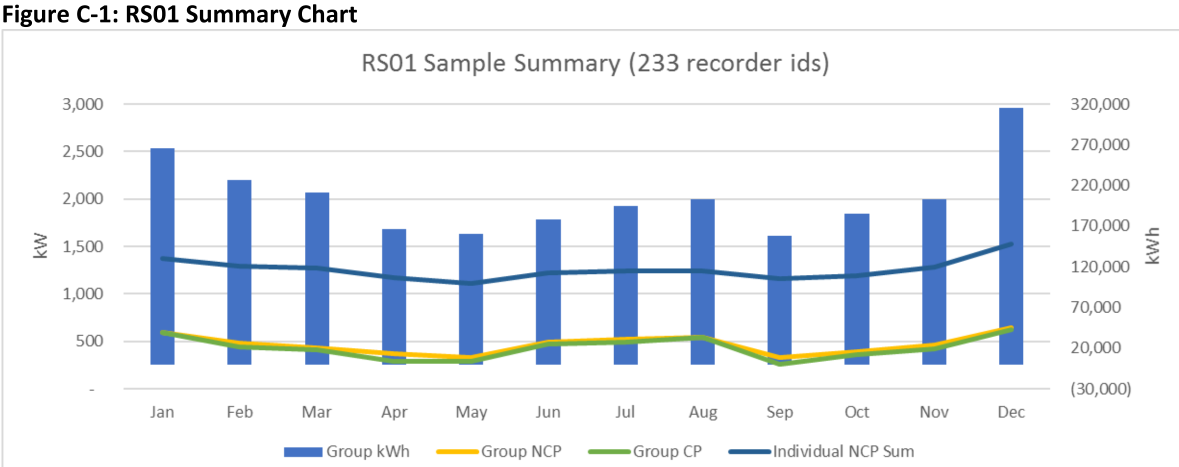


Figure C-2: IRR Summary Chart

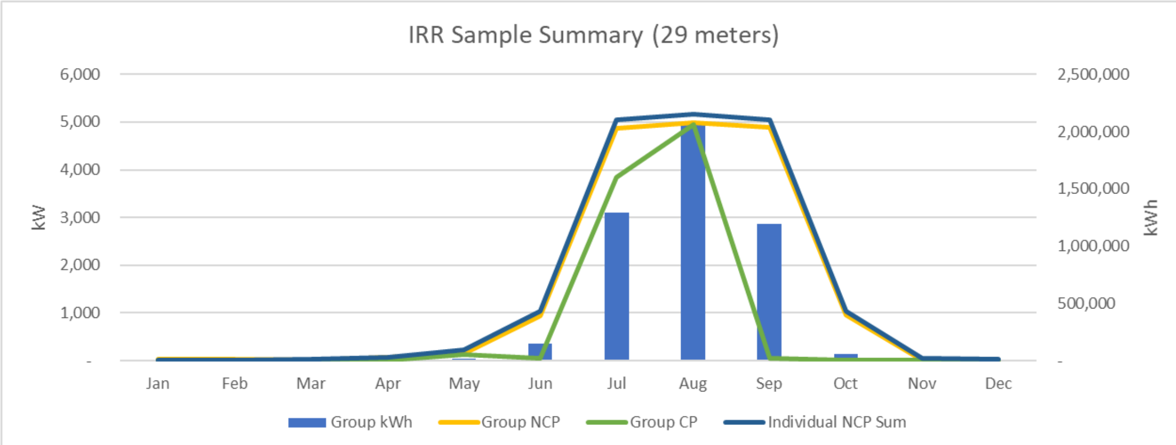


Figure C-3: Industrial 30 Summary Chart

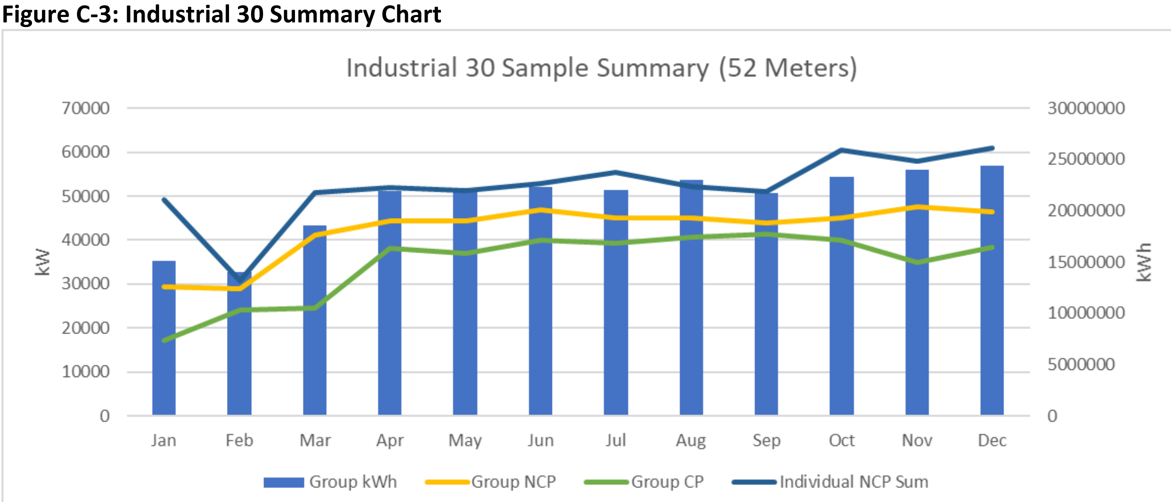


Figure C-4: GS20 Summary Chart

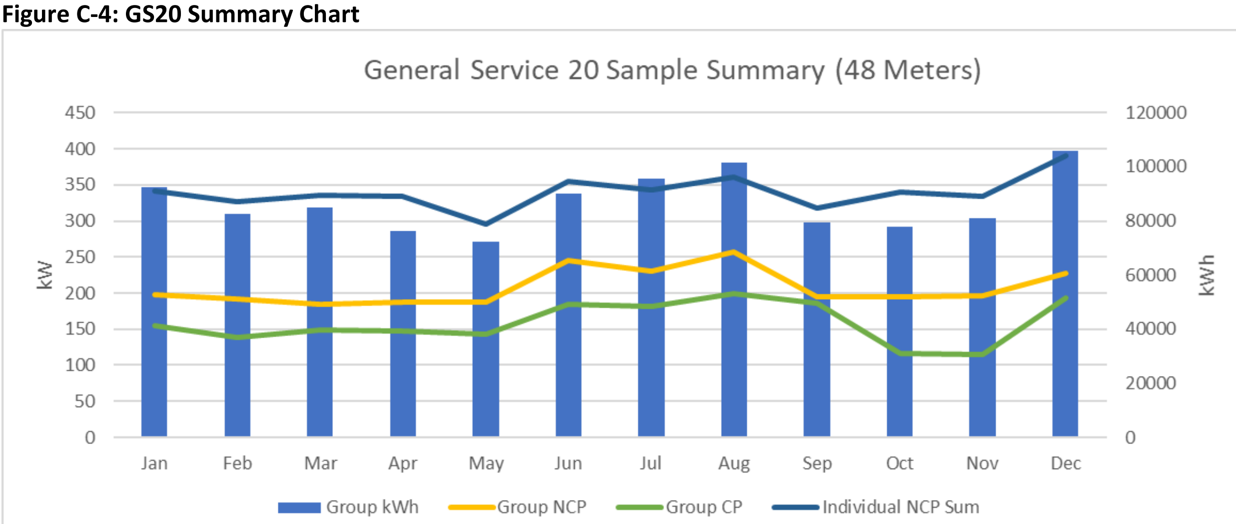
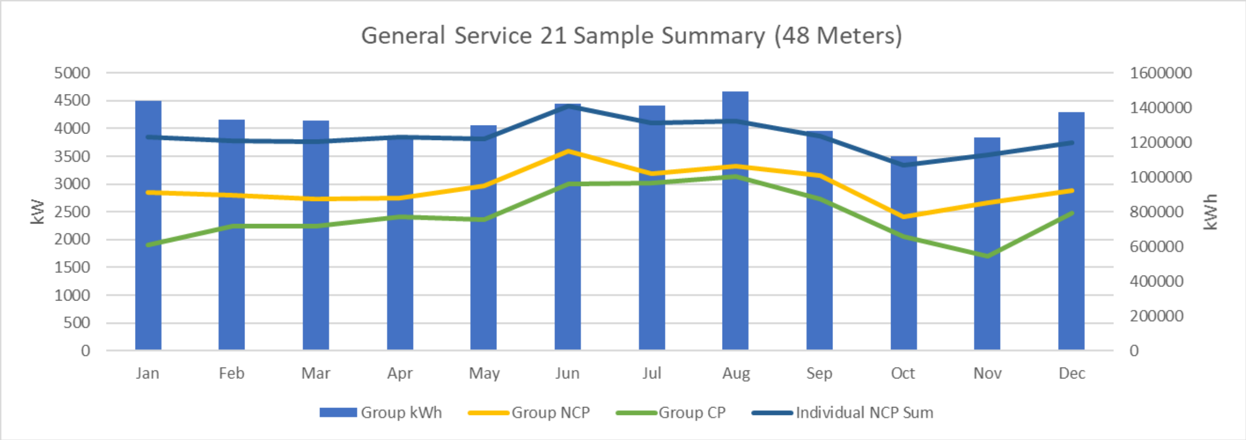


Figure C-5: GS21 Summary Chart



Appendix D – Review of Rates

Appendix D

Fortis BC 2017 COSA

CANADIAN JURISDICTIONAL REVIEW

Residential/Domestic Service

Canadian Utility	Energy Charge	Basic Charge	Minimum Bill	Demand Charge	Optional Rate	Special Rate
FortisBC	**Inclining Block (two-tier)** < 1600 kWh 10.117 c/kWh (60 day) > 1600 kWh 15.617 c/kWh (60 day)	**$/60 day billing** $32.09 ($16.27/month)		**No**	**Optional Time-of-Use rate**	**No**
SaskPower	**Flat** 13.740 c/kWh City 13.740 c/kWh Town 12.369 c/kWh Rural	**$/month** $22.01 City $22.01 Town, village and urban resort $31.77 Rural and rural resort	Basic Charge	**No**	**No**	**Diesel Generation Rate** 0.50733 $/kWh adder
Manitoba Hydro	**Flat** 8.196c/kWh	**$/month** $8.08 < 200 Amp $16.16 > 200 Amp	Basic Charge	**No**	**Seasonal Rate** Basic $96.96 / year 8.196 c / kWh	**No**
Hydro Quebec	**Inclining Block (two-tier)** < 30 kWh/day: 5.82 c/kWh Remaining energy: 8.92 c/kWh	**$/day** 40.64 c/day ($12.36/month)	Basic Charge	**> 50 kW demand** $6.21/kW/mo Winter $4.59/kW/mo Summer	**Dual Energy** Discount to alternative fuels when very cold (-12C or -15C)	**Dual Energy** Discount to alternative fuels when very cold (-12C or -15C)
Nova Scotia Power Flat	**Flat** 15.063 c/kWh	**$/month** 10.83	$/Month 18.82	**No**	**TOU** Restricted to defined electrical thermal storage with timing controls Basic $18.82/month 7.930 c / kWh 7am to 12 pm 19.421 c/kWh 12 pm to 4pm 15.063 c/kWh 4 pm to 11 pm 19.421 c/kWh 7am to 12 pm 8.136 c/kWh	**TOU** Restricted to defined electrical thermal storage with timing controls Basic $18.82/month 7.930 c / kWh 7am to 12 pm 19.421 c/kWh 12 pm to 4pm 15.063 c/kWh 4 pm to 11 pm 19.421 c/kWh 7am to 12 pm 8.136 c/kWh
Newfoundland Power	**Flat** 10.604 c/kWh	**$/month** $16.04 < 200 Amp $21.04 > 200 Amp	Basic Charge	**No**	**Seasonal Rate** Winter – premium (9.53 c/kwh) Non-winter – credit (1.297 c/kwh)	**Seasonal Rate** Winter – premium (0.0953 c/kwh) Non-winter – credit (1.297 c/kwh)
New Brunswick Power	**Flat** 10.81 c/kWh	**$/month** $21.60 Urban $23.69 Rural	Basic Charge	**No**	**No**	**No**
ATCO Electric Yukon	**Inclining Block (three-tier)(Non-gov.)** < 1000 kWh/mo. 12.14 c/kWh 1001-2500 kWh/mo. 12.82 c/kWh > 2500 kWh/mo. 13.99 c/kWh	**$/month** $14.65	Basic Charge	**No**	**No**	**Interim Rate Riders Approved in September of 2017** % basis varies by rate class
BC Hydro Energy Conservation Rate (default rate)	**Inclining Block (two-tier)** < 1350 kWh/mo. 8.58 c/kWh > 1350 kWh/mo. 12.87 c/kWh	**$/day** 18.99 c/day ($5.78/month)	Basic Charge	**No**	**No**	**Rate Rider** 5% rate rider applied to all charges
ATCO Electric Alberta	**Flat** 10.70 c/kWh	**$/day** 1.2686 c/day ($38.59/month)	Basic Charge	**No**	**Idle Service**	**Price adjustments, municipal assessment** Balancing pool adjustment Other adjustments
FortisAlberta	**Flat** 5.8351 c/kWh	**$/day** 0.7577 c/day ($23.05/month)	Service Charge	**No**	**No**	**Garage with sepearate meter billed on** SGS 41 schedule

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Fortis BC 2017 COSA

CANADIAN JURISDICTIONAL REVIEW

Residential/Domestic Service

Canadian Utility	Rates Effective Date	Rates Link to posted rates
FortisBC	1/1/2017	https://www.fortisbc.com/Electricity/CustomerService/ForHomes/YourElectricityRates/Pages/default.aspx
SaskPower	1/1/2017	http://www.saskpower.com/accounts-and-services/power-rates/
Manitoba Hydro	8/1/2017	https://www.hydro.mb.ca/regulatory_affairs/energy_rates/electricity/current_rates.shtml
Hydro Quebec	4/1/2017	http://www.hydroquebec.com/publications/en/docs/distribution-tariff/electricity-rates.pdf
Nova Scotia Power Flat	1/1/2017	http://www.nspower.ca/en/home/myaccount/billing-and-payments/power-rates.aspx
Newfoundland Power	7/1/2017	http://www.newfoundlandpower.com/aboutus/electricalrates/default.aspx http://www.newfoundlandpower.com/aboutus/pdf/Rate_Book_July2017.pdf
New Brunswick Power	4/1/2017	https://www.nbpower.com/media/727165/electricity_rates_card_april_2017.pdf https://www.nbpower.com/media/740318/rsp-manual_6-july-2017.pdf
ATCO Electric Yukon	9/1/2017	http://www.atcoelectricyukon.com/Documents/Regulatory/YECL%20YEC%20Rate%20Schedules%20Sept%202017.pdf http://www.atcoelectricyukon.com/Rates-and-Regulations/
BC Hydro Energy Conservation Rate (default rate)	4/1/2017	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/bchydro-electric-tariff.pdf https://www.bchydro.com/accounts-billing/rates-energy-use/electricity-rates.html
ATCO Electric Alberta	3/22/2017	http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/ATCOElectric-2017RateSchedules-April1-2017.pdf http://www.atcoelectric.com/Rates/tariffs/Current-Tariffs
FortisAlberta	3/21/2017	http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/Fortis-RateSchedule.pdf http://fortisalberta.com/customer-service/rates-and-billing/rates-options-and-riders http://fortisalberta.com/docs/default-source/default-document-library/2017-oct-rates-options-and-riders.pdf?sfvrsn=8

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Fortis BC 2017 COSA

CANADIAN JURISDICTIONAL REVIEW

Small General or Commercial Service (< 40 kW)

Canadian Utility	Energy Charge	Basic Charge	Minimum Bill	Demand Charge	Optional Rate
FortisBC GS20	**Flat** 10.195 c/kWh	**$/month** $38.80/2-months $19.40/mo.	**Basic Charge**	**No**	**No**
SaskPower >75 kVA	**Declining Block (two-tier)** Urban < 16,750 kWh/mo. 11.576 c/kWh >16,750 kWh/mo. 7.411 c/kWh Rural < 16,750 kWh/mo. 11.576 c/kWh >16,750 kWh/mo. 7.021 c/kWh	**$/month** $55.95 Urban $62.80 Rural	Basic monthly charge	**$/kVA** First 50 no charge Balance $15.065	**Time of Day metering** Greater of max kVA demand between 07:00 to 22:00 or 80% of max registered other hours
Manitoba Hydro < 200 kVA General Service Small	**Declining Block (three-tier)** < 11,000 kWh/mo. 8.609 c/kWh >11,000 <19,500 kWh/mo. 5.976 c/kWh >19,500 kWh/mo. 3.944 c/kWh	**$/month** $21.91	Basic monthly charge plus demand charge	**$/kVA** $10.10/kVA over 50 kVA only	
Hydro Quebec <65 kW Small Power	**Declining Block (two-tier)** < 15,090 kWh/mo. 9.78 c/kWh >15,090 kWh/mo. 6.88 c/kWh	**$/month** 36.99 (for 3-phase)	**$/Month** $12.33 plus demand charge	**$/kW** $17.43/kW Minimum billing demand 65% 12-month max contract rate	**credit for supply at medium or high voltage**
Nova Scotia Power Flat <45,000 kWh annual Small General	**Declining Block (two-tier)** < 200 kWh/kW/mo. 15.707 c/kWh > 200 kWh/kW/mo. 13.893 c/kWh	**$/Month** 12.65/month	Basic monthly charge	**No**	**No**
Newfoundland Power <100 kW	**Declining Block (two-tier)** < 3500 kWh/kW/mo. 10.511 c/kWh > 3500 kWh 7.746 c/kWh	**$/month** $21.2 (1-phase) $27.2 (3-phase)	Basic monthly charge Max Monthly Rate 18.728 c/kWh	**$/kW** **$9.16/kW (over 10 kW)** Dec, Jan, Feb, Mar $6.66 kVA other months	**No**
New Brunswick Power up to 750 kW Small Industrial	**Declining Block (two-tier)** < 100 kWh/kW/mo. 13.39 c/kWh > 100 kWh/kW/mo. 6.32 c/kWh	**None**	**Minimum contract demand**	**$/kW** $6.90/kW	**No**
ATCO Electric Yukon Gen Hydro Non-Gov	**Inclining Block (three-tier)(Non-gov.)** < 2000 kWh/mo. 10.00 c/kWh 1001-15,000 kWh/mo. 12.88 c/kWh 15,001-20,000 kWh/mo. 12.88 c/kWh > 20,000 kWh/mo. 12.86 c/kWh	**None**	**Demand charge but** not less than $36.95	**$/kW** $7.39/kW Greater of a) metered demand (b) 12-month max (c) The estimated demand. (d) 5 kilowatts.	**No**
BC Hydro <35 kW Small General Service	**Flat** 11.39 c/kWh	**$/day** 33.12 c/day $10.07/month	**Equal to Basic Charge**	**No**	**No**
ATCO Electric Alberta D21 <500 kW	**Declining Block (two-tier)** < 200 kWh 5.29 c/kWh >200 kWh 1.10 c/kWh	**$/day** 0.4940 c/day ($15.03/month)	Customer Charge	**$/kW/Day** 0.4021 $12.23/kW-Month	**Idle Service**
FortisAlberta 41 <75 KW	**Declining Block (two-tier)** < 200 kWh 1.6108 c/kWh >200 kWh 0.3872 c/kWh		Contract Demand Min. 3 kW	**$/kW/Day** 0.72923/kW Day <2 kW 0.48521/kW Day >2 14.75847083 22.18/kW-mo. 14.76/kW-mo.	**No**

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CANADIAN JURISDICTIONAL REVIEW

Small General or Commercial Service (< 40 kW)

Canadian Utility	Special Rate	Rates Effective Date	Rates Link to posted rates
FortisBC GS20	**No**	**1/1/2017**	**https://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/Documents/FortisBCElectricTariff.pdf**
SaskPower >75 kVA	**Customer owned transformation rates**	**1/1/2017**	http://www.saskpower.com/accounts-and-services/power-rates/
Manitoba Hydro < 200 kVA General Service Small		**8/1/2017**	https://www.hydro.mb.ca/regulatory_affairs/energy_rates/electricity/current_rates.shtml
Hydro Quebec <65 kW Small Power	**credit for supply at medium or high voltage**	**4/1/2017**	**http://www.hydroquebec.com/publications/en/docs/distribution-tariff/electricity-rates.pdf**
Nova Scotia Power Flat <45,000 kWh annual Small General	**Fuel adjustment mechanism**	**1/1/2017**	**http://www.nspower.ca/en/home/myaccount/billing-and-payments/power-rates.aspx**
Newfoundland Power <100 kW	**$/Month Max Charge** Max 18.728 c/kwh	**7/1/2017**	**http://www.newfoundlandpower.com/aboutus/electricalrates/default.aspx** http://www.newfoundlandpower.com/aboutus/pdf/Rate_Book_July2017.pdf
New Brunswick Power up to 750 kW Small Industrial	**Declining Discount Firm Rate** New fac. after April 1, 2000 or facilities that were substantially shut down as at October 1, 2000 declining discount on Demand Addl firm load.	**4/1/2017**	**https://www.nbpower.com/media/727165/electricity_rates_card_april_2017.pdf**
ATCO Electric Yukon Gen Hydro Non-Gov	**Interim Rate Riders Approved in September of 2017** % basis varies by rate class	**9/1/2017**	**http://www.atcoelectricyukon.com/Documents/Regulatory/YECL%20YEC%20Rate%20Schedules%20Sept%202017.pdf** http://www.atcoelectricyukon.com/Rates-and-Regulations/
BC Hydro <35 kW Small General Service	**1.5% primary metering discount** $0.25/kW credit for customer supplied transformation 5% Rate Rider	**4/1/2017**	**https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/bchydro-electric-tariff.pdf** https://www.bchydro.com/accounts-billing/rates-energy-use/electricity-rates.html
ATCO Electric Alberta D21 <500 kW	**Price adjustments, municipal assessment** Balancing pool adjustment Other adjustments	**3/22/2017**	**http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/ATCOElectric-2017RateSchedules-April1-2017.pdf** http://www.atcoelectric.com/Rates/tariffs/Current-Tariffs
FortisAlberta 41 <75 KW	**Agreement and power factor correction**	**3/21/2017**	**http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/Fortis-RateSchedule.pdf** http://fortisalberta.com/customer-service/rates-and-billing/rates-options-and-riders http://fortisalberta.com/docs/default-source/default-document-library/2017-oct-rates-options-and-riders.pdf?sfvrsn=8

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CANADIAN JURISDICTIONAL REVIEW

Commercial/General Service (>40 kW <500 kW)

Canadian Utility	Energy Charge	Basic Charge	Minimum Bill	Demand Charge	Optional Rate
FortisBC GS21	**Declining Block (two-tier)** < 8000 kWh 8.663 c/kWh (60 day) > 8000 kWh 7.191 c/kWh (60 day)	**$/month** $16.48		**> 40 kW demand** $8.60/kW/mo	**No**
SaskPower >75 kVA	**Declining Block (two-tier)** Urban < 16,750 kWh/mo. 11.576 c/kWh >16,750 kWh/mo. 7.411 c/kWh Rural < 16,750 kWh/mo. 11.576 c/kWh >16,750 kWh/mo. 7.021 c/kWh	**$/month** $55.95 Urban $62.80 Rural	Basic monthly charge	**$/kVA** First 50 no charge Balance $15.065	**Time of Day metering** Greater of max kVA demand between 07:00 to 22:00 or 80% of max registered other hours
Manitoba Hydro >200 kVA General Service Medium	**Declining Block (three-tier)** <11,000 kWh/mo. 8.609¢/kWh >11,000 kWh/Mo. and <19,500 kWh/Mo. 5.976¢/kWh > 19,500 kWh/mo. 3.944¢/kWh	**$/month** $32.61	Basic monthly charge plus demand charge	**$/kVA** $10.10/kVA over 50 kVA only Greater of measured demand 25% of contract 25% 12-month max	**Surplus energy program** Spot market energy plus distribution
Hydro Quebec >50 kW	**Declining Block (two-tier)** < 210,000 kWh/mo. 4.97 c/kWh >210,000 kWh/mo. 3.69 c/kWh	**None, minimum bill only**	**$/Month** $36.99, three phase plus demand charge	**$/kW** $14.43/kW Minimum billing demand 65% 12-month max contract rate	**credit for supply at medium or high voltage**
Nova Scotia Power Flat >32,000 kWh annual	**Declining Block (two-tier)** < 200 kWh/kW/mo. 11.784 c/kWh > 200 kWh/kW/mo. 8.505 c/kWh	**None**	**$/Month** 12.65/month	**$/kW** $10.497/kW	**No**
Newfoundland Power >110 kVa or 100 kW	**Declining Block (two-tier)** < 150 kWh/kW/mo. Up to 50,000 kWh 8.894 c/kWh > 50,000 kWh 7.055 c/kWh	**$/month** $49.57	Basic monthly charge	**$/kVA** **$7.74/kVA** Dec, Jan, Feb, Mar $5.24 kVA other months	**No**
New Brunswick Power up to 750 kW	**Declining Block (two-tier)** < 100 kWh/kW/mo. 13.39 c/kWh > 100 kWh/kW/mo. 6.32 c/kWh	**None**	**Minimum contract demand**	**$/kW** $6.90/kW	**No**
ATCO Electric Yukon Gen Hydro Non-Gov	**Inclining Block (three-tier)(Non-gov.)** < 2000 kWh/mo. 10.00 c/kWh 1001-15,000 kWh/mo. 12.88 c/kWh 15,001-20,000 kWh/mo. 12.88 c/kWh > 20,000 kWh/mo. 12.86 c/kWh	**None**	**Demand charge but** not less than $36.95	**$/kW** $7.39/kW Greater of a) metered demand (b) 12-month max (c) The estimated demand. (d) 5 kilowatts.	**No**
BC Hydro >35 kW Medium General Service	**Flat** 8.80 c/kWh	**$/day** 24.29 c/day $7.39/month	**50% 12-month demand charge**	**$/kW** $4.92/kw	**No**
ATCO Electric Alberta D21 <500 kW	**Declining Block (two-tier)** < 200 kWh 5.29 c/kWh >200 kWh/mo. 1.10 c/kWh	**$/day** 0.4940 c/day ($15.03/month)	Customer Charge	**$/kW/Day** 0.4021 $12.23/kW-Month	**Idle Service**
FortisAlberta 61 <2000 kW	**Flat** 0.3964 c/kWh	**$/day** 0.7577 c/day ($23.05/month)	Service Charge	**$/kW/Day** 0.35834/kW Day <50 kW 0.22739/kW Day >50 <450 kW 0.20226 kW-Day >450 kW 10.90/kW-mo. 6.92/kW-mo. 6.15/kW-mo.	**No**

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Commercial/General Service (>40 kW <500 kW)

Canadian Utility	Special Rate	Rates Effective Date	Rates Link to posted rates
FortisBC GS21	**No**	**1/1/2017**	**https://www.fortisbc.com/Electricity/CustomerService/ForHomes/YourElectricityRates/Pages/default.aspx** **https://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/Documents/FortisBCElectricTariff.pdf**
SaskPower >75 kVA	**Customer owned transformation rates**	**1/1/2017**	http://www.saskpower.com/accounts-and-services/power-rates/
Manitoba Hydro >200 kVA General Service Medium	**Customer owned transformation rates** Primary metering of multiple utility-owned transformation – add 2% to kVA for each transformation greater than one.	**8/1/2017**	https://www.hydro.mb.ca/regulatory_affairs/energy_rates/electricity/current_rates.shtml
Hydro Quebec >50 kW	**credit for supply at medium or high voltage**	**4/1/2017**	**http://www.hydroquebec.com/publications/en/docs/distribution-tariff/electricity-rates.pdf**
Nova Scotia Power Flat >32,000 kWh annual	**Fuel adjustment mechanism**	**1/1/2017**	**http://www.nspower.ca/en/home/myaccount/billing-and-payments/power-rates.aspx**
Newfoundland Power >110 kVa or 100 kW	**$/Month Max Charge** Max 18.728 c/kwh	**7/1/2017**	**http://www.newfoundlandpower.com/aboutus/electricalrates/default.aspx** http://www.newfoundlandpower.com/aboutus/pdf/Rate_Book_July2017.pdf
New Brunswick Power up to 750 kW	**Declining Discount Firm Rate** New fac. after April 1, 2000 or facilities that were substantially shut down as at October 1, 2000 declining discount on Demand Addl firm load.	**4/1/2017**	**https://www.nbpower.com/media/727165/electricity_rates_card_april_2017.pdf**
ATCO Electric Yukon Gen Hydro Non-Gov	**Interim Rate Riders Approved in September of 2017** % basis varies by rate class	**9/1/2017**	**http://www.atcoelectricyukon.com/Documents/Regulatory/YECL%20YEC%20Rate%20Schedules%20Sept%202017.pdf** http://www.atcoelectricyukon.com/Rates-and-Regulations/
BC Hydro >35 kW Medium General Service	**1.5% primary metering discount** $0.25/kW credit for customer supplied transformation 5% Rate Rider	**4/1/2017**	**https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/bchydro-electric-tariff.pdf** https://www.bchydro.com/accounts-billing/rates-energy-use/electricity-rates.html
ATCO Electric Alberta D21 <500 kW	**Price adjustments, municipal assessment** Balancing pool adjustment Other adjustments	**3/22/2017**	**http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/ATCOElectric-2017RateSchedules-April1-2017.pdf** http://www.atcoelectric.com/Rates/tariffs/Current-Tariffs
FortisAlberta 61 <2000 kW	**Agreement and power factor correction**	**3/21/2017**	**http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/Fortis-RateSchedule.pdf** http://fortisalberta.com/customer-service/rates-and-billing/rates-options-and-riders http://fortisalberta.com/docs/default-source/default-document-library/2017-oct-rates-options-and-riders.pdf?sfvrsn=8

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Industrial Service (500 kVA+/Primary)

Canadian Utility	Energy Charge	Basic Charge	Minimum Bill	Demand Charge	Optional Rate
FortisBC ID30	**Flat** 5.571 c/kWh	**$/month** $945.04	**Customer Charge $945.04 +** 25% Contract Demand or 75% max kVA prev 11 months	**$/kVA** $9.19 Greater of 25% of Contract Demand max kVA current month 75% of max kVA prev 11 months	**TOU Option** On-Peak Hours: 7:00 am - 12:00 pm / 4:00 pm - 10:00 pm business days Off-Peak 10:00pm-7:00am, 12:00pm-4:00pm business days weekends and statutory holidays
SaskPower	**Flat** 7.004 c/kWh Urban 7.004 c/kWh Rural	**$/month** $234.04 Urban $288.88 Rural	**None**	**$/kVA** $13.475/kVA	**Power Time of Use Rate**
Manitoba Hydro >100 kVA Large Gen Serv	**Flat** 3.342 c/kWh		**None**	**$/kVA** $6.53/kVA Greater of measured demand 25% of contract 25% 12-month max	**Surplus energy program** Spot market energy plus distribution
Hydro Quebec >65 kVA	**Flat** 9.97 c/kWh		**$/month** $31.55	**$/kW** $4.20/kW	**Short-term contracts for lower use periods**
Nova Scotia Power Flat >249 kVA medium ind	**Flat** 7.682 c/kWh		**$/month** $12.65	**$/kW** $12.501/kW	**No**
Newfoundland Power >1000 kVA	**Declining Block (two-tier)** < 75,000 kWh/mo. 8.564 c/kWh > 75,000 kWh/mo. 6.986 c/kWh	**$/month** $86.39	**None**	**$/kVA** **$7.46/kVA** Dec, Jan, Feb, Mar $4.96 kVA other months	**No**
New Brunswick Power <750 kW contract dem	**Flat** 5.20 c/kWh	**None/Contract Demand**	**None**	**$/kW** 14.07/kW Greater of measured demand 90% of max kVA 90% of firm non-curtailable 90% of max 12-month 90% lesser avg prev year excluding april-nov	**No**
ATCO Electric Yukon >1000 kW	**Flat** 7.81 c/kWh		**None**	**$/kVA** 15.42/kVA	**Winter contract load** no less than 2/3 max demand
BC Hydro >150 kW or >550,000 kWh	**Flat** 5.50 c/kWh	**$/day** 24.29 c/day $7.39/month	**50% 12-month demand charge**	**$/kW** $11.21/kW	**No**
ATCO Electric Alberta D21 <500 kW	**Declining Block (two-tier)** < 200 kWh 5.29 c/kWh >200 kWh/mo. 1.10 c/kWh	**$/day** 0.4940 c/day ($15.03/month)	Customer Charge	**$/kW/Day** 0.4021 $12.23/kW-Month	**Idle Service**
FortisAlberta 61 <2000 kW	**Flat** 0.3964 c/kWh	**$/day** 0.7577 c/day ($23.05/month)	Service Charge	**$/kW/Day** 0.35834/kW Day <50 kW 0.22739/kW Day >50 <450 kW 0.20226 kW-Day >450 kW 10.90/kW-mo. 6.92/kW-mo. 6.15/kW-mo.	**No**

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Industrial Service (500 kVA+/Primary)

Canadian Utility	Special Rate	Rates Effective Date	Rates Link to posted rates
FortisBC ID30	**Discount for transmission voltage** $2.676 kVA for customer-owned transformation	1/1/2017	https://www.fortisbc.com/Electricity/CustomerService/ForHomes/YourElectricityRates/Pages/default.aspx https://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/Documents/FortisBCElectricTariff.pdf
SaskPower	**Minimum Bill** Basic Monthly Charge plu $4.702/kVA E10 (72 kV) and E12 (138 kV) - service closed to new customers	1/1/2017	http://www.saskpower.com/accounts-and-services/power-rates/
Manitoba Hydro >100 kVA Large Gen Serv	**Customer owned transformation rates** Primary metering of multiple utility-owned transformation – add 2% to kVA for each transformation greater than one.	8/1/2017	https://www.hydro.mb.ca/regulatory_affairs/energy_rates/electricity/current_rates.shtml
Hydro Quebec >65 kVA	**$10.23/kW power factor penalty for max power over real power**	4/1/2017	http://www.hydroquebec.com/publications/en/docs/distribution-tariff/electricity-rates.pdf
Nova Scotia Power Flat >249 kVA medium ind	**subject to fuel adjustment mechanism**	1/1/2017	http://www.nspower.ca/en/home/myaccount/billing-and-payments/power-rates.aspx
Newfoundland Power >1000 kVA	**$/Month Max Charge** Max 18.728 c/kwh .	7/1/2017	http://www.newfoundlandpower.com/aboutus/electricalrates/default.aspx http://www.newfoundlandpower.com/aboutus/pdf/Rate_Book_July2017.pdf
New Brunswick Power <750 kW contract dem	**No**	4/1/2017	https://www.nbpower.com/media/727165/electricity_rates_card_april_2017.pdf
ATCO Electric Yukon >1000 kW	**Peak Shaving Credit** 50% of the demand Charge times the Peak Shaved Load Base Load Energy amount fuel price riders for certain customers Interim Rate Rider Approved September 1, 2017	9/1/2017	http://www.atcoelectricyukon.com/Documents/Regulatory/YECL%20YEC%20Rate%20Schedules%20Sept%202017.pdf http://www.atcoelectricyukon.com/Rates-and-Regulations/
BC Hydro >150 kW or >550,000 kWh	**1.5% primary metering discount** $0.25/kW credit for customer supplied transformation 5% Rate Rider	4/1/2017	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/bchydro-electric-tariff.pdf https://www.bchydro.com/accounts-billing/rates-energy-use/electricity-rates.html
ATCO Electric Alberta D21 <500 kW	**Price adjustments, municipal assessment** Balancing pool adjustment Other adjustments	3/22/2017	http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/ATCOElectric-2017RateSchedules-April1-2017.pdf http://www.atcoelectric.com/Rates/tariffs/Current-Tariffs
FortisAlberta 61 <2000 kW	**Agreement and power factor correction**	3/21/2017	http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/Fortis-RateSchedule.pdf http://fortisalberta.com/customer-service/rates-and-billing/rates-options-and-riders http://fortisalberta.com/docs/default-source/default-document-library/2017-oct-rates-options-and-riders.pdf?sfvrsn=8

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Irrigation or Agriculture Service

Canadian Utility	Energy Charge	Basic Charge	Minimum Bill	Demand Charge	Optional Rate
FortisBC IR60 IR61 (TOU)	**Flat** 7.259 c/kWh On-peak 18.510 c/kWh (S) 19.235 c/kWh (NS) 5.297 c/kWh (Shoulder); Off-peak 3.999 c/kWh (S) 4.823 c/kWh (NS) 3.323 c/kWh (Shoulder);	**$/month** $20.96/month $51.59/month			
BC Hydro RS 1401	**Seasonal Inclining Block** 5.56 c/kWh (S) < 150 kWh/mo. 5.56 c/kWh >150 kWh/mo. 44.09 c/kWh	**$/day**	**$5.56/kW Minimum Charge (S)** 44.47/kW >500 kWh (NS)	**$/kW**	25 c/kWh discount for customer-owned transformer
SaskPower	**Declining Block (two-tier)** < 16,000 kWh/mo. 12.224 c/kWh >16,000 kWh/mo. 5.300 c/kWh	**$/month** $33.77/month	Basic monthly charge + $4.702/KVA / > 50 kVA	**$/kVA** $12.408/KVA / > 50 kVA	
Manitoba Hydro NA	**Flat**	**$/month**	Basic monthly charge	**$/kVA**	
Hydro Quebec NA				**$/kW**	
Nova Scotia Power NA	**Flat**			**$/kW**	
Newfoundland Power NA				**$/kVA**	
New Brunswick Power NA				**$/kW**	
ATCO Electric Yukon NA				**$/kW**	
BC Hydro 1401	**Flat / Seasonal Tier** 5.56 c/kWh during March-October First 150 kWh in off-season 5.56 c/kWh Over 150 kWh in off-season penalty rate of 44.09 c/kWh	**Minimum Charge**	**$5.56/kW of connected load**	**No**	**No**
ATCO Electric Alberta D25	**Flat** 1.11 c/kWh	**$/day** 73.57 c/day ($22.38/month)	Customer Charge	**$/kW/Day** 58.16 c/kW/Day $17.69/kW-Month	**Idle Service**
FortisAlberta 26	**Flat** 8.2493 c/kWh	kW Capacity Demand	kW Capacity Demand	**Billed Annual kW Capacity** 0.1893 $/kW-day ($5.75/month) Idle Charges 0.1627 $/kW-day ($4.95/month)	**No**

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CANADIAN JURISDICTIONAL REVIEW

Irrigation or Agriculture Service

Canadian Utility	Special Rate	Rates Effective Date	Rates Link to posted rates
FortisBC IR60 IR61 (TOU)	**No**	**1/1/2017**	**https://www.fortisbc.com/Electricity/CustomerService/ForHomes/YourElectricityRates/Pages/default.aspx** **https://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/Documents/FortisBCElectricTariff.pdf**
BC Hydro RS 1401		**4/1/2017**	**https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/bchydro-electric-tariff.pdf**
SaskPower	**Customer owned transformation rates**	**1/1/2017**	http://www.saskpower.com/wp-content/uploads/Service_Rates_Farm_2017.pdf
Manitoba Hydro NA	**Customer owned transformation rates**	**8/1/2017**	https://www.hydro.mb.ca/regulatory_affairs/energy_rates/electricity/current_rates.shtml
Hydro Quebec NA		**4/1/2017**	**http://www.hydroquebec.com/publications/en/docs/distribution-tariff/electricity-rates.pdf**
Nova Scotia Power NA		**1/1/2017**	**http://www.nspower.ca/en/home/myaccount/billing-and-payments/power-rates.aspx**
Newfoundland Power NA		**1/1/2016**	**http://www.newfoundlandpower.com/aboutus/pdf/RateBookJuly2016.pdf**
New Brunswick Power NA		**4/1/2017**	**https://www.nbpower.com/media/727165/electricity_rates_card_april_2017.pdf**
ATCO Electric Yukon NA		**1/1/2011**	**http://www.atcoelectricyukon.com/Documents/Regulatory/YECL_YEC_Rate_Schedules_Jul_01_2011_FINAL.pdf**
BC Hydro 1401	**5% Rate Rider applied to all charges before taxes and levie**	**4/1/2017**	**https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/bchydro-electric-tariff.pdf** https://www.bchydro.com/accounts-billing/rates-energy-use/electricity-rates.html
ATCO Electric Alberta D25	**Price adjustments, municipal assessment** Balancing pool adjustment Other adjustments	**3/22/2017**	**http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/ATCOElectric-2017RateSchedules-April1-2017.pdf** http://www.atcoelectric.com/Rates/tariffs/Current-Tariffs
FortisAlberta 26	**Agreement and power factor correction**	**3/21/2017**	**http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/Fortis-RateSchedule.pdf** http://fortisalberta.com/customer-service/rates-and-billing/rates-options-and-riders http://fortisalberta.com/docs/default-source/default-document-library/2017-oct-rates-options-and-riders.pdf?sfvrsn=8

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Net Metering

Canadian Utility	Energy Charge	Basic Charge	Maximum Capacity kW	Minimum Bill	Demand Charge	Application Fee	Banking/Roll-Over Policy
FortisBC	retail rate for residential and commercial must be renewable	Same as Retail	50 kW	Same as Retail	Same as Retail	None	In the event that the operation of a renewable energy generating system results in a credit balance on the Customer-Generator's account at the end of a calendar year, the credit will be purchased by the Company. If such amounts are not large, they will be carried forward and included in the billing calculation for the next period at the discretion of the Company.
SaskPower	retail rate for residential and commercial must be renewable	Same as Retail	100 kW	Same as Retail	Same as Retail	$ 315.00 $475 bi-directional meter fee, 20% rebate on capital installation costs up to $20,000	Any excess electricity is carried over to the following month and applied against that month's consumption. A credit appears on your monthly bill showing the net amount of electricity that has been banked. Your excess power should be used within the year; if not, at the end of 12 months on your net metering anniversary date, any credits you may have for excess electricity sent to the grid will reset to zero.
Manitoba Hydro	standard residential run-off rate varies by type of generation	Same as Retail	200 kW	Same as Retail	Same as Retail	bi-directional meter fee interconnection costs Solar program $1/W load subsidy	
Hydro Quebec	residential rate less applicable credit for supply cannot be negative	Same as Retail	50 kW	Same as Retail	Same as Retail	N/A	surplus bank is reset to 0 at the start of the consumption period beginning on or after March 31 following application of the conditions set out in Article 2.53 and every 24 months thereafter
Nova Scotia Power Flat	retail rate for residential and commercial must be renewable	Same as Retail	100 kW	Same as Retail	Same as Retail	N/A	"Banked" excess self-generation will create an energy credit to be held by the customer-generator and will carry over until the customer's annual anniversary date at which time the energy credit will be set to zero with compensation to the customer-generator priced at the appropriate retail rate. Customers are able to use their generator to supply electricity to multiple metered accounts - such as a home and a business with the same account owner - within a geographical area known as a distribution zone. For example, while a larger wind turbine may not be feasible to use at a single home, it could potentially be used to help power multiple properties with the same account owner in a given community.
Newfoundland Power	Retail rate	Same as Retail	100 kW	Same as Retail No max rate test		N/A	The balance of the Customer's Banked Energy Credits carried forward will be settled annually by means of a credit on the Customer's bill for the Annual Review Billing Month. The Annual Review Billing Month will be determined by the Customer, in consultation with the Company, during the process of implementing Net Metering Service. Settlement of Banked Energy Credits will be computed based upon the then-current 2nd block energy charge
New Brunswick Power	Same as Retail	Same as Retail	100 kW	Same as Retail	Same as Retail	N/A	Any excess electricity not used during the current billing period will appear as a credit and will be carried forward to subsequent months up to March of each year. After March, all credits are reduced to zero.
ATCO Electric Yukon	N/A	N/A	N/A	N/A	N/A	N/A	N/A
BC Hydro	retail rate for residential and commercial must be renewable credit balance at $9.99 c/kWh	Same as Retail	100 kW	Same as Retail	Same as Retail	Actual Cost up to $600	For all electricity represented by the Generation Credit Balance remaining in the Customer's Generation Account at any Anniversary Date, BC Hydro will pay 9.99 cents per kWh.
ATCO Electric Alberta	Micro-Generators can choose retail rate or wholesl must be renewable Must become a pool participant in AESO to sell wholesale	Same as Retail	150 kW	Same as Retail	Same as Retail	N/A	the service provider must, at least once in each calendar year, settle with each micro-generator the unused credits accumulated by that micro-generator in the form of a payment, an offset against any charges owed by the micro-generator or a combination of payment and offset
FortisAlberta	Micro-Generators can choose retail rate or wholesl must be renewable Must become a pool participant in AESO to sell wholesale	Same as Retail	150 kW	Same as Retail	Same as Retail	N/A	the service provider must, at least once in each calendar year, settle with each micro-generator the unused credits accumulated by that micro-generator in the form of a payment, an offset against any charges owed by the micro-generator or a combination of payment and offset

Appendix D

Fortis BC 2017 COSA

CANADIAN JURISDICTIONAL REVIEW

Net Metering

Canadian Utility	Rates Effective Date	Rates Link to posted rates
FortisBC	1/1/2017	https://fortisbc.com/Electricity/CustomerService/NetMeteringProgram/Pages/default.aspx
SaskPower	1/1/2017	http://www.saskpower.com/efficiency-programs-and-tips/generate-your-own-power/self-generation-programs/net-metering-program/
Manitoba Hydro	8/1/2017	https://www.hydro.mb.ca/environment/customer_owned_generation/index.shtml https://www.hydro.mb.ca/environment/solar.shtml
Hydro Quebec	4/1/2017	http://www.hydroquebec.com/publications/en/docs/distribution-tariff/electricity-rates.pdf
Nova Scotia Power Flat	1/1/2017	http://www.nspower.ca/en/home/for-my-home/make-your-own-energy/enhanced-net-metering/default.aspx http://www.nspower.ca/site/media/Parent/Regulation.3.6.Net.Metering.pdf
Newfoundland Power	7/1/2017	http://www.newfoundlandpower.com/aboutus/electricalrates/default.aspx
New Brunswick Power	4/1/2017	https://www.nbpower.com/en/products-services/net-metering/
ATCO Electric Yukon	9/1/2017	http://www.atcoelectricyukon.com/Documents/Regulatory/YECL%20YEC%20Rate%20Schedules%20Sept%202017.pdf http://www.atcoelectricyukon.com/Rates-and-Regulations/
BC Hydro	4/1/2017	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/bchydro-electric-tariff.pdf https://www.bchydro.com/accounts-billing/rates-energy-use/electricity-rates.html
ATCO Electric Alberta	12/21/2016	http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/ATCOElectric-2017RateSchedules-April1-2017.pdf http://www.energy.alberta.ca/Electricity/microgen.asp https://www.aeso.ca/downloads/Guide_for_Distribution_Generation_Fact_Sheet_020311.pdf http://www.atcoelectric.com/Rates/tariffs/Current-Tariffs
FortisAlberta	12/21/2016	http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/Fortis-RateSchedule.pdf http://www.energy.alberta.ca/Electricity/microgen.asp http://fortisalberta.com/customer-service/rates-and-billing/rates-options-and-riders https://www.aeso.ca/downloads/Guide_for_Distribution_Generation_Fact_Sheet_020311.pdf

Appendix B

DRAFT ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
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P: 604.660.4700
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ORDER NUMBER
G-xx-xx

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:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

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

B. On [DATE, 2018], the Commission held a procedural conference to address, among other things, the process and timetable for the review of the Application;

C. On [DATE, 2018], the Commission issued Order G-XX-2018 establishing a written hearing process; and

D. The Commission has reviewed and considered the Application, the evidence filed, and the submissions provided by all participants, and has determined that the requested changes, as outlined in the Application, should be approved.

NOW THEREFORE the Commission orders as follows:

1. The following rate design proposals for Rate Schedule 1 is approved:

   - 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 is approved.
3. The following rate design proposal for Rate Schedule 20 is approved:
   - 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. The following rate design proposals for Rate Schedule 21 are approved:
   - 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.
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 Rate Schedule 31 are approved:
   - 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. The following rate design proposals for Rate Schedule 60 are approved:
   - 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.
   - A change to the Rate description to facilitate non-TOU Irrigation customers to be charged Commercial TOU rates during the non-irrigation season.
8. The addition of a discount for RS 40 customers that take delivery at Transmission voltage is approved.
9. The revised structure of existing optional TOU rate schedules is approved.
10. The following rate design proposal for Transmission Service Rates are approved:
    - Removal of RS 102 from the Electric Tariff.
    - 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.

11. The following proposals for the Electric Tariff are approved:
    - Amendments to FBC's General Terms and Conditions as set out in the Application.
    - 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).
12. FBC is directed to file with the Commission amended tariff pages in accordance with the terms of this order to be effective January 1, 2019.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Appendix C
DRAFT PROCEDURAL ORDER

bcuc
British Columbia
Utilities Commission

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Vancouver, BC Canada V6Z 2N3
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ORDER NUMBER
G-xx-xx

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:
Panel Chair/Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

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

B. Prior to the Application, FBC conducted a stakeholder engagement process consisting of information sessions and stakeholder workshops;

C. FBC believes the Application can be addressed efficiently and effectively by a written hearing process;

D. The Commission has determined that a public hearing is appropriate to review the Application and that a public hearing process should be commenced, a regulatory timetable should be established and a public notice should be issued.

NOW THEREFORE the British Columbia Utilities Commission orders as follows:

1. A public hearing process is established for the review of the FortisBC Inc. (FBC) Cost of Service Analysis and Rate Design Application (Application) in accordance with the regulatory timetable set out in Appendix A to this order.

2. As soon as reasonable possible, FBC is to publish the Application, this order and the regulatory timetable on its website and to provide a copy of the Application and this order to:

    a. All invitees and attendees of the stakeholder engagement process; and

b. Registered interveners in the FBC Annual Review for 2018 Rates proceeding.

3. By no later than [DATE], FBC is to publish the Public Notice, attached as Appendix B to this Order, in such local newspapers as to provide adequate notice to those parties who may have an interest in or be affected by the Application.

4. The Application, together with any supporting materials, will be available for inspection at the FBC Office, Suite 100, 1975 Springfield Road, Kelowna, BC V1Y 7V7. The Application and supporting materials also will be available on the FortisBC website at www.fortisbc.com and on the Commission website at www.bcuc.com.

5. Interveners who wish to participate in the regulatory proceeding are to register with the Commission by completing a Request to Intervene Form, available on the Commission's website at http://www.bcuc.com/Registration-Intervener-1.aspx by the date established in the Regulatory Timetable attached as Appendix A to this order and in accordance with the Commission's Rules of Practice and Procedure attached to Order G-1-16.

6. Participants intending to apply for Participant Assistance/Cost Award (PACA) exceeding $10,000 must file a completed PACA Budget Estimate form by [DATE]. PACA applications should be consistent with the Commission's PACA Guidelines and Order G-97-17. Copies of the PACA Guidelines are available upon request or can be downloaded from the Commission's website at http://www.bcuc.com.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of [Month Year].

BY ORDER

Original signed by:

(X. X. last name)
Commissioner

Attachments

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

REGULATORY TIMETABLE

ACTION	DATE (2018)
FBC publishes Public Notice	
Registration of Interveners	Friday, January 19
Deadline for Submitting Participant Assistance/Cost Award Budgets	
Commission Information Request (IR) No. 1	Friday, February 16
Intervener IR No. 1	Friday, March 2
FBC Response to IR No. 1	Friday, April 6
Commission and Intervener IR No. 2	Friday, April 20
FBC Responses to IR No. 2	Friday, May 11
FBC Final Argument	Friday, June 1
Intervener Final Argument	Friday, June 15
FBC Reply Argument	Friday, June 21

PUBLIC NOTICE

[Proceeding Name]

The Commission is initiating a review of FortisBC Inc.'s (FBC) 2017 Cost of Service Analysis and Rate Design Application, which was filed on December 22, 2017. FBC seeks to review its existing rate design and proposes a limited number of changes to rates in response to changes in the needs and circumstances of certain rate classes.

HOW TO PARTICIPATE

There are a number of ways to participate in a matter before the Commission:

- **Submit a letter of comment**
- **Register as an interested party**
- **Request intervener status**

For more information, or to find the forms for any of the options above, please visit our website or contact us at the information below.

www.bcuc.com/RegisterIndex.aspx

All submissions received, including letters of comment, are placed on the public record, posted on the Commission's website and provided to the Panel and all participants in the proceeding.

NEXT STEPS

Intervener registration Persons who are directly or sufficiently affected by the Commission's decision or have relevant information or expertise, and that wish to actively participate in the proceeding can request intervener status by submitting a completed Request to Intervene Form by Friday, January 19, 2018.

GET MORE INFORMATION

All documents filed on the public record are available on the "Current Proceedings" page of the Commission's website at www.bcuc.com.

If you would like to review the material in hard copy, or if you have any other inquiries, please contact Laurel Ross, Acting Commission Secretary, at the following contact information.

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Email: Commission.Secretary@bcuc.com
Phone: 604-660-4700
Toll Free: 1-800-663-1385

Appendix D

DERIVATION OF STANDARD CHARGES

FORTISBC

FORTISBC INC.

2017 COSA and RDA

Appendix A – Derivation of Standard Charges

December 2017

Table of Contents

1. SECTION 17.1 - INSTALLATION OF NEW/UPGRADED SERVICES

1.1 OVERHEAD SINGLE PHASE – NEW CONNECTION OR UPGRADE 200 AMPS OR LESS

Based on system weighted average times[1] and costs for FBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 2 Power Line Technician	
Labour	- 1.5 hours site time + 1.0 hours travel time	
	= 2.5 hours	
Crew Labour (including loadings)		
	= 4 hours x $77.80 (standard labour rate)	= $311.20
Admin	- 1 admin staff	
Labour	- 0.75 hours	
Admin labour (including loadings)		
	= 0.75 hours x $56.25 (standard labour rate)	= $42.18
Total Labour		**= $353.38**
Vehicle Cost		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 2.5 hours x $25.04 (vehicle rate)	= $62.60
Material Cost – 30m #2 triplex & related items		
	= $125.58 + 10% loadings	= $138.14
Subtotal		**= $554.12**
Overhead loadings = 33.4% x $554.12		= $185.08
TOTAL FOR SERVICE		**= $739.20**
Rounded		**= $739**

Note: Minor differences due to rounding.

[1] Average crew travel and work times are weighted based on FBC's urban versus rural service area characteristics.

1.2 Underground Single Phase – New Connection or Upgrade 200 Amps or Less

Based on system weighted average times and costs for FortisBC's service area:

<u>Total labour (standard labour rates including loadings)</u>

Crew	- 2 Power Line Technician	
Labour	- 1.5 hours site time + 1.0 hours travel time	
	= 2.5 hours	
Crew Labour (including loadings)		
	= 4 hours x $77.80 (standard labour rate)	= $311.20
Admin	- 1 admin staff	
Labour	- 0.75 hours	
Admin labour (including loadings)		
	= 0.75 hours x $56.25 (standard labour rate)	= $42.18
Total Labour		**= $353.38**
<u>Vehicle Cost</u>		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 2.5 hours x $25.04 (vehicle rate)	= $62.60
<u>Material Cost</u> – 30m 1/0 cable & related items		
	= $169.41 + 10% loadings	= $186.35
Subtotal		**= $602.33**
Overhead loadings = 33.4% x $602.33		= $201.18
TOTAL FOR SERVICE		**= $803.51**
Rounded		**= $804**

Note: Minor differences due to rounding.

2. SECTION 17.2 - CONNECTION CHARGES

2.1 *Meter Connection, Manual Reconnection of a Meter After Disconnection for Violation of Terms and Conditions, OR Meter Test*

Based on system weighted average times and costs for FBC's service area:

<u>Total labour (standard labour rates including loadings)</u>

Crew	- 1 Power Line Technician	
Labour	- 0.25 hours site time + 0.60 hours travel time	
	= 0.85 hours	
Crew Labour (including loadings)		
	= 0.85 hours x $77.80 (standard labour rate)	= $66.13
Admin	- 1 admin staff	
Labour	- 0.25 hours	
Admin labour (including loadings)		
	= 0.25 hours x $56.25 (standard labour rate)	= $14.07
Total Labour		**= $80.20**
<u>Vehicle Cost</u>		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 0.85 hours x $25.04 (vehicle rate)	= $21.28
Subtotal		**= $101.48**
Overhead loadings = 33.4% x $101.48		= $33.90
TOTAL FOR SERVICE		**= $135.38**
Rounded		**= $135**

Note: Minor differences due to rounding.

2.2 METER CONNECTION, MANUAL RECONNECTION OF A METER AFTER DISCONNECTION FOR VIOLATION OF TERMS AND CONDITIONS, OR METER TEST – PERFORMED DURING OVERTIME HOURS

Based on system weighted average times and costs for FortisBC's service area:

Total labour (overtime labour rates including loadings)		
Crew	- 1 Power Line Technician	
Labour	- 0.25 hours site time + 0.60 travel time	
	= 0.85 hours	
Crew Labour (including loadings)		
	= 0.85 hours x $122.51 (overtime labour rate)	= $104.13
Admin	- 1 admin staff	
Labour	- 0.25 hours	
Admin labour (including loadings)		
	= 0.25 hours x $ 56.25 (standard labour rate)	= $14.06
Total Labour		**= $118.20**
Vehicle Cost		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 0.85 hours x $25.04 (vehicle rate)	= $21.28
Subtotal		**= $139.49**
Overhead loadings (excluding overtime labour)		
	= 33.4% x $139.49	= $46.59
TOTAL FOR SERVICE		**= $224.09**
Rounded		**= $224**

Note: Minor differences due to rounding.

2.3 METER CONNECTION, MANUAL RECONNECTION OF A METER AFTER DISCONNECTION FOR VIOLATION OF TERMS AND CONDITIONS, OR METER TEST – PERFORMED DURING CALLOUT HOURS

Based on system weighted average times and costs for FBC's service area:

<u>Total labour (standard labour rates including loadings)</u>		
Crew	- 1 Power Line Technician	
Labour	- 4 hours site time & travel time (minimum 4 hour)	
	= 4 hours	
Crew Labour (including loadings)		
	= 4 hours x $77.80 (standard labour rate)	= $311.20
Admin	- 1 admin staff	
Labour	- 0.25 hours	
Admin labour (including loadings)		
	= 0.25 hours x $56.25 (standard labour rate)	= $14.06
Total Labour		**= $325.24**
<u>Vehicle Cost</u>		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 0.85 hours x $25.04 (vehicle rate)	= $21.28
Subtotal		**= $346.52**
Overhead loadings = 33.4% x $346.52		= $115.74
TOTAL FOR SERVICE		**= $462.26**
Rounded		**= $462**

Note: Minor differences due to rounding.

2.4 *ADDITIONAL METER CONNECTION OR MANUAL RECONNECTION*

Based on system weighted average times and costs for FBC's service area:

<u>Total labour (standard labour rates including loadings)</u>		
Crew	- 1 Power Line Technician	
Labour	- 0.25 hours site time	
	= 0.25 hours	
Crew Labour (including loadings)		
	= 0.25 hours x $77.80 (standard labour rate)	= $19.45
Total Labour		**= $19.45**
<u>Vehicle Cost</u>		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 0.25 hours x $25.04 (vehicle rate)	= $6.26
Subtotal		**= $25.71**
Overhead loadings = 33.4% x $25.71		= $8.58
TOTAL FOR SERVICE		**= $34.29**
Rounded		**= $34**

Note: Minor differences due to rounding.

2.5 REMOTE RECONNECTION OF A METER AFTER DISCONNECTION FOR VIOLATION OF TERMS AND CONDITIONS

Based on system weighted average times and costs for FBC's service area:

1	**Collections Activities** (review account, negotiate payment arrangements and complete reconnection)		
2	Approximate Admin Time (minutes)	10	
3	Fully Loaded Hourly Rate	$56.25	
4	Average Cost per Interaction	$9.38	(Line 3/60) * Line 2
6	**Billing Activities** (review and process bill adjustments and payments)		
7	Approximate Admin Time (minutes)	5	
8	Fully Loaded Hourly Rate	$39.55	
9	Average Cost per Interaction	$3.30	(Line 7/60) * Line 8
10	Average Cost of Remote Meter Reconnection	$12.67	Line 4 + Line 10
7	**Rounded**	**$13.00**	

2.6 *DISCONNECTION AND RECONNECTION OF METER*

Based on system weighted average times and costs for FBC's service area:

<u>Total labour (standard labour rates including loadings)</u>		
Crew	- 1 Power Line Technician	
Labour	- 0.5 hours site time + 1.2 hours travel time	
	= 1.7 hours	
Crew Labour (including loadings)		
	= 1.7 hours x $77.80 (standard labour rate)	= $132.26
Admin	- 1 admin staff	
Labour	- 0.5 hours	
Admin labour (including loadings)		
	= 0.5 hours x $ 56.25 (standard labour rate)	= $28.13
Total Labour		**= $160.39**
<u>Vehicle Cost</u>		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 1.7 hours x $25.04 (vehicle rate)	= $42.57
Subtotal		**= $202.96**
Overhead loadings = 33.4% x $202.96		= $67.79
TOTAL FOR SERVICE		**= $270.75**
Rounded		**= $271**

Note: Minor differences due to rounding.

2.7 RELOCATION OF EXISTING OVERHEAD SERVICE

Based on system weighted average times and costs for FBC's service area:

Total labour (standard labour rates including loadings)

Crew	- 1 Power Line Technician	
Labour	- 3 hours site time + 2 hours travel time	
	= 5 hours	
Crew Labour (including loadings)		
	= 5 hours x $77.80 (standard labour rate)	= $389.00
Admin	- 1 admin staff	
Labour	- 0.75 hours	
Admin labour (including loadings)		
	= 0.75 hours x $56.25 (standard labour rate)	= $42.19
Total Labour		**= $431.19**
Vehicle and Material Cost		
Vehicle Use	- 1 Bucket Service truck	
Vehicle Use	- 5 hours x $43.30 (vehicle rate)	= $216.50
Material	- Connectors	
	= $26.16 + 10% loadings	= $28.78
Subtotal		**= $676.47**
Overhead loadings = 33.4% x $676.47		= $225.94
TOTAL FOR SERVICE		**= $902.41**
Rounded		**= $902**

Note: Minor differences due to rounding.

3. SECTION 17.3 - MISCELLANEOUS STANDARD CHARGES

3.1 ACCOUNT SETUP CHARGE

Based on actual 2016 labour and costs:

1	Total number of applications charged for new service and changes to existing accounts (moves) in 2016	19,981	
2	Customer Service labour costs related to processing applications for new service and changes to accounts including non-communicating off-cycle moves	$151,114	
3	Average Customer Service labour cost related to processing applications for new service and changes to accounts	$7.56	Line 2 / Line 1
4	Equifax credit check and ID validation cost per transaction	$5.25	
5	Off-cycle move-in/move-out communicating meter cost per transaction	$ -	
6	**Total Application Cost**	**$12.81**	Line 6 + Line 8 + Line 10
7	**Rounded**	**$13.00**	

Note: Minor differences due to rounding.

3.2 RETURNED PAYMENT SERVICE CHARGE

Based on actual 2016 labour and costs:

1	Returned payments	89	
2	Returned preauthorized payment plan transactions	714	
3	Total returned payments	803	Line 1 + Line 2
4	Bank charges – weighted average per returned payment	$5.17	
5	Total bank charge cost	$4,149	Line 4 * Line 3
6	Finance Department average processing cost per returned item	$2.33	
7	Total Finance Department cost	$1,868	Line 6 * Line 3
8	Customer Service average processing cost per returned item	$5.11	
9	Total Customer Service cost	$4,103	Line 8 * Line 3
10	Total Cost of returned items	$10,119	Line 5 + Line 7 + Line 9
11	Total Cost per returned item	$12.61	Line 10 / Line 3
12	**Rounded**	**$13**	

Note: Minor differences due to rounding.

3.3 METER ACCESS CHARGE (REMOTE METER – SINGLE PHASE)

Based on system weighted average times and costs for FBC's service area:

Total labour (standard labour rates including loadings)		
Crew	- 1 Power Line Technician	
Labour	- 0.25 hours site time + 0.60 hours travel time	
Labour (including loadings)		
	= 0.85 hours x $77.80 (standard labour rate)	= $66.13
Admin	- 1 admin staff	
Labour	- 0.25 hours	
Admin labour (including loadings)		
	= 0.25 hours x $56.25 (standard labour rate)	= $14.06
Total Labour		**= $80.18**
Vehicle and Material Cost		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 0.85 hours x $25.04 (vehicle rate)	= $21.28
Material	- Incremental single phase meter	
	= $48.41 + 10% loadings	= $53.25
Subtotal		**= $154.71**
Overhead loadings = 33.4% x $154.71		= $51.67
TOTAL FOR SERVICE		**= $206.38**
Rounded		**= $206**

Note: Minor differences due to rounding.

3.4 METER ACCESS CHARGE (REMOTE METER – POLY PHASE)

Based on system weighted average times and costs for FBC's service area:

<u>Total labour (standard labour rates including loadings)</u>

Crew	- 1 Power Line Technician	
Labour	- 0.25 hours site time + 0.60 hours travel time	
Labour (including loadings)		
	= 0.85 hours x $77.80 (standard labour rate)	= $66.13
Admin	- 1 admin staff	
Labour	- 0.25 hours	
Admin labour (including loadings)		
	= 0.25 hours x $56.25 (standard labour rate)	= $14.06
Total Labour		**= $80.18**
<u>Vehicle and Material Cost</u>		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 0.85 hours x $25.04 (vehicle rate)	= $21.28
Material	- Incremental single phase meter	
	= $193.48 + 10% loadings	= $212.83
Subtotal		**= $314.29**
Overhead loadings = 33.4% x $314.29		= $104.98
TOTAL FOR SERVICE		**= $419.27**
Rounded		**= $419**

Note: Minor differences due to rounding.

3.5 *FALSE SITE VISIT CHARGE*

Based on system weighted average times and costs for FBC's service area:

<u>Total labour (standard labour rates including loadings)</u>		
Crew	- 1.5 Power Line Technicians	
Labour	- 0.3 hours site time + 1 hours travel time	
	= 1.95 hours	
Crew Labour (including loadings)		
	= 1.95 hours x $77.80 (standard labour rate)	= $151.70
Total Labour		**= $151.70**
<u>Vehicle and Material Cost</u>		
Vehicle Use	- 1 Service truck	
Vehicle Use	- 1.30 hours x $25.04 (vehicle rate)	= $32.55
Subtotal		**= $184.25**
Overhead loadings = 33.4% x $184.25		= $61.54
TOTAL FOR SERVICE		**= $245.79**
Rounded		**= $246**

Note: Minor differences due to rounding.

3.6 TEMPORARY SERVICE TO PERMANENT OR SALVAGE OF TEMPORARY SERVICE

Based on system weighted average times and costs for FBC's service area:

<u>Total labour (standard labour rates including loadings)</u>

Crew	- 1 Power Line Technician	
Labour	- 0.5 hours site time + 1 hours travel time	
	= 1.5 hours	
Crew Labour (including loadings)		
	= 1.5 hours x $77.80 (standard labour rate)	= $116.70
Admin	- 1 admin staff	
Labour	- 0.333 hours	
Admin labour (including loadings)		
	= 0.333 hours x $56.25 (standard labour rate)	= $18.75
Total Labour		**= $135.45**
<u>Vehicle and Material Cost</u>		
Vehicle Use	- 1 Bucket Service truck	
Vehicle Use	- 1.5 hours x $43.30 (vehicle rate)	= $64.95
Subtotal		**= $200.40**
Overhead loadings = 33.4% x $174.15		= $66.94
TOTAL FOR SERVICE		**= $267.35**
Rounded		**= $267.00**

Note: Minor differences due to rounding.

4. SECTION 18 - RADIO-OFF ADVANCED METER OPTION

4.1 *PER-READ FEE*

Based on actual 2017 Radio-off customers, and actual and forecast 2017 labour and costs:

1	Number of Radio-off meters	2,691	
2	Number of reads per year	16,146	Line 1 * 6
3	Total labour to read radio-off meters	$384,000	
4	Cost per read	$23.80	Line 3 / Line 2
6	AMI Radio-off Shortfall Deferral Account Balance per read	$1.48	($120,000 / 5) / Line 2
7	Cost per read with Shortfall Collection	$25.28	Line 4 + Line 6
6	**Rounded**	**$25**	

Note: Minor differences due to rounding.

Appendix E

CONSULTATION MATERIALS

Discussion Guide – FortisBC June Workshops

Your views are important to us

FortisBC is seeking public and First Nations input as we complete a review of cost of service and rate design to make sure rates charged to customers are fair and equitable.

All utilities must review cost of service and rate design periodically to make sure rates reflect the fair and equitable allocation of costs. A Cost of Service Analysis (COSA) determines the cost of providing electrical service by customer class and rate design evaluates various rate structures. Rate structures direct how customers are billed for their electricity use.

Overall, any changes resulting from COSA and rate design do not generate more revenue for a utility. Any changes proposed will be aimed at making sure rates paid by a given customer class reflect the cost of providing service to those customers, and that classes of customers are not unduly subsidizing each other

FortisBC is committed to open dialogue with customers, stakeholders and First Nations. We believe your feedback is an important part of the process as FortisBC completes a 2017 COSA and rate design review. Please share your thoughts on these topics with us.

Input gathered from our consultation activities will be compiled and included in FortisBC's final COSA filing and rate design application to the British Columbia Utilities Commission (the BCUC).

Public consultation and regulatory process

FortisBC is committed to consultation, information sharing and building long-term cooperative relationships.

In the process of developing its rate design proposals, FortisBC is hosting public open houses and meetings with First Nations, customers and municipalities within our service territory. When this initial consultation is complete, FortisBC will provide a preliminary draft of the COSA results and rate design proposals for further input and discussion. Additional feedback from public and First Nations on this draft will be accepted until September 30, 2017. This input will be considered as FortisBC prepares the its final rate design proposals, expected to be filed with the BCUC by the end of 2017.

A series of open houses are being held across FortisBC's service area to invite public input. For those unable to attend an open house, FortisBC is also providing opportunities for input through an online feedback form available on our website at http://www.fortisbc.com/electricityratedesign. Submissions can also be sent to our regulatory affairs department by:

Email: electricity.regulatory.affairs@fortisbc.com

Mail: Corey Sinclair, at 1975 Springfield Rd, Kelowna, BC, V1Y 7V7

All input must be received by September 30, 2017 in order to be considered for the final 2017 COSA Rate Design Application.

Feedback received from this consultation will be considered, along with technical and financial information, as FortisBC prepares its Application for submission to the BCUC. Once the COSA and RDA have been filed, the BCUC manages the regulatory process and will make the final decision regarding the rate design(s) to be implemented.

The BCUC will set a schedule for a regulatory review process of both the Application by the BCUC and interested parties.

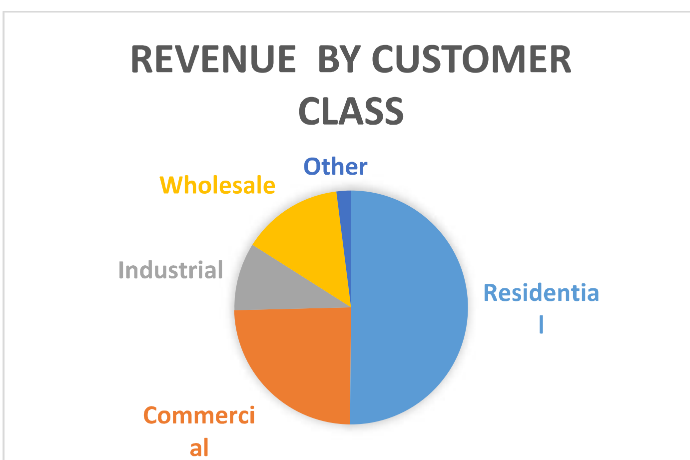
For more information on the BCUC, visit www.bcuc.com.

Customer classes

Customer classes, or customer groups as they are also known in the utility sector, include residential, commercial, large commercial (industrial), wholesale, lighting and irrigation. Each group has different characteristics and different requirements for service from the utility.

For example, a residential customer requires generation of electricity, transmission and distribution of electricity, and customer services such as billing and meter reading. A large industrial customer typically requires only generation and transmission of bulk electricity but does not use the distribution system. Each customer group should pay its "fair share" of the total cost to operate the utility.

The portion of total annual revenue provided by each customer class is shown below.



Cost of service analysis and rate design

Rate setting involves three steps.

The first step is to establish the revenue requirement, a review that is done annually to determine the total cost of operating the utility each year.

Steps two and three are the focus of the 2017 COSA and Rate Design consultation.

- Cost of service analysis – completed periodically to determine the costs each customer class is causing and compare these costs to how much revenue the utility is collecting from each group. The COSA is a critical step in setting fair and equitable rates for customer groups, with the goal of ensuring that each customer group is paying the appropriate portion of the total costs of operating the utility.

- Rate design – reviewed periodically to determine how the utility recovers costs from customers. Rate design evaluates rate structures, the basic customer charge and the terms and conditions of electrical service.

Both cost of service analysis and rate design are revenue neutral to FortisBC, meaning that they do not change the total revenue collected from customers. They merely distribute the costs and revenue amongst the customer groups.

COSA and Rate Design principles

Utilities throughout North America and the world generally follow an established methodology in conducting a COSA. Each utility will assign costs to customers differently to reflect the unique attributes of service in each utility service area. As FortisBC works through the COSA and Rate Design process, it strives to ensure that:

- Customer feedback is reflected;
- Rates are simple and easy to understand;
- Rates reflect costs to the utility – both fixed and variable;
- Rate impact is managed for the majority of customers;
- Rates reflect provincial energy policy and legislation;
- Rate structures encourage energy efficiency and conservation; and
- New rate structures are only introduced if they meet long-term needs.

Rate rebalancing

The COSA is used to evaluate whether that all customer groups are paying their fair share of the cost of electrical service. The draft COSA will contain an assessment of the extent to which each customer class is paying an appropriate amount relative of the cost to serve them. If it is the case that certain customer groups are paying more or less than they should relative to the cost of serving them, a rate adjustment, or “rebalancing” may be required. Should this be the case, FortisBC will present a plan for rebalancing that will also be the subject of customer consultation.

Next steps

All feedback received will be considered, along with technical and financial information, as FortisBC prepares its Application for submission to the BCUC. Once the Application has been filed, the BCUC manages the regulatory process and will make the final decision regarding the rate design(s) to be implemented.

The BCUC will set a schedule for a regulatory review process of the Application. For more information on the BCUC, visit www.bcuc.com.

Please leave us with your feedback

If you would like to be advised of activity related to the 2017 COSA and Rate Design, please provide the information below:

Name:____

Address:____

Email Address:____

FORTIS BC™

FortisBC 2017 Rate Design Consultation

Fact Sheet/ Questions & Answer's

June, 2017

Background

FortisBC is hosting a series of open houses in June - to provide information and gather public feedback into the Company's 2017 cost of service analysis (COSA) and rate design review currently underway.

The Company is completing this review of how existing electricity rates are structured for all customers—residential, commercial, industrial, wholesale, lighting and irrigation—which will help determine whether updates to rate structures are needed. Public input into this review is an important part of the process and will provide valuable information on what factors are important to our customers.

In July, follow-up open houses and customer meetings will be held throughout the region to further discuss rate options and provide the feedback to the attendees from the June open houses participants. Following these open houses, FortisBC will file a draft COSA report with the British Columba Utilities Commission (BCUC).

The next step for FortisBC is the rate design review currently underway. The upcoming open houses will start with a presentation from the BCUC at 6:00 p.m. followed by FortisBC presentation starting at 6:30 p.m. to 8:30 p.m.
Open houses will be hosted in:

- Public open house
  - Kelowna - June 27 6:00pm – 8:30pm Sandman Hotel
  - Osoyoos – June 28 6:00pm – 8:30pm Watermark beach resort
  - Castlegar – June 29 6:00pm – 8:30pm Sandman Hotel
- Follow-up open house
  - Kelowna - July 25 6:00pm – 8:00pm Sandman Hotel
  - Osoyoos – July 26 6:00pm – 8:00pm Watermark beach resort
  - Castlegar – July 27 6:00pm – 8:00pm Sandman Hotel

All feedback received will be considered, along with technical and financial information, as FortisBC prepares a rate design application for submission to the BCUC in November of 2017. Once the COSA and rate design application have been filed, the BCUC manages the regulatory process and will make the final decision regarding cost of service analysis and rate design(s) to be implemented.

Individuals interested in more information about rate design and these open houses are encouraged to visit www.fortisbc.com or call 1-866-4FORTIS (1-866-436-7847).

Anyone unable to attend an open house in this series but interested in providing input, can visit our website for additional information:

fortisbc.com/electricityratedesign.

Questions & Answers

1. What is COSA?

COSA is an acronym for Cost of Service Analysis. The COSA takes the revenue requirements established for the utility and allocates costs across the various customer classes, with the results used to ensure that proposed rates are fair, equitable and not unduly discriminatory.

The goal of a COSA is to ensure all customers pay their fair share of a utility's total cost of providing service.

2. What is rate design?

Rate design is reviewed periodically to determine how the utility recovers costs from customers. Rate design evaluates rate structures, including the basic customer charge. Both cost of service analysis and rate design are revenue neutral to FortisBC; they merely distribute the cost and revenue among customer groups.

3. Why are you doing a COSA and a rate design review?

All utilities review cost of service and rate design periodically to make sure that rates reflect the fair and equitable allocation of costs. A cost of service analysis determines the cost of providing electrical service by customer class.

4. What does it mean to customers?

COSA – A COSA may have an impact on electrical rates if the results of the study show that the collection of revenue no longer reflects the costs associated with each group of customers or "customer classes".

Since utility rate setting is a zero sum undertaking. All customer classes must pay their fair share or alternatively some customers may pay too little while others would be required to pay too much.

Rate design – Fortis BC's current default residential customer rate is the Residential Conservation Rate (RCR). This structure has three components: a basic charge of $ 32.09/bi-monthly and an energy charge of $0.10117 /kilowatt hour (kWh) for each kWh up to 1,600 bimonthly, and $0.15617 for each kWh above 1,600.

In our 2017 Rate design review, FortisBC may investigate a number of rate structure options for the future and will propose a preferred option in its application after receiving public input and evaluating each option against the goals and principles that guide the rate design process.

5. When was the last COSA done?

2009

6. What will happen with rate rebalancing?

Rate rebalancing may be required in order to address equity across customer classes of existing rates.

The COSA is used to make sure all customer groups are paying their fair share of the cost of electrical service. Ideally, each customer group would show 100 per cent, meaning that they would be paying $1 for every $1 of their cost to the electrical system.

Based on preliminary results produced from sample data, it appears that most customer classes can be considered to be within a reasonable range of cost recovery. FortisBC will make any recommendations regarding rebalancing after further consultation with those customers that may be affected.

Based on this analysis, customer classes over 100 per cent are paying more than their “fair share”, and customers below 100 per cent not paying their “fair share”.

7. What rates options is FortisBC considering?

We will consider rate options based on an examination of options suggested during public consultation, current industry trends, or that arise as a result of the COSA. Regardless of the structure of potential rates, they should ideally be based on the underlying principle of cost-causation. In other words, rates are not created simply because they may be advantageous to certain groups, or to incent certain behaviour, unless they also achieve an outcome that provides a benefit in reduced overall cost to serve or some other desirable objective.

8. My rates just increased in January, will they increase again?

Depending on the rate class that you are in and how the rate design progresses, it is possible that your rates may increase or decrease.

9. What are the next steps?

a. In the public consultation process?
After the conclusion of the public open houses in July, FortisBC will continue to meet with interested customers and post all of its open house materials on the website to facilitate more public feedback.

FortisBC will consider all feedback received, along with technical and financial information, as FortisBC prepares its rate design application for submission to the BCUC in November 2017. Once the COSA and RDA have been filed, the BCUC manages the regulatory process and will make the final decision regarding cost of service analysis and rate design(s) to be implemented.

b. In the regulatory process?
The formal regulatory process will begin after the filing of the final Cost of service Analysis and the Rate Design Application with the BC Utilities Commission in November 2017. This process will examine the rate design option(s) presented by FortisBC as well as the underlying assumptions.

The BCUC will set a schedule for a regulatory review process of both the COSA and RDA, by the BCUC and interested parties. For more information on the BCUC, visit www.bcuc.com.

10. Who decides if the COSA and rate design application is approved?

The COSA is an input into the rate design application. It is the rate design application (RDA) that is actually reviewed, vetted and ultimately approved by the BCUC.

Once the COSA and RDA have been filed, the BCUC manages the regulatory process and will make the final decision regarding cost of service analysis and rate design(s) to be implemented.

11. Where can I get more information / send my comments?

All open house information will be posted on the FortisBC website, as will the draft COSA report. Instructions on submitting input will be on the FortisBC website as well.
fortisbc.com/electricityratedesign.

The formal BCUC process surrounding the rate design application will follow whatever process the Commission decides is appropriate.

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Energy at work

House Keeping Items

- Safety: muster point in case of an evacuation
- First aid attendant
- Washrooms
- Food and Drink
- Sign In Sheet
- Rules of Decorum
- Cellular phones

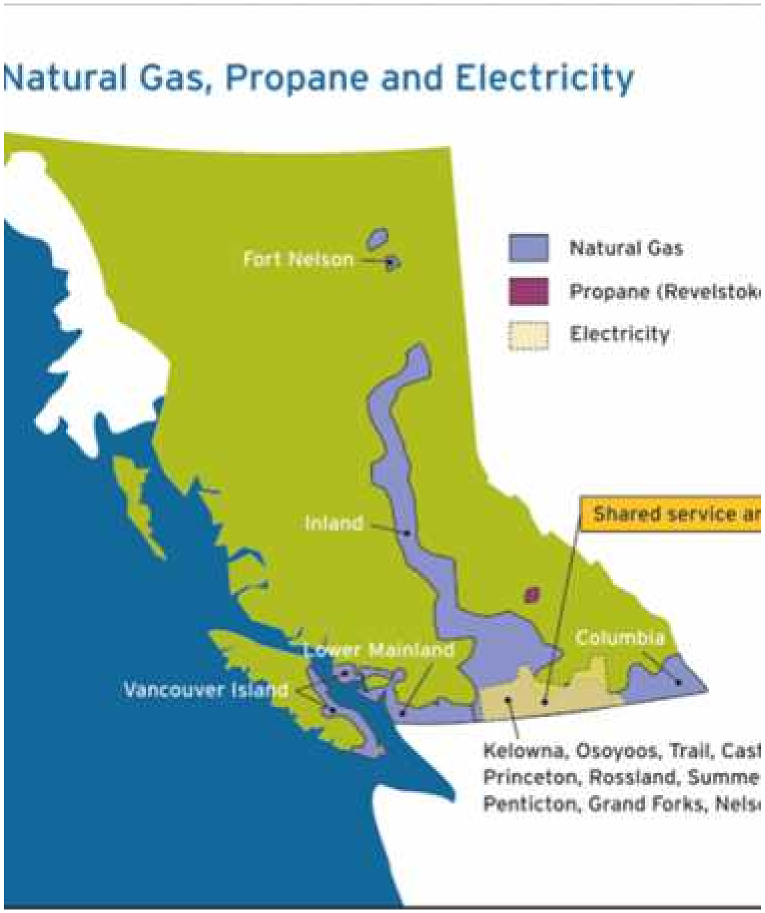
FortisBC Public Consultation

Electricity Rate Design
Open House

Matt Mason, *Community & Aboriginal Relations Manager*
Corey Sinclair, *Manager, Regulatory Affairs*

June 2017

FortisBC - Who We Are



- 100% Canadian owned, and largest investor owned utility in Canada
- Provider of Electricity, Natural Gas, and Propane
- 135 communities, 56 aboriginal communities, more than 1 million customers in BC
- 4 Hydroelectric generating plants
- 2 Liquefied Natural Gas Facilities (LNG)

Public Consultation Goals

1. Provide information to Electricity service area customers about the rate design and application process
2. Positive, interactive, productive workshop
3. Gather public feedback for the rate design application
4. Transparency on the process to the public
5. Communicate results of the feedback and application process to the public

Public Consultation Process

Open houses:

- June 2017 – Introductory / Feedback Session
- July 2017 – Follow-up / Results

Individual Meetings:

- First Nations
- Wholesale customers
- Industrial customers

General Communication:

- Website: FortisBC.com\electricityratedesign

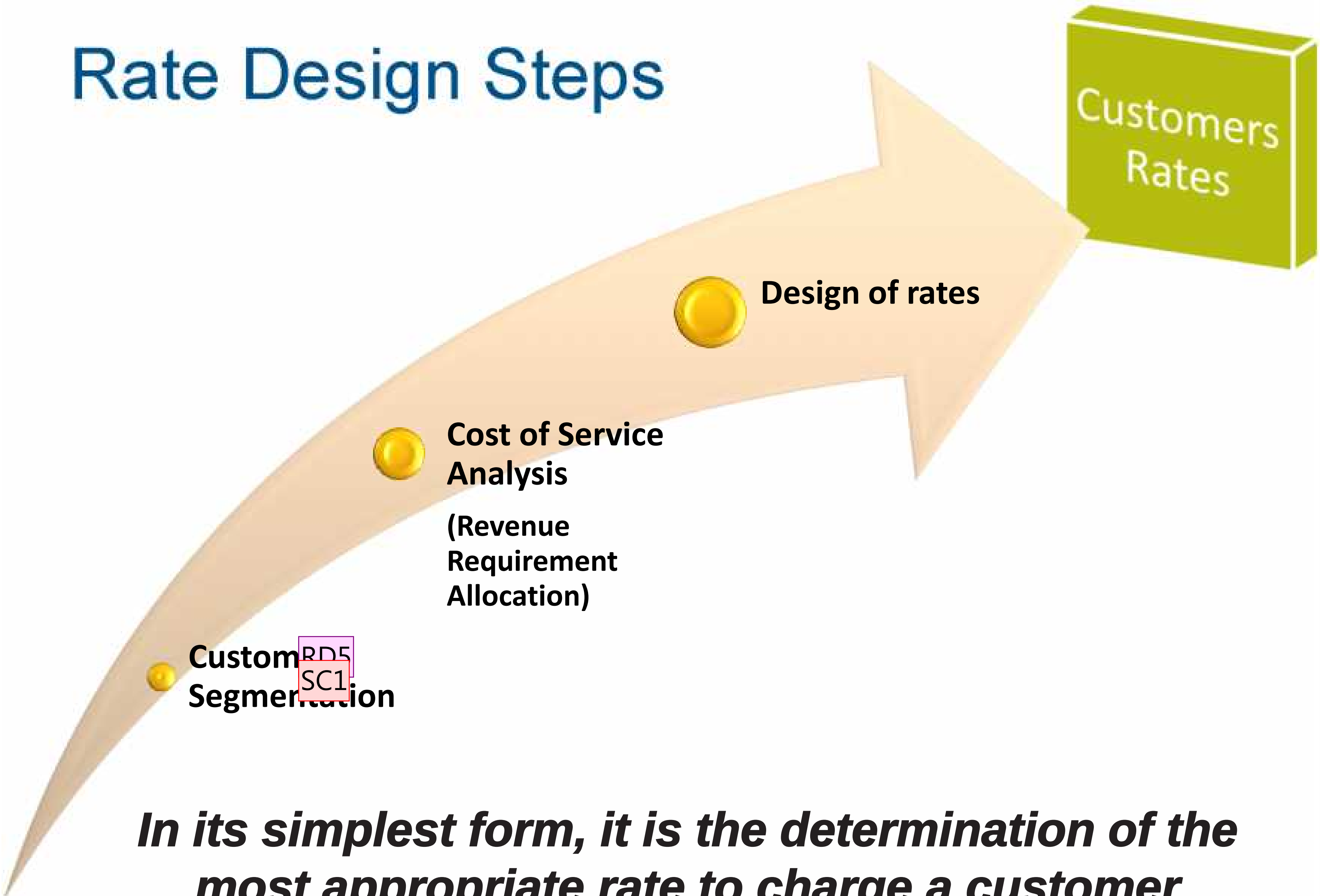
FortisBC Cost of Service Analysis and Rate Design

Public Open House
June 2017

Workshop Agenda

- Explain *Cost of Service Analysis (COSA)* concepts
- Review existing Residential and Small Commercial rates
- Discuss rate options
- Gather input
- Answer questions

Rate Design Steps



In its simplest form, it is the determination of the most appropriate rate to charge a customer group that recovers the costs of serving them

Slide 9

RD5 You have customer segmentation here but you never actually talk about it. Are we going to go through a customer segmentation review in our application?

Roy, Diane, 16/06/2017

SC1 I added this slide from the Gas presentation because I liked the simplicuty of the message (plus it's colourful). My plan is to touch on customer segmentation not as an exercise but only in the fact that the process of dividing customers up into classes has already occured.

Sinclair, Corey, 16/06/2017

What is Cost of Service Analysis and Rate Design?

How we split up the Revenue Requirement amongst customers

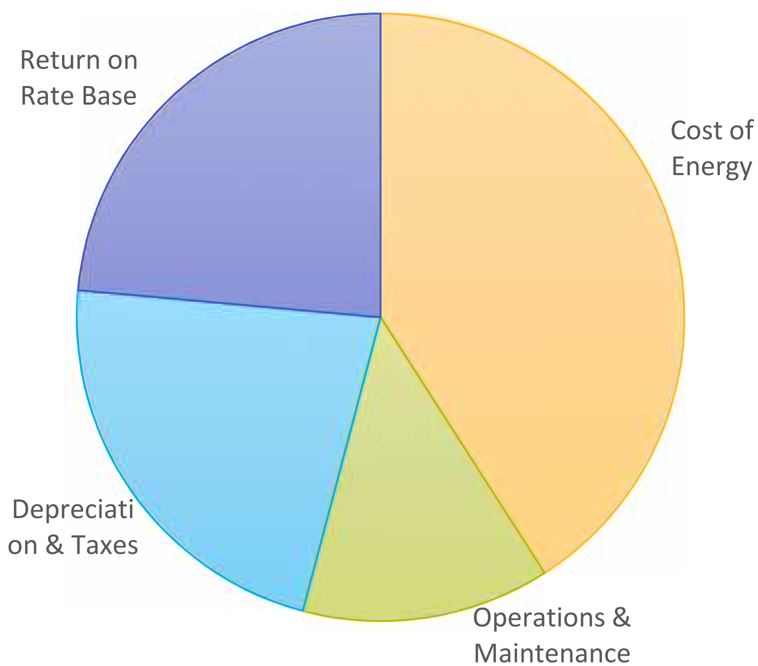
How we design our customer rates

2017 COSA & Rate Design Key Points

1. COSA is an important component in setting fair and equitable rates.
2. COSA, legislation, and public policy set the boundaries for rate setting.
3. Rate Design requires finding a balance of competing objectives.

Key Concept: Revenue Requirement

Revenue Requirement = Cost to Serve



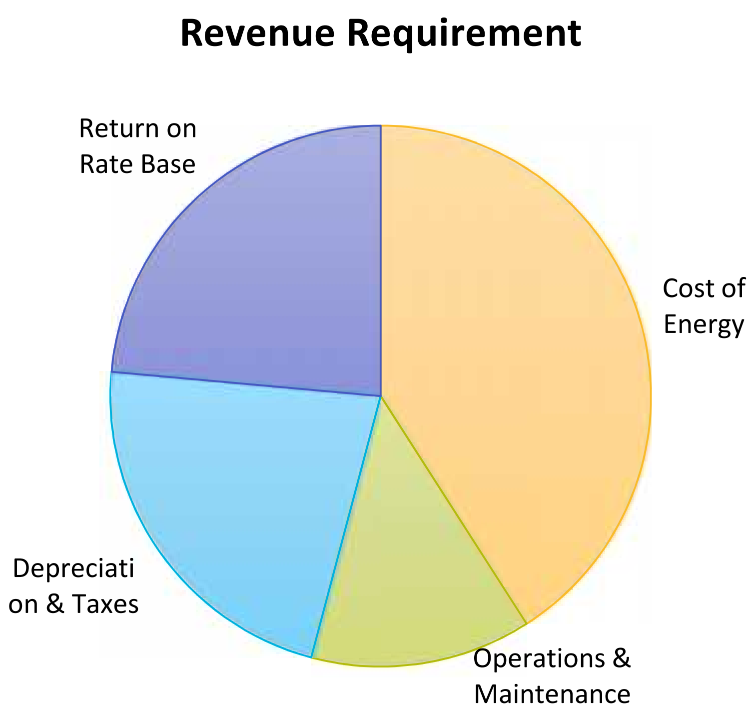
- Determines the revenue required to operate the utility
- Approved annually by the BC Utilities Commission (last completed in 2016 for 2017 rates)
- Basis for annual rate adjustment

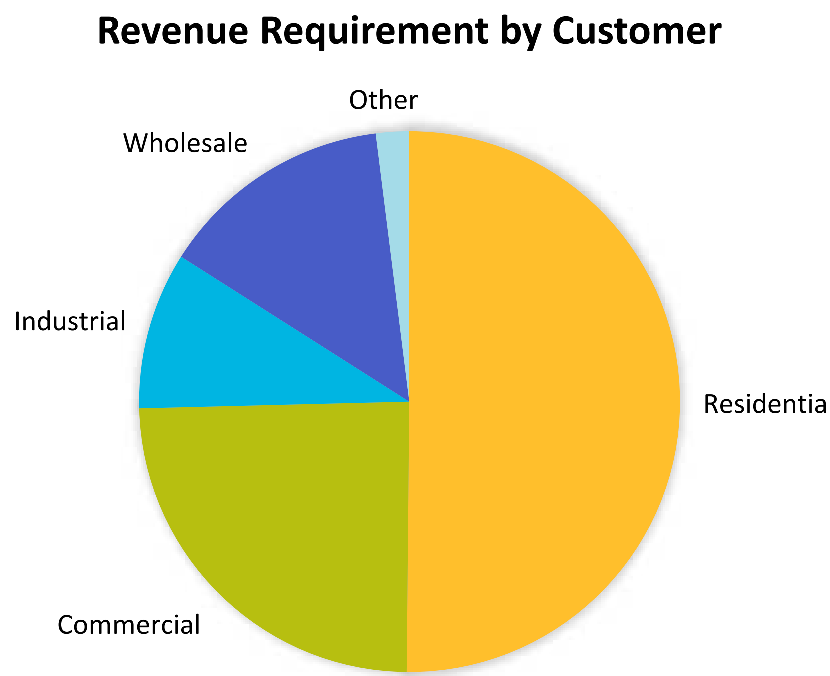
Slide 12

RD1 Not clear why this is here? I know we discussed the concept of rate base but I think you could accomplish that by just changing the label on the pie to "Return on Rate Base"
Roy, Diane, 16/06/2017

SC2 Done.
Sinclair, Corey, 16/06/2017

Slicing the Revenue Requirement Pie





RD2
SC3

Revenue Requirement = The "Size" of the Pie
COSA = How we "Slice" the Pie

Slide 13

RD2 labels on here should be black instead of grey so they are easier to see
Roy, Diane, 16/06/2017

SC3 Done
Sinclair, Corey, 16/06/2017

First Step

Cost of Service Analysis

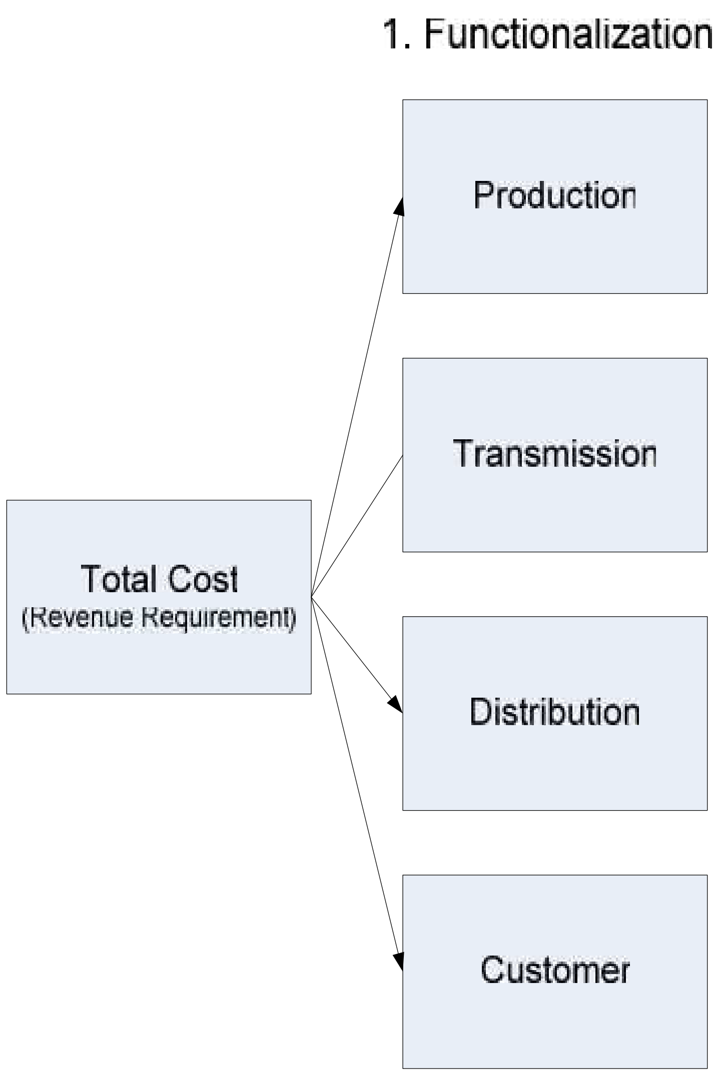
Overview – The COSA Process

Revenue Requirement	➔ *The total dollars to collect.*
Cost of Service Analysis	➔ *Determine costs each customer class is causing and how much revenue the utility should be collecting from each.*
Rate Design	➔ *How does the utility collect the revenues?*

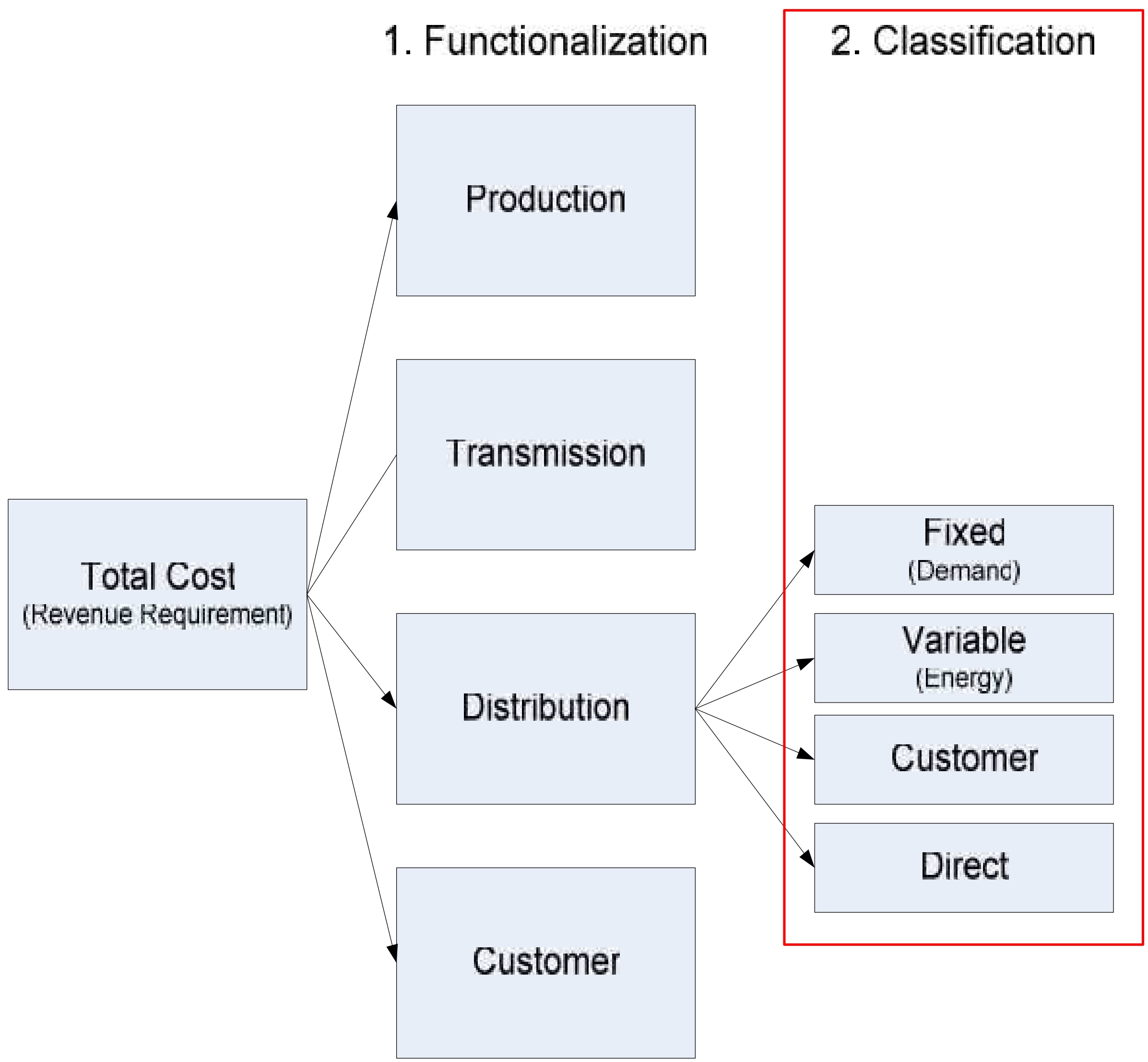
Brief Overview of 3 Steps in COSA

	Determine the revenue requirement of the utility	**Revenue Requirement Determination**
Step 1	**Functionalize costs and services**	**Cost of Service Analysis**
Step 2	**Classify costs**	
Step 3	**Allocate costs among customer classes**	
	Design rates	**Rate Design**

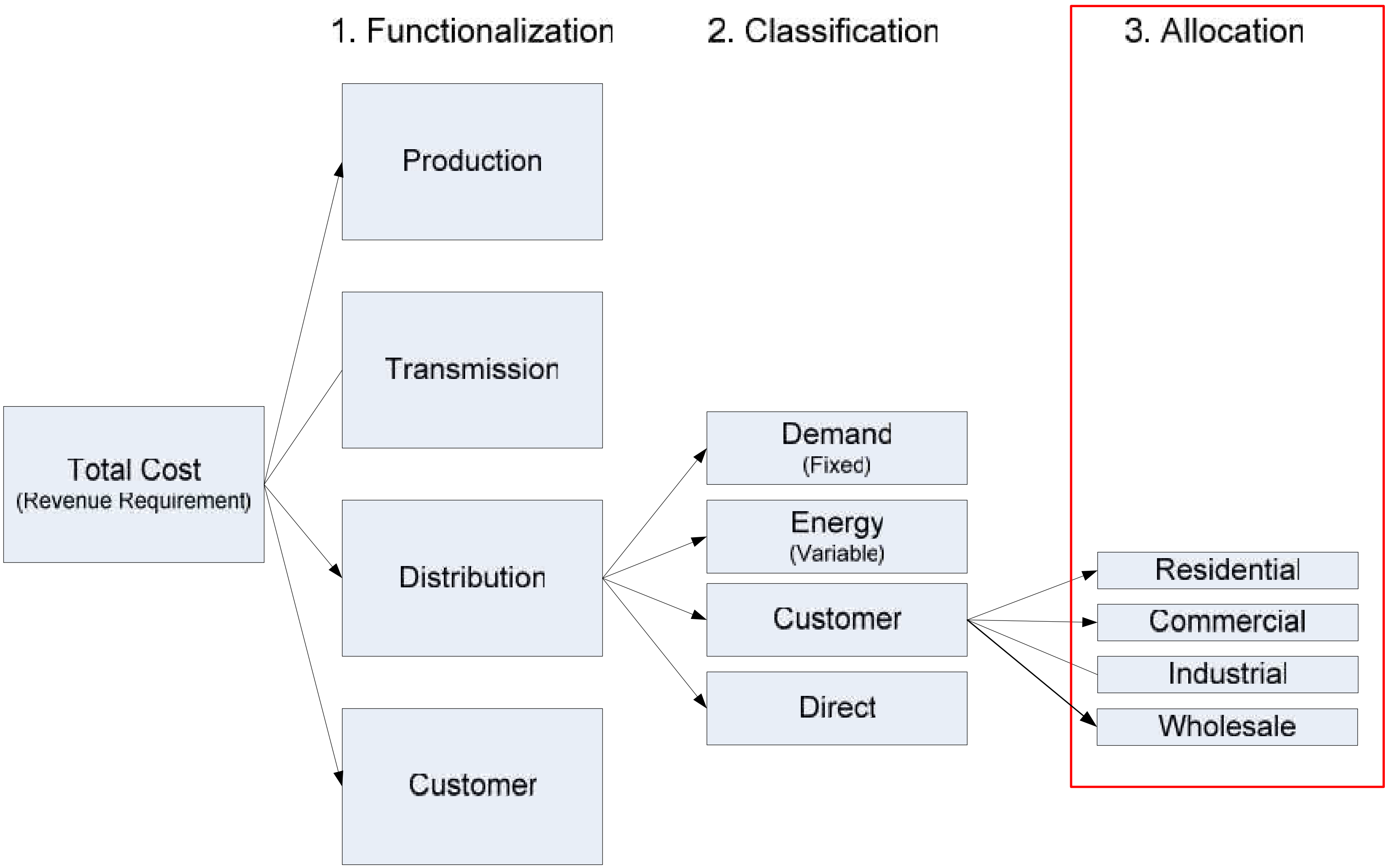
Step 1 - Functionalization



Step 2 – Classification of Costs



Step 3 – Allocation of Costs



Cost Allocation Example

- Cost Allocation is the process of matching the different types of classified costs to different groups of customers.
- Allocation factors apportion the costs on an equitable basis.
- Example:
  - Customer classified costs can be allocated based upon the number of customers in each class of service

Customer Class	Number of Customers	Percentage	Allocated Cost ($)
Residential	94,500	94.5	9,450
Commercial	5,000	5.0	500
Industrial	500	.5	50
	100,000	100	10,000

Example of COSA Results

Revenue to cost ratios are used to show how much customers are paying through their rates relative to the costs that have been allocated in the COSA

Customer Class	2017 Revenue To Cost Ratio
Residential	**102%**
Commercial	**98%**
Industrial	**104%**
Wholesale	**96%**

Range of Reasonableness for Ratios: 95% - 105%

Next Step

Rate Design

Rate Design

Rate Design is the next step after the Cost of Service Analysis is complete

Legal/Policy Considerations:

- *(1) A public utility must not make, demand or receive (a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia,….* UCA Section 59
- Commission is directed to*, "Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation." (2007 Energy Plan – Policy Action 4)*

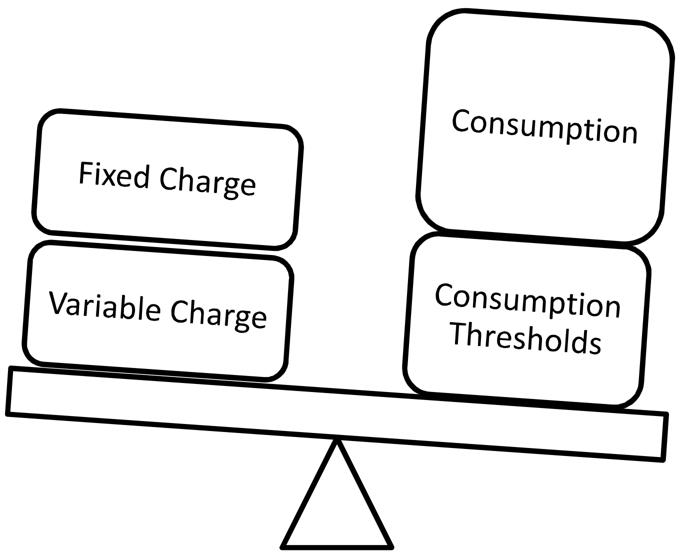
FortisBC's Rate Design Principles

- Recovering the cost of service
- Fair appointment of costs among customers
- Price signals to encourage efficient use
- Customer understanding and acceptance
- Practical and cost effective to implement
- Rate stability
- Revenue Stability
- Avoidance of undue discrimination

The weight placed on each of these principles can vary

Balancing Rate Design Options

Revenue Requirement



Changing one element of the rates causes impacts on others so that the total revenue requirement is still recovered.

Current Residential Rate Structures

RS01 - Residential Conservation Rate

RS03 – Exempt Flat Rate (Farm Use)

Time-of-Use (TOU) – Closed to new customers

RD6
SC5

Slide 26

RD6 I think a picture of a meter or a house with a meter would be better here. This truck doesn't have much to do with residentail rates.
Roy, Diane, 16/06/2017

SC5 Voila!
Sinclair, Corey, 16/06/2017

Residential Conservation Rate

Directed by the Commission at the end of the 2009 COSA and Rate Design process

Designed to incent conservation

Designed so that only 5% of customers would see a rate increase greater than 10% versus a flat rate

An “Inclining Block” rate structure

- Tier 1 up to 1,600 kWh - $0.10117 per kWh
- Tier 2 above 1,600 kWh - $0.15617 per kWh
- Basic (Customer) Charge

Residential Conservation Rate Results

The Residential Conservation Rate (RCR) has been the subject of a number of reports and public processes since its introduction in 2012.

RCR breakeven bi-monthly consumption is about 2,500 kWh when compared to the flat rate:

- Flat Rate: $37.39 Basic Charge and 0.11749 per kWh

About 78% of customers pay same or less with the RCR

Residential Conservation Rate Options

- There are 4 parts to the RCR – Threshold, Customer Charge, Tier 1 and Tier 2 Rates
- Changing one changes at least one other and will impact customers differently
  - ➢Raise / lower Threshold
  - ➢Raise / lower Customer Charge
  - ➢Change Rate Differential between Tier 1 and Tier 2 Rates by changes one or both of those rates
- Apply Bill Impact test to review results

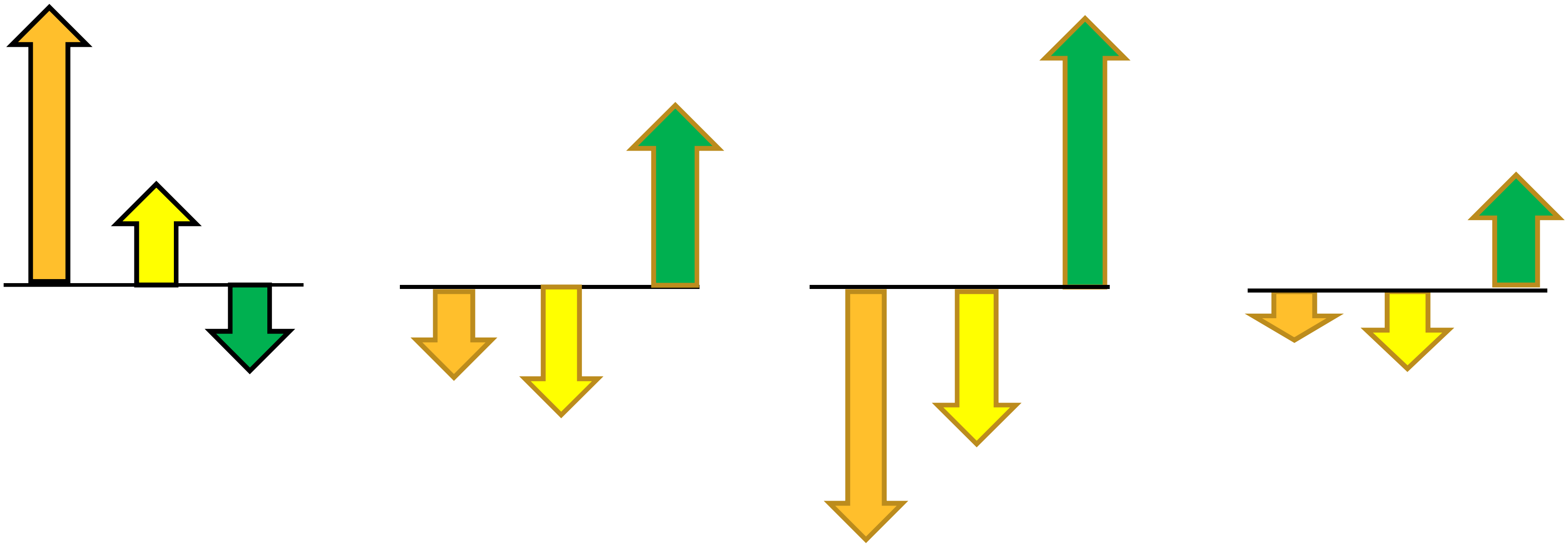
Residential Conservation Rate Examples

Threshold:	***Higher***
Tier 1 Rate:	***-***
Tier 2 Rate	***Higher***
Basic Charge:	***-***

Threshold:	***Higher***
Tier 1 Rate:	***Higher***
Tier 2 Rate:	***-***
Basic Charge:	***-***

Threshold:	***-***
Tier 1 Rate:	***-***
Tier 2 Rate	***Lower***
Basic Charge:	***Higher***

Threshold:	***-***
Tier 1 Rate:	***Lower***
Tier 2 Rate:	***-***
Basic Charge:	***Higher***



Effect on total annual bill

High Consumption Customers

Medium Consumption Customers

Low Consumption Customers

Current Commercial Rate Structures

Small Commercial (Below 45 kVA):

- Flat Rate for usage and Basic Charge

Commercial (Above 45 kVA)

- Declining Block for usage, Basic Charge and Demand Charge

Optional TOU Rates for both classes of Commercial Customers

Slide 31

RD7 this picture doesn't fit. A picture of a small business woulb be better.
Roy, Diane, 16/06/2017

SC6 Done
Sinclair, Corey, 16/06/2017

RD8 Is this a TOU option for both classes? If so can we add say Optional at the front?
Roy, Diane, 16/06/2017

SC7 Done
Sinclair, Corey, 16/06/2017

Rate Design Options for Consideration

- Flat volumetric rate
- Inclining block rate changes
- Time-of-Use rates
- Basic charge adjustments
- Others?

Summary and Next Steps

Next Steps

Next Open House

- Follow up from this Session
- Provide preliminary results
- July 2017

Gather Additional Feedback

RD9

- Meetings
- Surveys
- Website
- July to September 2017

Develop and File Application

- Final Application to be filed by end of 2017
- BCUC will set regulatory process to review the Application

Slide 34

RD9 Please list here the other ways we are gathering feedback
Roy, Diane, 16/06/2017

Provide Your Feedback

Sign-in sheets

Surveys

Website

Hand-out

E-mail: electricratedesign@fortisbc.com

We encourage and welcome your ongoing participation!

For further information, please contact:

electricratedesign@fortisbc.com

Find FortisBC at:

Fortisbc.com

604-576-7000

FORTIS BC™

Energy at work

House Keeping Items

- BCUC Information
- Safety: muster point in case of an evacuation
- First aid attendant
- Washrooms
- Food and Drink
- Sign In Sheet
- Rules of Decorum
- Cellular phones

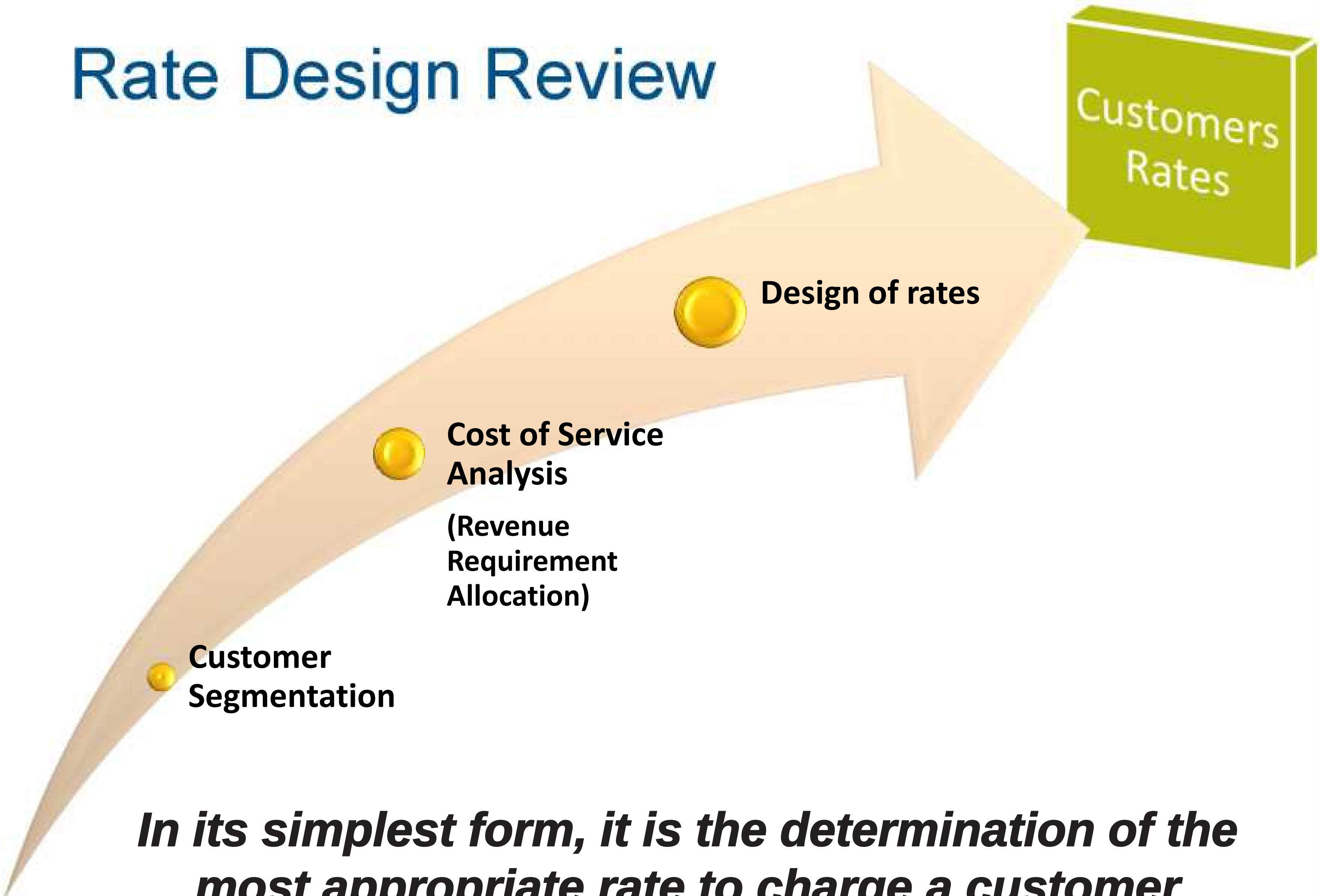
FortisBC Public Consultation

Electricity Rate Design
Open House #2

Matt Mason, *Community & Aboriginal Relations Manager*
Corey Sinclair, *Manager, Regulatory Affairs*

July 2017

Rate Design Review



In its simplest form, it is the determination of the most appropriate rate to charge a customer group that recovers the costs of serving them

COSA Results

Customer Class	Revenue : Cost Ratio (%)*
Residential	98.8
Residential Net Metering	94.3
Small Commercial	102.5
Commercial	104.4
Large Commercial – Primary	102.7
Large Commercial Transmission	111.0
Wholesale (Primary)	95.6
Wholesale (Transmission)	102.3
Street Lighting	92.9
Irrigation	97.7

*as at July 25, 2017 – Subject to further revision

Recovering the Cost of Service
Setting Rates

Total revenue from billing components must equal Residential Cost of service

Next Step

Rate Design Options

Setting Rates – The Math

We can estimate how much revenue we will get from any rate using:

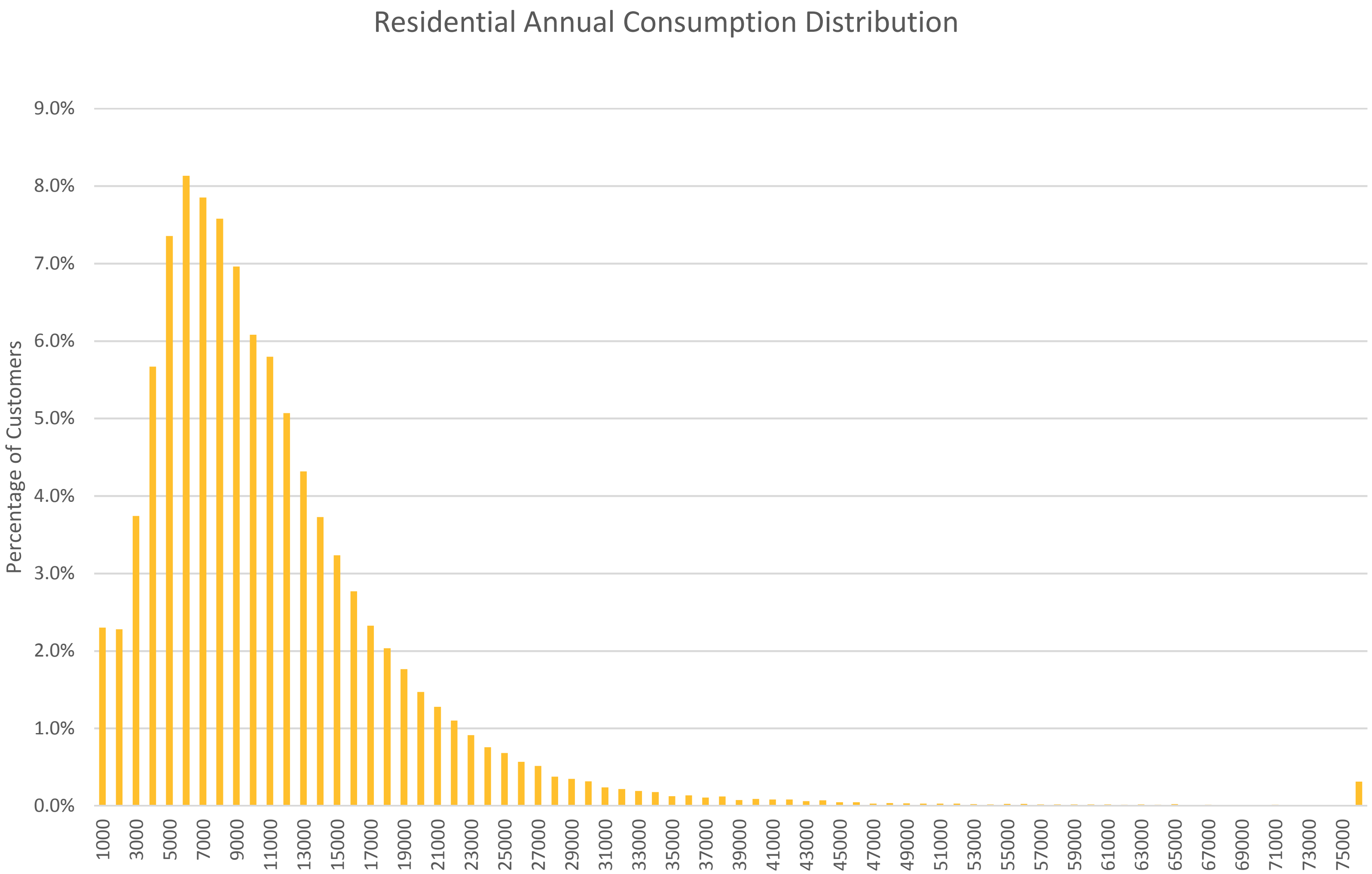
- The number of customers (number of bills)
- The total consumption
    - For the RCR, the % of consumption in each tier
- Cost of Service (Revenue Requirement)

(Consumption x rate(s)) + (#Bills x Basic Charge) = Revenue Requirement

Rates affect customers in different ways depending on consumption

Residential Rates – Guiding Principles

- 95% of customers should have bill increases no greater than 10% as compared to existing rates;
- Recovery of Cost of Service (neutral to current rates)
- Cost-based
- Easy to understand and administer
- Address customer concerns
- Promote conservation


Residential Annual Consumption Distribution
Percentage of Customers
9.0%
8.0%
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
1000
3000
5000
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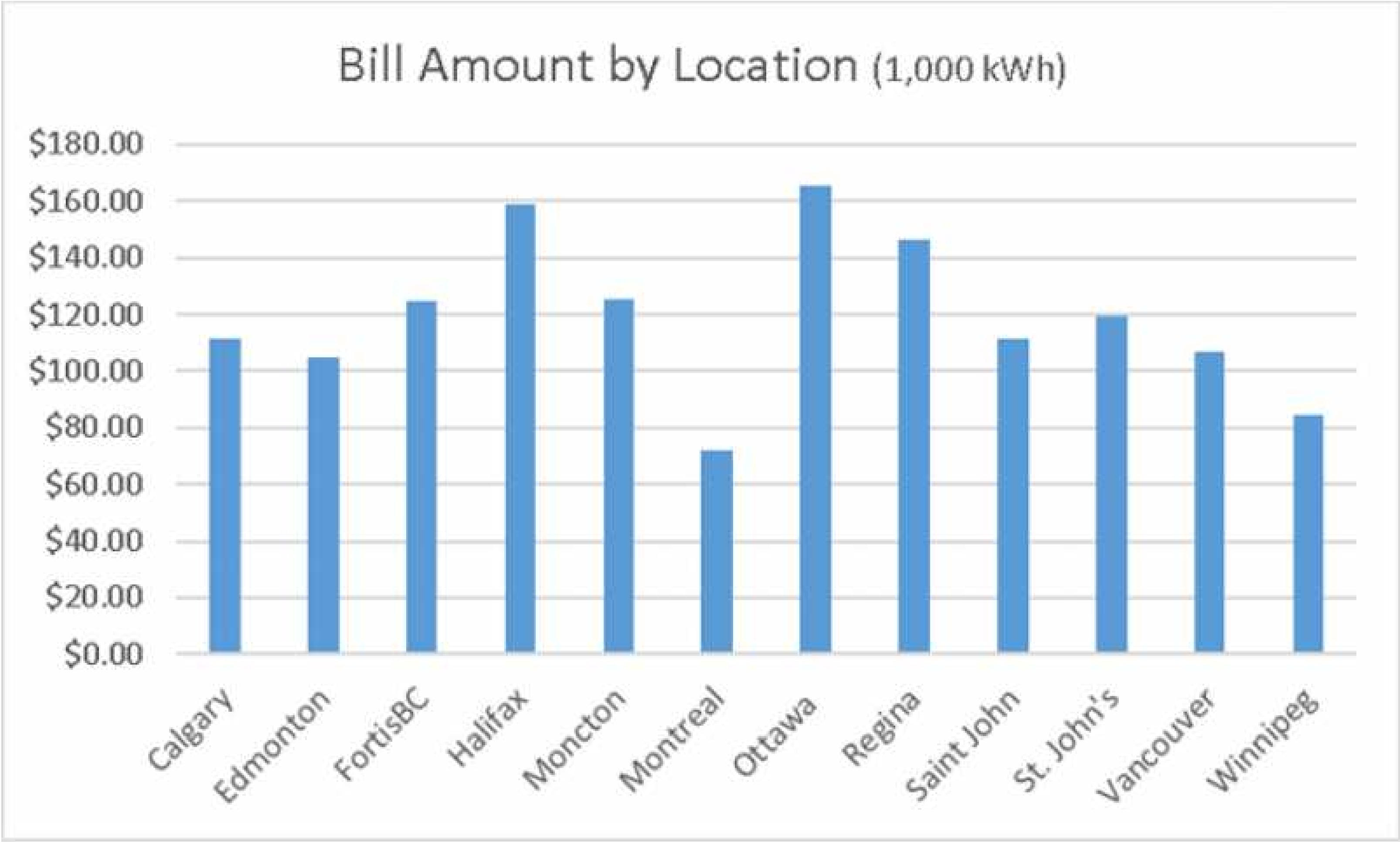

https://www.hydro.mb.ca/regulatory_affairs/energy_rates/electricity/utility_rate_comp.shtml#analysis

Residential Rate Options – What we heard

- No-natural gas access rate
- Return to Flat Rate
- Changing up the RCR
  - Higher Tier 2 threshold
  - Decrease difference between Tier 1 and Tier 2 Rates
  - Declining block rate
  - Seasonal Threshold
  - Change Customer Charge
- Optional Time-of-Use

Rate:	Separate Rate for Customers without Access to Natural Gas

- No cost basis that is isolated strictly to “access” to natural gas.
  - Load characteristics similar to other electric heat customers and high consumption customers;
  - Raises fairness issues
- Administratively cumbersome;
- Challenging for Approval;
- Other options for choice are available.
- We can deal with high-consumption issues through alternate general rate design.

Rate:	RCR Changes

Modelled:

- Increase Threshold
- Increased Threshold, Basic Charge & Compressed Rates
- Compressed Rates only
- Increased Basic Charge & Compressed Rates
- Declining Block Rate

Not Modelled:

- Seasonal Threshold / Rate

Rate:	Flat Default Residential Rate

- Cost Based;
- Same for all customers;
- Easy to understand and administer;
- Limited conservation incentive;
- Unacceptable bill Impacts

1. Current RCR vs Existing Flat Rate

Basic Charge: $18.70 per month
Energy rate: 11.749 cents/kWh

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%	

Current Rate: Basic Charge:$16.05, Tier 1: $0.10117/kWh, Tier 2: $0.15617/kWh, Threshold: 800 kWh/month

2. Current RCR vs Modified Flat Rate

Basic Charge: $20.00 per month
Energy rate: 11.58 cents/kWh

Annual Consumption	Percent of Total Customers	Average Annual Current Bill	Average Bill Difference (%)	Average Annual Bill Difference ($)
Above 35,000	2%	$ 8,849	-19%	-1,698
30,000 - 35,000	1%	$ 4,697	-15%	-726
25,000 - 30,000	2%	$ 3,911	-13%	-523
20,000 - 25,000	5%	$ 3,131	-10%	-322
15,000 - 20,000	10%	$ 2,359	-5%	-126
10,000 - 15,000	22%	$ 1,602	4%	58
5,000 to 10,000	37%	$ 961	14%	135
0 to 5,000	21%	$ 511	19%	95
Percent of Customer with Annual Bill Increase			75%	
Percent of Customers with Impact Below 10%			45%	

Current Rate: Basic Charge:$16.05, Tier 1: $0.10117/kWh, Tier 2: $0.15617/kWh, Threshold: 800 kWh/month

3. Current RCR vs Higher Threshold and Compressed Rates

Basic Charge:	$16.05 per month	Tier 1 Rate:	10.7 cents/kWh
Threshold:	1,000 kWh	Tier 2 Rate:	15.617 cents/kWh

Annual Consumption	Percent of Total Customers	Average Annual Current Bill	Average Bill Difference (%)	Average Annual Bill Difference ($)
Above 35,000	2%	$ 8,849	-1%	-74
30,000 - 35,000	1%	$ 4,697	-1%	-60
25,000 - 30,000	2%	$ 3,911	-1%	-59
20,000 - 25,000	5%	$ 3,131	-2%	-55
15,000 - 20,000	10%	$ 2,359	-2%	-46
10,000 - 15,000	22%	$ 1,602	-1%	-14
5,000 to 10,000	37%	$ 961	3%	29
0 to 5,000	21%	$ 511	3%	17
Percent of Customer with Annual Bill Increase			61%	
Percent of Customers with Impact Below 10%			100%	

Current Rate: Basic Charge:$16.05, Tier 1: $0.10117/kWh, Tier 2: $0.15617/kWh, Threshold: 800 kWh/month

4. Current RCR vs Higher Threshold, Basic Charge & Compressed Rates

Basic Charge:	$18.00 per month	Tier 1 Rate:	10.77 cents/kWh
Threshold:	1,000 kWh	Tier 2 Rate:	14.6 cents/kWh

Annual Consumption	Percent of Total Customers	Average Annual Current Bill	Average Bill Difference (%)	Average Annual Bill Difference ($)
Above 35,000	2%	$ 8,849	-6%	-491
30,000 - 35,000	1%	$ 4,697	-5%	-234
25,000 - 30,000	2%	$ 3,911	-5%	-182
20,000 - 25,000	5%	$ 3,131	-4%	-128
15,000 - 20,000	10%	$ 2,359	-3%	-72
10,000 - 15,000	22%	$ 1,602	0%	0
5,000 to 10,000	37%	$ 961	6%	57
0 to 5,000	21%	$ 511	9%	45
Percent of Customer with Annual Bill Increase			68%	
Percent of Customers with Impact Below 10%			97%	

Current Rate: Basic Charge:$16.05, Tier 1: $0.10117/kWh, Tier 2: $0.15617/kWh, Threshold: 800 kWh/month

5. Current RCR vs Compressed Rate

Basic Charge:	$16.05per month	Tier 1 Rate:	10.75 cents/kWh
Threshold:	800 kWh	Tier 2 Rate:	14.42 cents/kWh

Annual Consumption	Percent of Total Customers	Average Annual Current Bill	Average Bill Difference (%)	Average Annual Bill Difference ($)
Above 35,000	2%	$ 8,849	-6%	-497
30,000 - 35,000	1%	$ 4,697	-4%	-210
25,000 - 30,000	2%	$ 3,911	-4%	-150
20,000 - 25,000	5%	$ 3,131	-3%	-91
15,000 - 20,000	10%	$ 2,359	-1%	-33
10,000 - 15,000	22%	$ 1,602	1%	21
5,000 to 10,000	37%	$ 961	4%	39
0 to 5,000	21%	$ 511	4%	18
Percent of Customer with Annual Bill Increase			76%	
Percent of Customers with Impact Below 10%			100%	

Current Rate: Basic Charge:$16.05, Tier 1: $0.10117/kWh, Tier 2: $0.15617/kWh, Threshold: 800 kWh/month

6. Current RCR vs Higher Basic Charge & Compressed Rate

Basic Charge:	$18.00 per month	Tier 1 Rate:	10.22 cents/kWh
Threshold:	800 kWh	Tier 2 Rate:	14.80 cents/kWh

Annual Consumption	Percent of Total Customers	Average Annual Current Bill	Average Bill Difference (%)	Average Annual Bill Difference ($)
Above 35,000	2%	$ 8,849	-4%	-349
30,000 - 35,000	1%	$ 4,697	-3%	-151
25,000 - 30,000	2%	$ 3,911	-3%	-110
20,000 - 25,000	5%	$ 3,131	-2%	-70
15,000 - 20,000	10%	$ 2,359	-1%	-30
10,000 - 15,000	22%	$ 1,602	1%	8
5,000 to 10,000	37%	$ 961	3%	28
0 to 5,000	21%	$ 511	6%	29
Percent of Customer with Annual Bill Increase			73%	
Percent of Customers with Impact Below 10%			99%	

Current Rate: Basic Charge:$16.05, Tier 1: $0.10117/kWh, Tier 2: $0.15617/kWh, Threshold: 800 kWh/month

7. Current RCR vs Higher Basic Charge & Compressed Rate

Basic Charge:	$17.00 per month	Tier 1 Rate:	10.85 cents/kWh
Threshold:	800 kWh	Tier 2 Rate:	13.90 cents/kWh

Annual Consumption	Percent of Total Customers	Average Annual Current Bill	Average Bill Difference (%)	Average Annual Bill Difference ($)
Above 35,000	2%	$ 8,849	-8%	-720
30,000 - 35,000	1%	$ 4,697	-7%	-307
25,000 - 30,000	2%	$ 3,911	-6%	-221
20,000 - 25,000	5%	$ 3,131	-4%	-135
15,000 - 20,000	10%	$ 2,359	-2%	-52
10,000 - 15,000	22%	$ 1,602	2%	26
5,000 to 10,000	37%	$ 961	6%	56
0 to 5,000	21%	$ 511	7%	34
Percent of Customer with Annual Bill Increase			75%	
Percent of Customers with Impact Below 10%			100%	

Current Rate: Basic Charge:$16.05, Tier 1: $0.10117/kWh, Tier 2: $0.15617/kWh, Threshold: 800 kWh/month

8. Current RCR vs Higher Basic Charge & Compressed Rate

Basic Charge:	$18.25 per month	Tier 1 Rate:	10.80 cents/kWh
Threshold:	800 kWh	Tier 2 Rate:	13.60 cents/kWh

Annual Consumption	Percent of Total Customers	Average Annual Current Bill	Average Bill Difference (%)	Average Annual Bill Difference ($)
Above 35,000	2%	$ 8,849	-10%	-850
30,000 - 35,000	1%	$ 4,697	-8%	-364
25,000 - 30,000	2%	$ 3,911	-7%	-263
20,000 - 25,000	5%	$ 3,131	-5%	-163
15,000 - 20,000	10%	$ 2,359	-3%	-65
10,000 - 15,000	22%	$ 1,602	2%	28
5,000 to 10,000	37%	$ 961	7%	67
0 to 5,000	21%	$ 511	10%	49
Percent of Customer with Annual Bill Increase			75%	
Percent of Customers with Impact Below 10%			95%	

Current Rate: Basic Charge:$16.05, Tier 1: $0.10117/kWh, Tier 2: $0.15617/kWh, Threshold: 800 kWh/month

9. Current RCR vs Declining Block Rate

Basic Charge:	$17.00 per month	Tier 1 Rate:	12.85 cents/kWh
Threshold:	800 kWh	Tier 2 Rate:	10.15 cents/kWh

Annual Consumption	Percent of Total Customers	Average Annual Current Bill	Average Bill Difference (%)	Average Annual Bill Difference ($)
Above 35,000	2%	$ 8,849	-26%	-2,276
30,000 - 35,000	1%	$ 4,697	-21%	-964
25,000 - 30,000	2%	$ 3,911	-18%	-690
20,000 - 25,000	5%	$ 3,131	-13%	-418
15,000 - 20,000	10%	$ 2,359	-6%	-152
10,000 - 15,000	22%	$ 1,602	6%	94
5,000 to 10,000	37%	$ 961	19%	181
0 to 5,000	21%	$ 511	18%	92
Percent of Customer with Annual Bill Increase			76%	
Percent of Customers with Impact Below 10%			40%	

Current Rate: Basic Charge:$16.05, Tier 1: $0.10117/kWh, Tier 2: $0.15617/kWh, Threshold: 800 kWh/month

Summary

		Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8	Option 9
Basic Charge		$ 18.70	$ 20.00	$ 16.05	$ 18.00	$ 16.05	$ 18.00	$ 17.00	$ 18.25	$ 17.00
Tier 1 Rate		$ 0.11749	$ 0.11580	$ 0.10700	$ 0.10770	$ 0.10750	$ 0.10220	$ 0.10850	$ 0.10800	$ 0.12850
Tier 2 Rate		n/a	n/a	$ 0.15617	$ 0.14600	$ 0.14420	$ 0.14800	$ 0.13900	$ 0.13600	$ 0.10150
Threshold		n/a	n/a	1,000	1,000	800	800	800	800	800
Annual Consumption	Percent of Total Customers	**Average Percentage Bill Difference**								
Above 35,000	2%	-20%	-19%	-1%	-6%	-6%	-4%	-8%	-10%	-26%
30,000 - 35,000	1%	-16%	-15%	-1%	-5%	-4%	-3%	-7%	-8%	-21%
25,000 - 30,000	2%	-13%	-13%	-1%	-5%	-4%	-3%	-6%	-7%	-18%
20,000 - 25,000	5%	-10%	-10%	-2%	-4%	-3%	-2%	-4%	-5%	-13%
15,000 - 20,000	10%	-5%	-5%	-2%	-3%	-1%	-1%	-2%	-3%	-6%
10,000 - 15,000	22%	4%	4%	-1%	0%	1%	1%	2%	2%	6%
5,000 to 10,000	37%	13%	14%	3%	6%	4%	3%	6%	7%	19%
0 to 5,000	21%	15%	19%	3%	9%	4%	6%	7%	10%	18%
Percent >10%		53%	53%	0%	2%	0%	1%	0%	4%	59%

Rate:	Optional Time of Use (TOU)

Objective:
- Shift consumption away from times of high system load
- Provide an alternative to the RCR

Notes:
- Revenue neutral to the current RCR on a Customer Class basis
- No demonstrable cost basis for TOU at this time

Structure:
- 3 Seasons based on COSA & load profiles
- 3 Time Periods based on COSA & load profiles

Rate:	Optional Time of Use (TOU)

	Winter	Summer	Shoulder
	December, January	July, August	Other Months
On-Peak	7:00 am – 12:00 pm 4:00 pm – 9:00 pm	12:00 pm – 9:00 pm	
Mid-Peak	12:00 pm – 4:00 pm	7:00 am – 12:00 pm	7:00 am – 9:00 pm
Off-Peak	9:00 pm – 7:00 am	9:00 pm – 7:00 am	9:00 pm – 7:00 am

Rate	Price ($/kWh)
On-Peak	0.1700
Mid-Peak	0.1100
Off-Peak	0.0950

Rate:	Optional Time of Use (TOU) - Example

Total Monthly Consumption:	**2,000 kWh**

Residential Conservation Rate Billing		
Tier 1 Charges	800 kWh x 0.10117	$81
Tier 2 Charges	1,200 kWh x 0.15617	$187
Total Energy Charges		$268

Time-of-Use Billing			
On-Peak Charges	22%	440 kWh x 0.17	$75
Mid-Peak Charges	37%	740 kWh x 0.11	$81
Off-Peak Charges	41%	820 kWh x 0.095	$78
Total Energy Charges			$234

Rate:	Optional Time of Use (TOU) - Alternative

Weekends all off-peak

Time-of-Use Billing		
Rates *		Weekends off-peak
On-Peak Charges	$0.17	$0.22
Mid-Peak Charges	$0.11	$0.12
Off-Peak Charges	$0.095	$0.095

*** Preliminary Rates**

Summary and Next Steps

Provide Your Feedback

Sign-in sheets

Surveys

Website

Hand-out

E-mail: electricratedesign@fortisbc.com

We encourage and welcome your ongoing participation!

For further information, please contact:

electricratedesign@fortisbc.com

Find FortisBC at:

Fortisbc.com

604-576-7000

2017 Rate Design Application
FortisBC Inc. (FBC)

Cost of Service Information Session

Corey Sinclair – Manager, Regulatory Affairs, FBC
Sarah Wagner – Senior Regulatory Analyst, FBC
Gail Tabone – Senior Associate, EES Consulting

October 25, 2017

FORTIS BC™

Workshop Purpose – COSA Specific

To provide context and information in support of the 2017 FBC Rate Design Application

Review the current rates and services offered by FBC

Electric Cost of Service (COSA) Approach and Methodology Review

Initial COSA Results and Impact on Rates

Gather feedback and answer questions

Agenda

Introduction & Agenda	*Corey Sinclair*
Part I - Scope of 2017 COSA and RDA • Introduction • Rate Setting Principles • FBC Customer and Load Summary	*Corey Sinclair*
Part II - COSA Approach and Methodology • Cost of Service Methods • Supporting Analysis • Time of Use Cost Differentials	*Gail Tabone*
Part III - Standard Charges / Terms and Conditions	*Sarah Wagner*
Part IV - COSA Results • Revenue to Cost Ratios • Rebalancing • Next Steps	*Corey Sinclair*
Open Question Period	*All*

Application Scope

The 2017 Rate Design Application Addresses:

- All Default Bundled Service Rates
- Proposals for Optional Rate Offerings
- Point to Point Transmission Services
- Terms and Conditions
- Standard Charges and Extensions
- Potential Rate Rebalancing

FBCs Rate Design Principles

- Recovering the cost of service
- Fair appointment of costs among customers
- Price signals to encourage efficient use
- Customer understanding and acceptance
- Practical and cost effective to implement
- Rate stability
- Revenue Stability
- Avoidance of undue discrimination

The weight placed on each of these principles is not always equal

Tariff Rate Schedules and Services Overview

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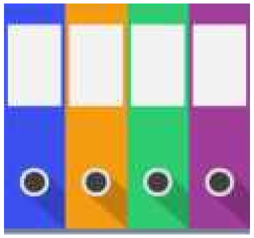
FBC Tariff Rate Schedules and Services

Overview



- **A Tariff is a BCUC approved rate schedule of rates that can be charged by a utility to its customers**
  - Includes bundled retail rate schedules, in addition to other specific rate schedules that offer other services
  - Includes the Standard Fees and Charges Schedule, which includes fees and charges such as:
    - *Application Fees*
    - *Extension Policies*

The FBC General Terms and Conditions (GT&Cs) of Service

- Outline the terms and conditions under which FBC operates

Default Rate Schedules

Rate Schedule 1	• Residential Service • *2016 Average Number of Customers – 116,741*
Rate Schedule 20	• Small Commercial Service (<40 kW) • *2016 Average Number of Customers – 13,500*
Rate Schedule 21	• Commercial Service (40 kW > 500 kW) • *2016 Average Number of Customers – 1,510*
Rate Schedule 30	• Large Commercial Service - Primary (>500 kVA) • *2016 Average Number of Customers - 46*
Rate Schedule 31	• Large Commercial Service -Transmission (>5,000 kVA) • *2016 Average Number of Customers - 4*
Rate Schedule 40	• Wholesale Service - Primary • *2016 Average Number of Customers – 5*
Rate Schedule 41	• Wholesale Service - Transmission • *2016 Average Number of Customers – 1*
Rate Schedule 50	• Street lighting • *2016 Average Number of Customers – 1,590*
Rate Schedule 60	• Irrigation • *2016 Forecast Average Number of Customers – 9.038*

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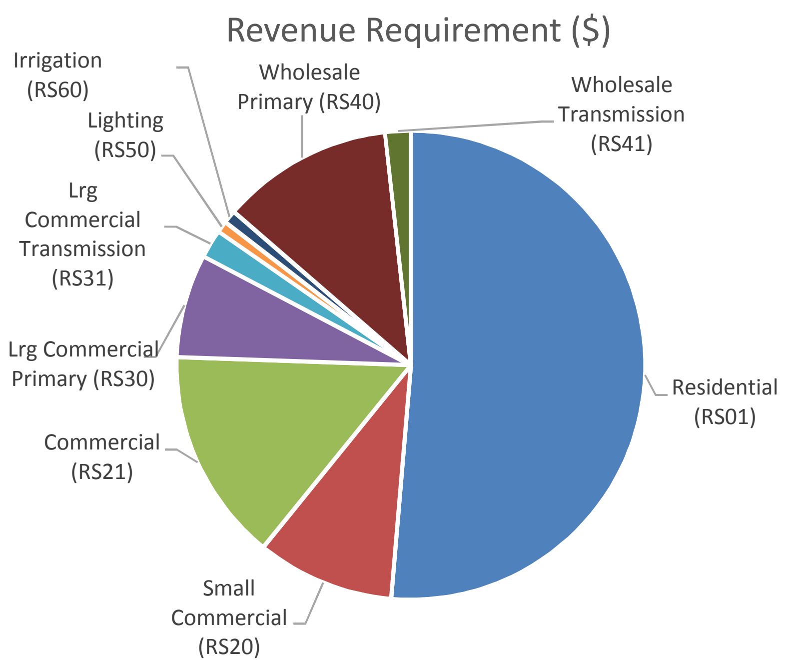
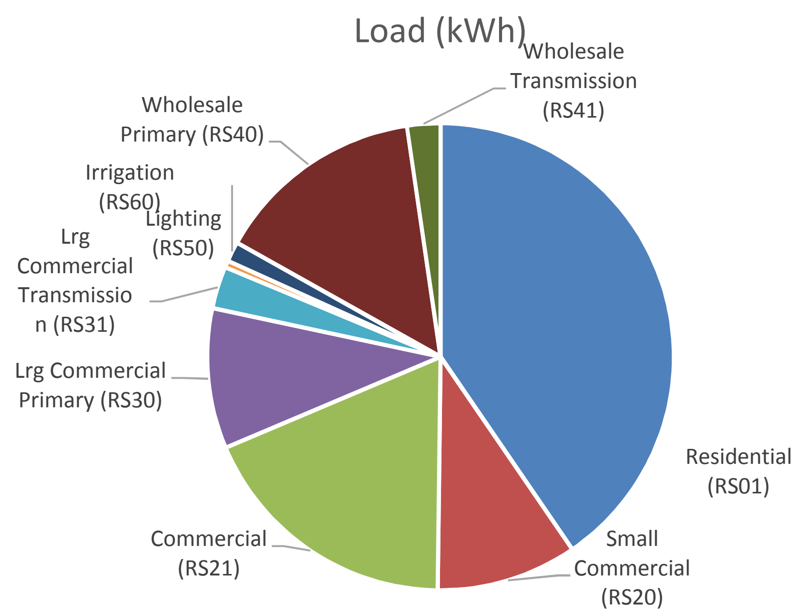
Optional Rate Schedules

Time of Use	• Available for all Customer Classes • ***Residential Closed to new Customers***
Green Rate Rider	• Customer can pay a premium of 1.5 cents/kWh or a specified dollar amount
Net Metering	• For the interconnection of customer-owned generation limited to personal consumption and 50 kW
Stand-by & Maintenance	• Available to RS 31 customers with self-generation
Other	• Transmission and related, • Standard Charges • Extensions • DSM, etc.

Summary of Customer Class Contribution to overall Load and Revenues





Questions

Cost of Service Approach and Methodology

PART II

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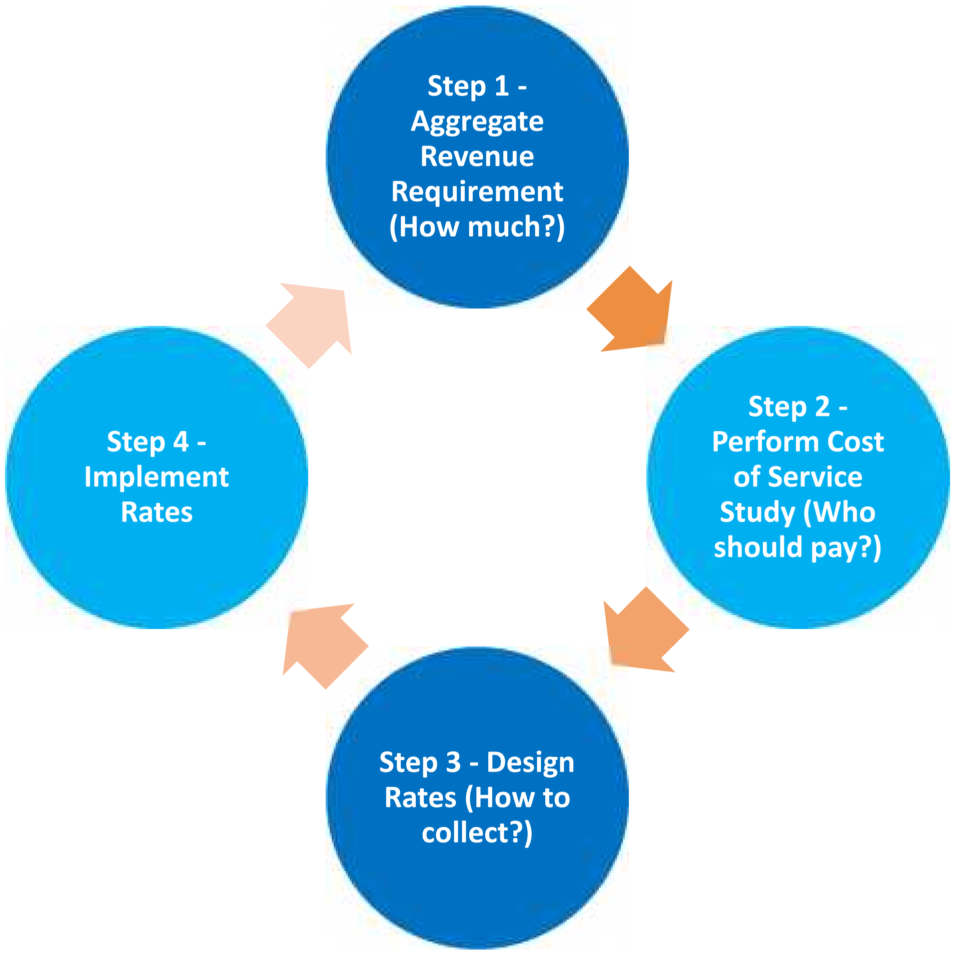
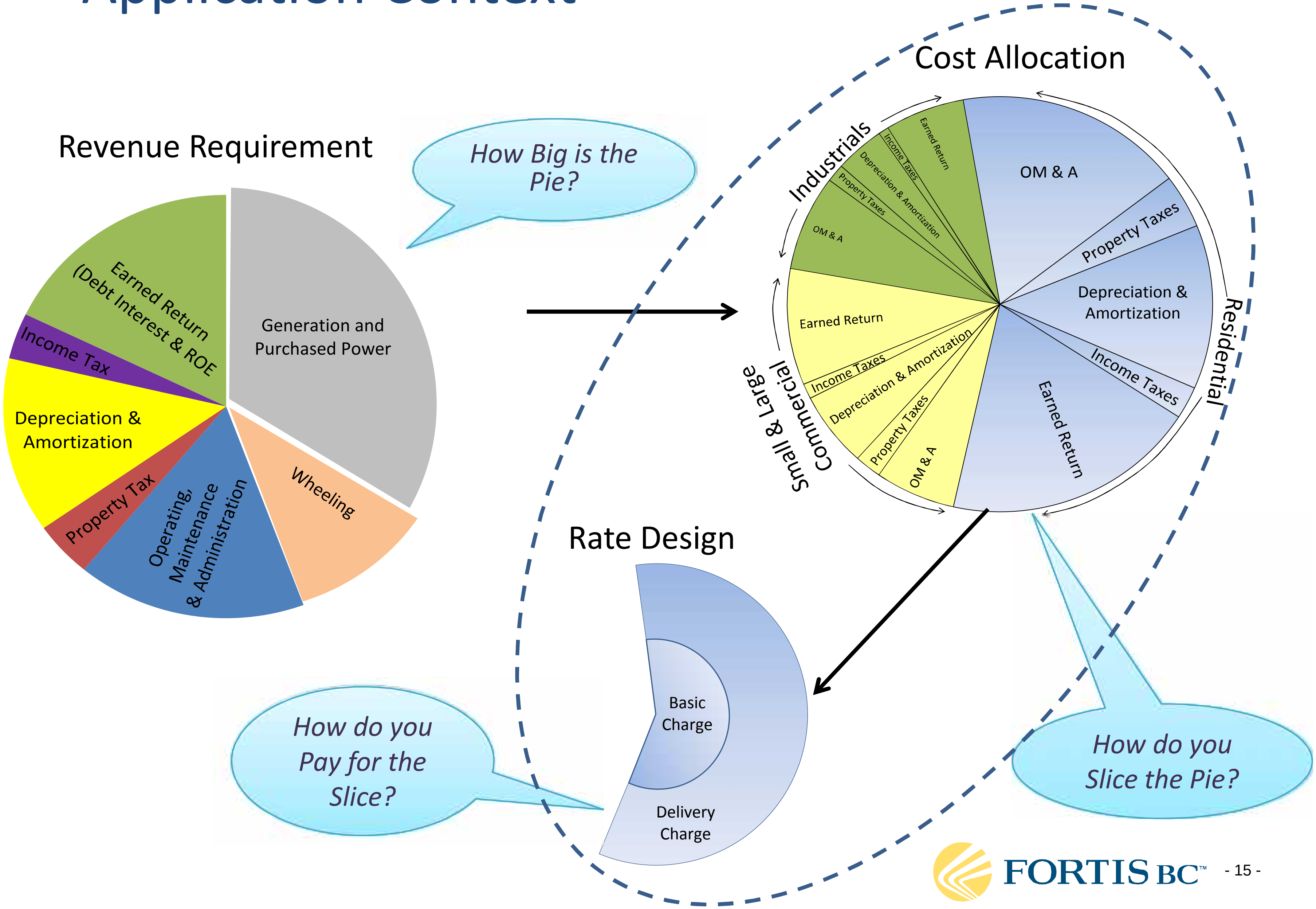
Steps in a Rate Design Process



Application Context



Overview of an Application

- History and Background
- Rate Design Principles
- Cost of Service Approach
- Supporting Studies
- COSA Results and Rebalancing
- Rate Design Proposal by Class
- Summary

Summary of Revenue Requirements

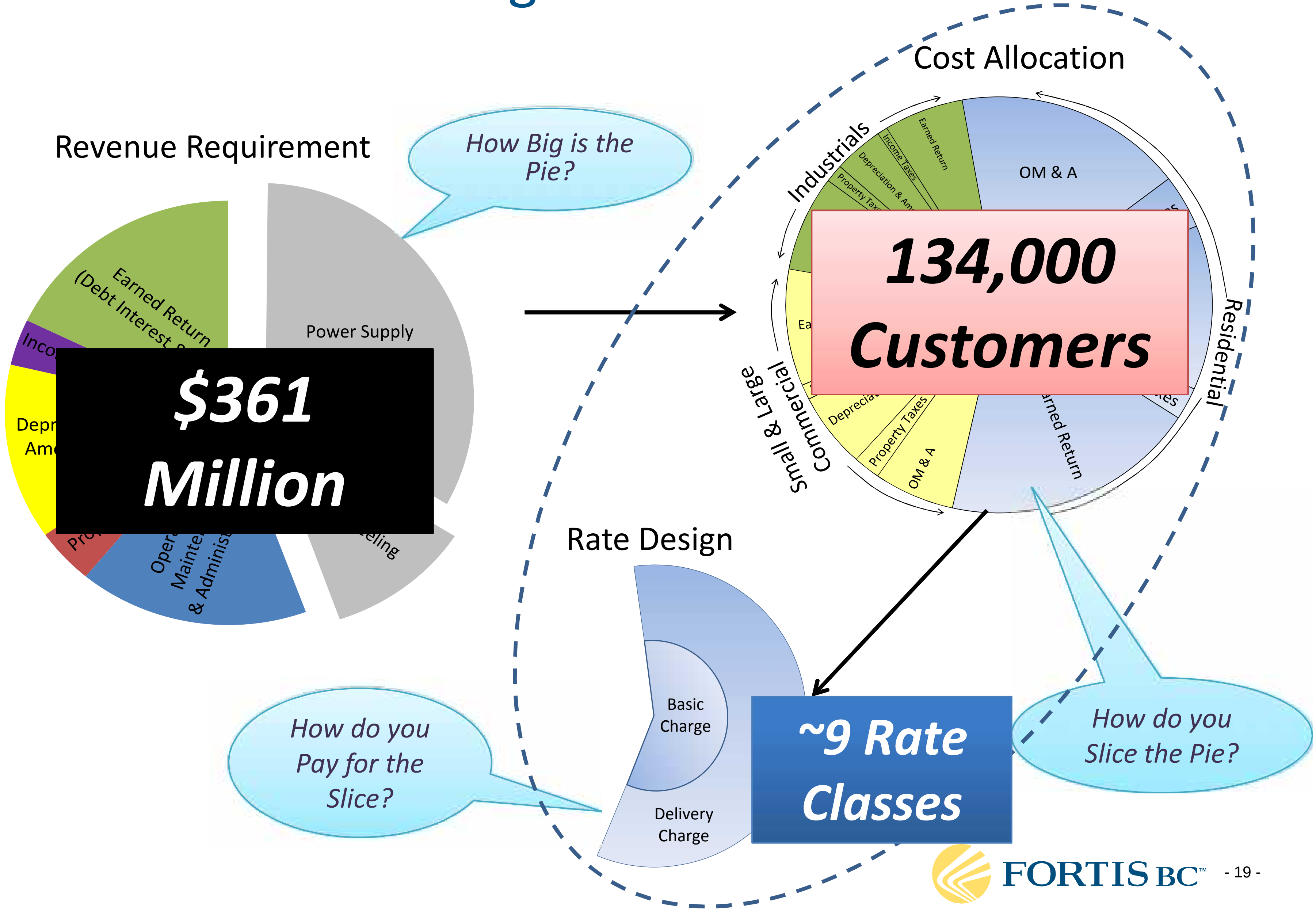
Based on 2017 Evidentiary Update

Cost Category	2017 Forecast (Million)
Production	$152.2
Transmission	$18.3
Distribution	$10.4
Customer Service, Accounts & Sales	$6.5
Administrative & General	$13.0
Depreciation	$55.7
Taxes	$16.1
Return & Income Tax	$98.1
Other Revenues	-$9.5
Net Revenue Requirements	$360.7

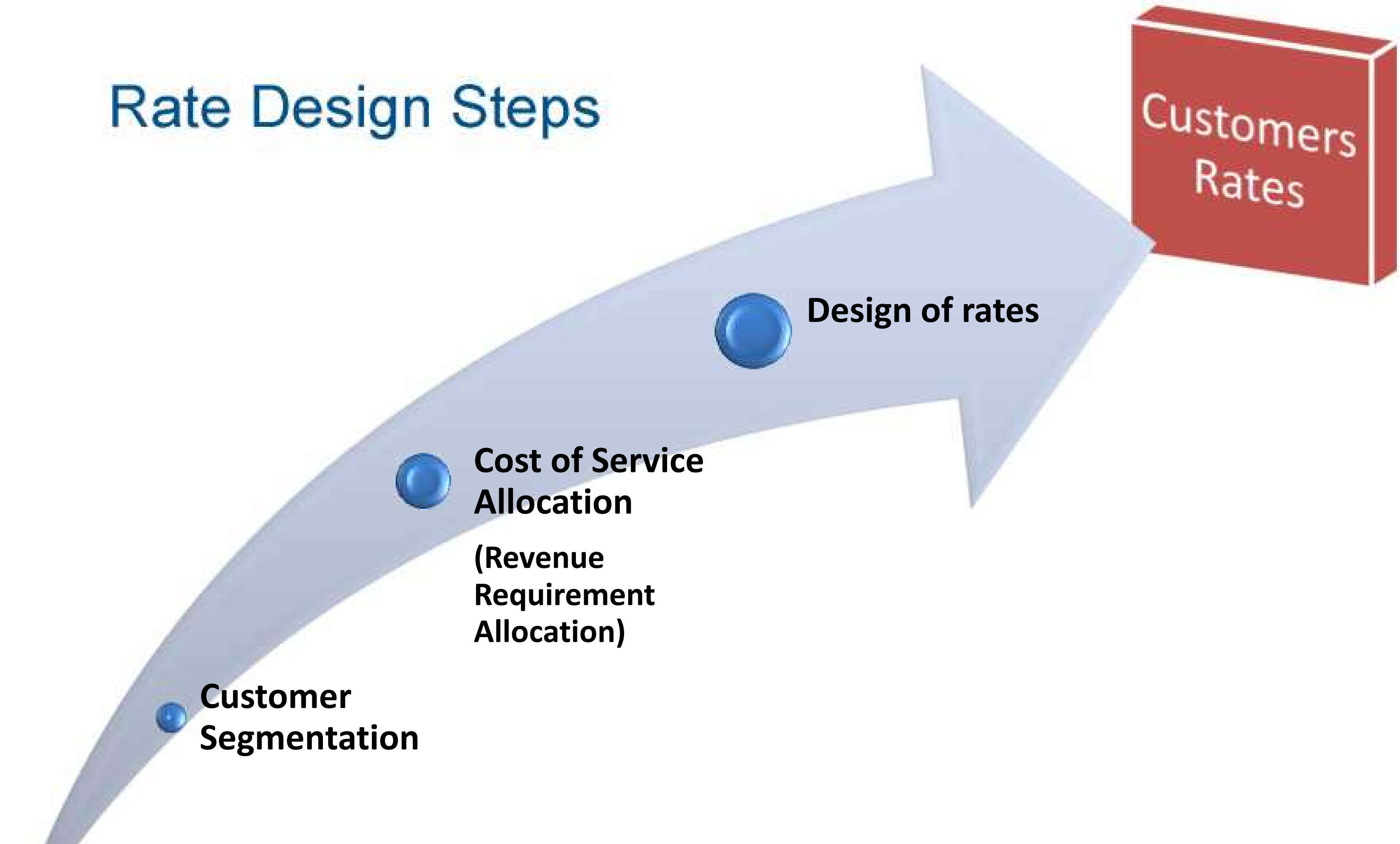
What is a COSA?

- How we split up the Revenue Requirement amongst customers
- Reflects Cost Causation
- Meets Rate Design Principles of fairness and appropriate price signals

COSA and Rate Design Process

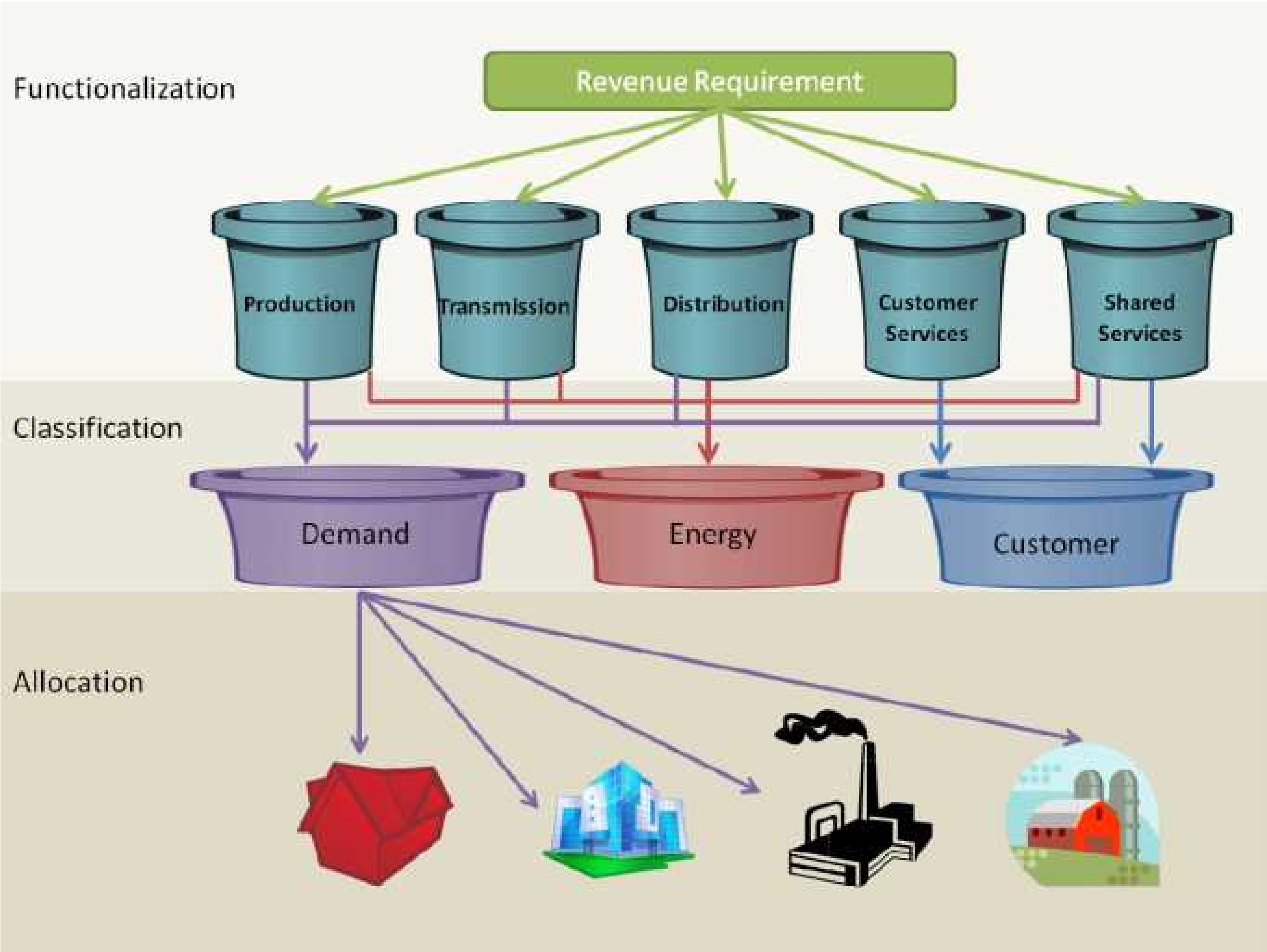


Rate Design Steps



In its simplest form, it is the determination of the most appropriate rate to charge a customer group that recovers the costs of serving them

All Components Affect Rate Design



Cost Causation = How is the System Built?

Meters and Services

- One customer means one service line and meter – but different sizes by class

Distribution

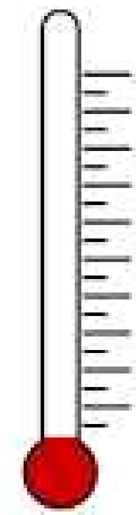
- Poles, wires and transformers are built to meet each customer's highest peak load, whenever it occurs (Non-coincident peak)

Transmission

- Built to transmit generated and purchased power to the distribution system, sized to meet system peak loads (Coincident Peak)

Power Supply

- Combination of generation and power contracts to meet both system peak loads and energy throughout the year (Coincident Peak)



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Functionalization

- System of Accounts generally defines functions
  - Production/Power Supply
  - Transmission
  - Distribution
- Applies to Rate Base and Revenue Requirements
- Shared Categories/Functions Include
  - General Plant (Rate Base)
  - Customer Service, Accounts & Sales
  - Administrative & General
- Types of Costs
  - Operation & Maintenance (O&M)
  - Depreciation
  - Taxes
  - Return
  - Income Tax
  - Other Revenues

Classification

- Splits each rate base/revenue requirement account into demand, energy and/or customer factors
  - Rate Base first
  - Expense items often follows rate base
- Main task within the COSA
- Follows cost causation
  - Standard practice includes several options
  - Unique to the circumstances of the utility
  - Often unique to the jurisdiction and past precedents

Allocation

- Takes costs classified to customer and allocates on the basis of number of customers, same for energy and demand
- Multiple types of allocation factors for each type
  - Customer – standard, weighted for meters/service, weighted for accounting/metering
  - Energy – annual energy
  - Demand – non-coincident (NCP), monthly coincident peak (12 CP), winter/summer coincident peaks (2 CP)

Development of Load Data for Allocation

Energy
- Based on actual monthly sales by class for 2016
- Adjusted for growth to match 2017 approved forecast

NCP
- Based on metered demand for those with demand meters
- Others based on monthly load factors calculated from AMI data

CP
- Based on hourly AMI data by class, highest for class and system peak
- Ratio between NCP and class peak and system peak

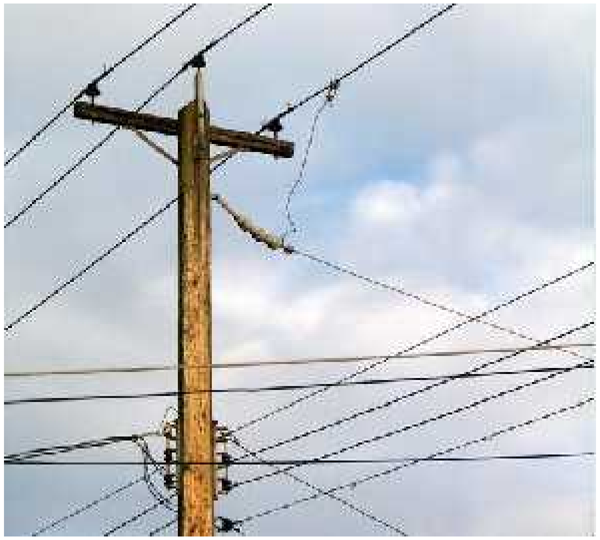
Losses
- Added loss factors differentiated by voltage level
- Adjustments so sum of classes equals system totals

COSA Methodology

Cost Item	Classification Method	Allocator Used
Power Supply	Split 20% demand and 80% energy based on the equivalent of purchasing all power from BC Hydro 3808 tariff	Costs calculated for each month and then allocated on the basis of each month's demand and energy
Transmission	100% Demand	2 CP (average of winter and summer coincident peaks)
Distribution - **Stations**	100% Demand	Non-coincident peak (NCP)
Distribution **- Poles, wires and transformers**	Minimum System Study to split between customers and demand	Actual customers and non-coincident peak (NCP) adjusted for PLCC
Distribution - **Meters & services** - **Customer service, etc**	100% Customer	- Weighted for meters and services - Weighted for accounting and metering
General Plant and A&G	Labour Ratios used to split between production, transmission and distribution	Follows rate base in each function
Stand-by Service	Treated as other revenues, classified same as all rate base	Allocated same as all rate base

COSA Minimum System Study (MSS)

- Looks at all facilities for poles, wires and transformers
- Some portion of facilities are in place just to connect our customers to the system, this is the minimum system
- MSS basically prices all facilities as if it were the minimum size
- The value of the minimum system divided by the actual value of all the facilities is the percentage classified as 'Customer'
- The balance is classified as 'Demand'
- PLCC Adjustment accounts for the fact that the minimum system can carry some amount of load



Poles = 81% Customer

Wires = 65% Customer

Transformers = 69% Customer

PLCC = 1.09 kW

COSA Customer Weighting Factor

- Study differentiates the cost associated with small customers vs. large customers
- Calculated as a ratio to the cost for a residential customer
- Ratio used to scale upwards the average number of customers in a customer group
- Meters & Services based on cost differentials for average cost of new meter/service
- Customer Accounting & Metering based on level of effort associated with call centre, billing, etc.

RS1 = $115/1.0

RS20 = $202/1.0

RS21 = $318/1.0

RS30/31 = $318/202

RS40/41 = $318/160

Cost Differences for Time of Use Rates

- Cost differences not captured in COSA
- Analysis of hourly system data to develop TOU periods
  - On-peak
  - Mid-peak
  - Off-peak
- Power supply drives cost differentials by time period
- Power supply costs split into different categories to develop cost differentials between TOU periods

Standard Charges / Terms & Conditions

PART III

FORTIS BC™

Terms & Conditions

Review and Align with FEI GT&Cs

- Definitions
- Subheadings and formatting for ease of reference
- Security Deposit Policy
  - Addition of a minimum deposit amount of $50
  - 2 highest consecutive months of consumption (previously 3 months estimated)
  - Unclaimed refund time period of 10 years (previously 7 years)
- Landlord / Tenant Policy
  - Addition of option of agreement with Landlord to assume responsibility for Tenant's non-payment where FortisBC directly contracts with Tenant

Updates to Reflect Current Operations

- AMI Project Updates
  - AMI Meter is the standard meter installed
  - Provision for obstruction of radio-frequency technology
- Clean up Criteria for Residential and Commercial Service

Standard Charges

Update to reflect current costs and operations

Align with FEI standard charges and practices

Changes include:

- Relocate from Rate Schedules (Schedules 80-82) to Terms and Conditions
- Meter Test Fee under-recovering
  - Proposing to charge meter connection fee as work is similar
- Remove minimum connection charge for 400 Amp Service
  - Will charge actual costs
- Remove pre-commencement of AMI Project Set-up Fee for Radio-off Meters

Extensions

Update to reflect current costs and operations

Changes include:

- Removal of superseded and closed Schedule 73 - Extensions
- Relocate from Rate Schedules (Schedule 74) to Terms and Conditions
- Updates to FortisBC Contribution amounts to reflect current rate base
- Inclusion of FortisBC pre-approved contractor option to design Extension

FORTIS BC™

Cost of Service Results and Next Steps

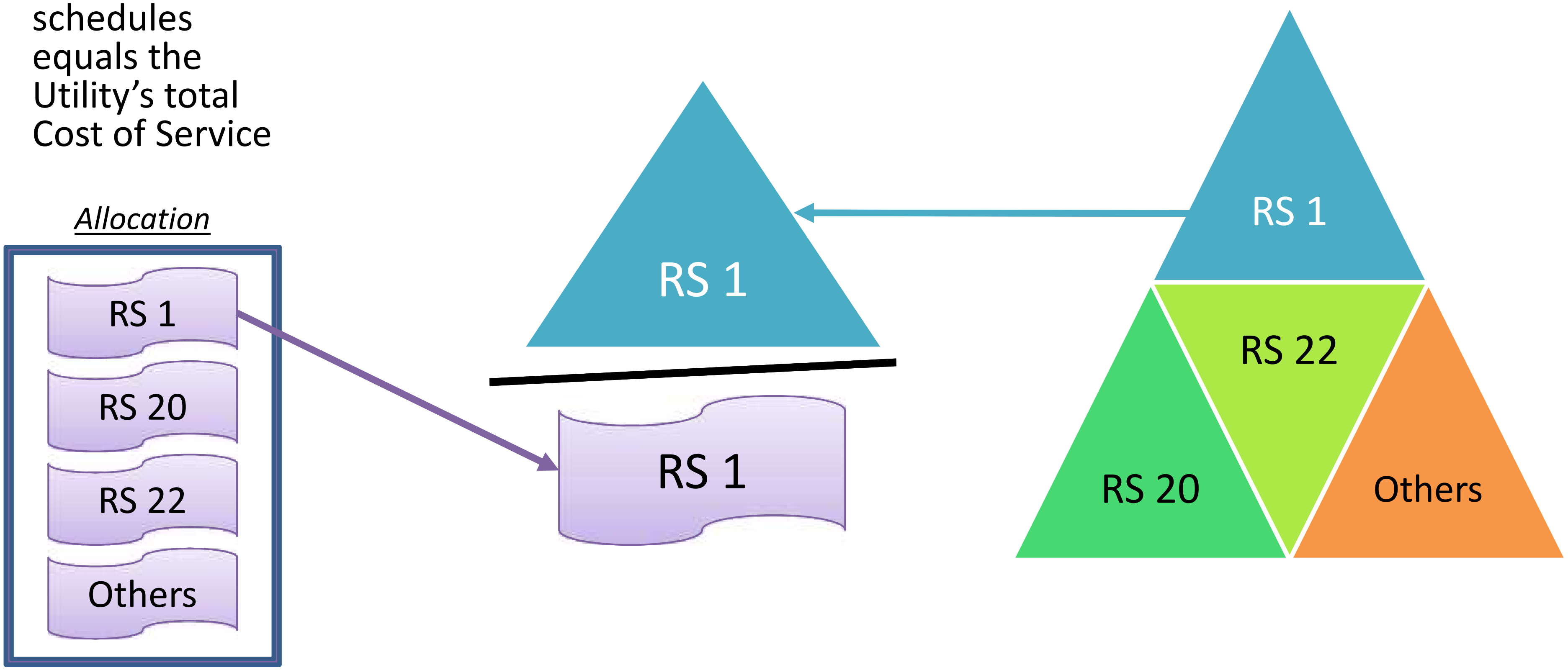
PART IV

FORTIS BC™

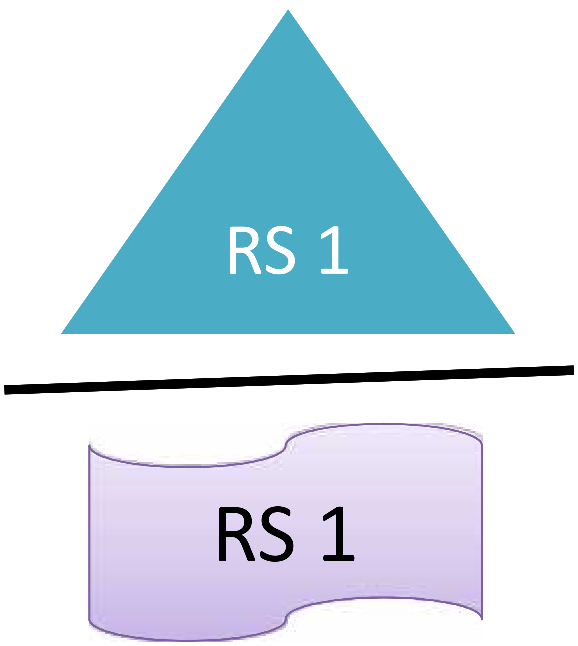
Revenue to Cost Ratio (R/C)

- Sum of all costs allocated to each of the rate schedules equals the Utility's total Cost of Service

- Total revenue collected by rate schedule



Revenue to Cost Ratio



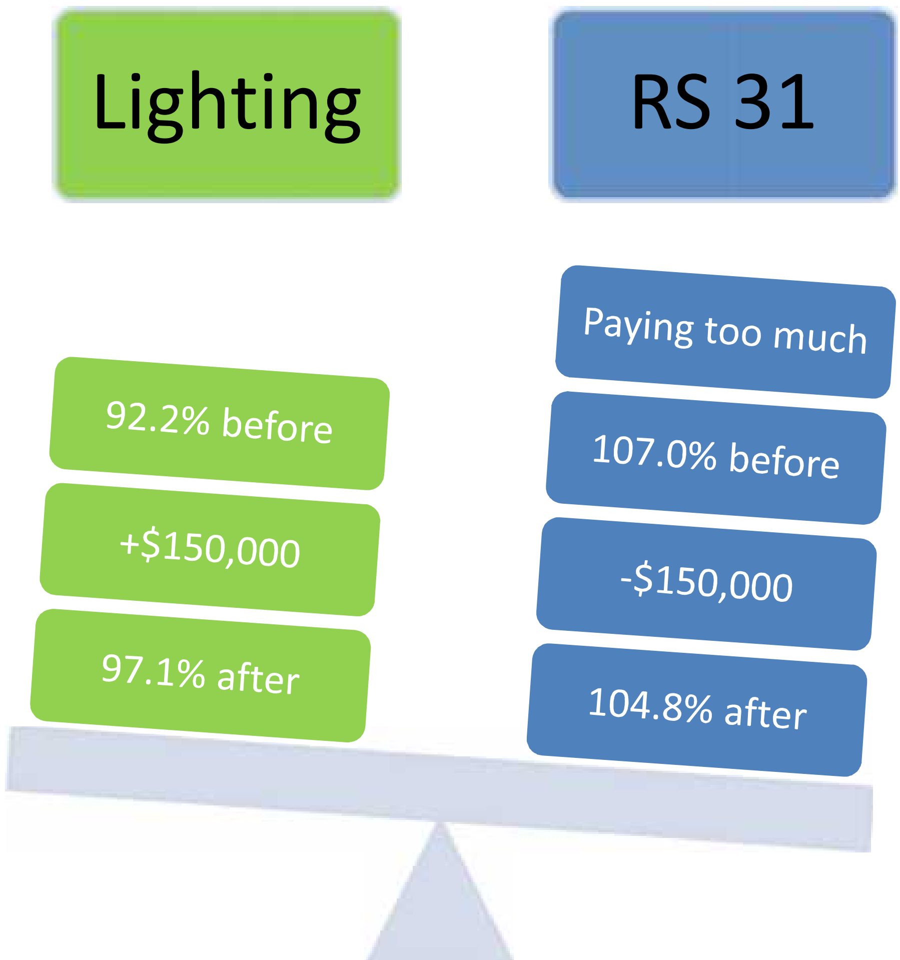
- If a customer group's R/C ratio is within a range around unity, their rates are assumed to be fair and reasonable from a cost allocation perspective
- A range is appropriate given the subjective and short term nature of inputs, classifications and allocations
- Some times rebalancing may be required
  - Revenue shift recoveries between customer groups

    (Reduce one customer group's rates and increase another group's rates)

Resulting RC Ratios from COSA

Class	RC Ratio
Residential	98.4%
Small Commercial (20)	102.2%
Commercial (22)	104.7%
Large Commercial (30)	104.0%
Large Comm. Transmission	107.0%
Wholesale Primary	96.7%
Wholesale Transmission	103.9%
Irrigation	97.2%
Lighting	92.2%

Proposed Rebalancing



Designing Rates

Customer Related Costs

Demand Related Costs

Energy Related Costs

Customer Charge

Demand Charge

Energy Charge

How we design our customers rates

Summary

- COSA developed using 2017 test year
- COSA methods are consistent with 2009 as approved
- RC Ratios outside the range of reasonableness used to determine the need for rebalancing
- COSA results are one of the many considerations when designing rates

Next Steps

- Current Window for Stakeholder Input
  - October 31,2017
- Application Filing
  - Full Application
  - Supporting Documentation
  - COSA Model

For further information, please contact:

Electric.Regulatory.Affairs@fortisbc.com

www.fortisbc.com/ratedesign

Find FortisBC at:

Fortisbc.com

604-576-7000

FORTIS BC™

Appendix F

CONSULTATION FEEDBACK

FORTIS BC
Energy at work

Please leave us with your feedback

- we support energy conservation & wise use of energy
- we have an energy efficient home built in 2011 but are solely dependant on electricity for space & water heating
- we can live within (most times) the Block 1 1600 Kwhr for April – October but consume much more power over winter for heating generally between 6-12 Mwhr incremental for the 2 coldest months of the year
- the 1600 Kwhr threshold is unfair to residents who have no access to NG for heating. It is discriminatory.
- such a rate structure encourages people to burn wood which can lead to health problems due to smoke accumulation where there are inversion conditions
- there could be a new customer class for residents with no access to NG for space & water heating. You may consider this too much fine tuning, but it is a significant portion of the resident population and it is intrinsically unfair and very discriminatory.
- Thank You for the opportunity to register our views and look forward to your new ideas to address this unfairness in a reasonable manner

If you would like to be advised of activity related to the 2017 COSA and Rate Design, please provide the information below:

Name: [redacted]

Address:

Email Addre

FORTIS BC
Energy at work

Please leave us with your feedback

customer segmentation - residential - with nat. gas
- without nat. gas.

Current two-tier system applied to residential customers without above breakdown is discriminatory which is counter to UCA + mission statement + Fortis's "Rate Design Principles"

If you would like to be advised of activity related to the 2017 COSA and Rate Design, please provide the information below:

Name: [redacted]

Address:

Email Add

FORTIS BC
Energy at work

Please leave us with your feedback

In my travels around my constituency I'm continually met with stories of hardship due to the 2-Tier electrical pricing. The Foodbank in Greenwood has been unable to cope with the increase in attendance and as quoted on CBC radio "People, after paying for their power, don't have enough left for food".

The young native lady working at the 7-11 in Oliver this past winter was fighting back tears... explaining to the customer in front of me that she + her husband had turned off the power in 2/3rds of their Mobile home and were huddled in the living room trying to stay warm.. but got a $1,200.00 power bill, with a disconnection notice!

Many, many others have related similar stories to me and I'm becoming more and more social problems including homelessness and desperation.

We, in local government, understand that Fortis is not in the business of social engineering... but you must realize the seriousness that we face in our constituency.

I would urge both Fortis and the BCUC reconsider the R.C.R. and possibly move the 1600 point for the 2nd tier up somewhat.

Time of Use metering could be helpful.

If you would like to be advised of activity related to the 2017 COSA and Rate Design, please provide the information below:

Name: [redacted]

Address:

Email Add

FORTIS BC
Energy at work

Please leave us with your feedback

If you would like to be advised of activity related to the 2017 COSA and Rate Design, please provide the information below:

Name:_[redacted]

Addres[redacted]

Email A[redacted]

Please leave us with your feedback

Would have liked to see more raw data available on percentages diplayed. also to no gas access customers as being to much bother to track was not informative as too the losistical issues around that. More information on no access gas issues and designation on gas & non gas users also tech required for a system like that on modification of existing system to do that task.

If you would like to be advised of activity related to the 2017 COSA and Rate Design, please provide the information below:

Name: [redacted]

Address [redacted]

Email Ad [redacted]

[redacted] [redacted]

FORTIS BC
Information Session
Osoyoos – July 26, 2017

July 26, 2017

Fortis Rate Review Session

Dear Madam or Sir,

Attached is a letter about the current matter under review.

This analysis shows that the current Fortis BC RCR rate structure does not encourage, and indeed does not reward, electricity conservation. In our case, using data up to 2016, we have reduced our annual electrical consumption by 23% while facing a 108% increase in costs from 2007 to 2016, from FORTIS BC.

Your current rate structure is discriminatory, it does not encourage energy conservation and it does not support the environmental objectives set by the Province of BC. This structure is forcing people to burn fossil fuels to avoid buying electricity at discriminatory prices.

Please add this letter along with the table and chart page to the official record of this proceeding.

Yours Truly,

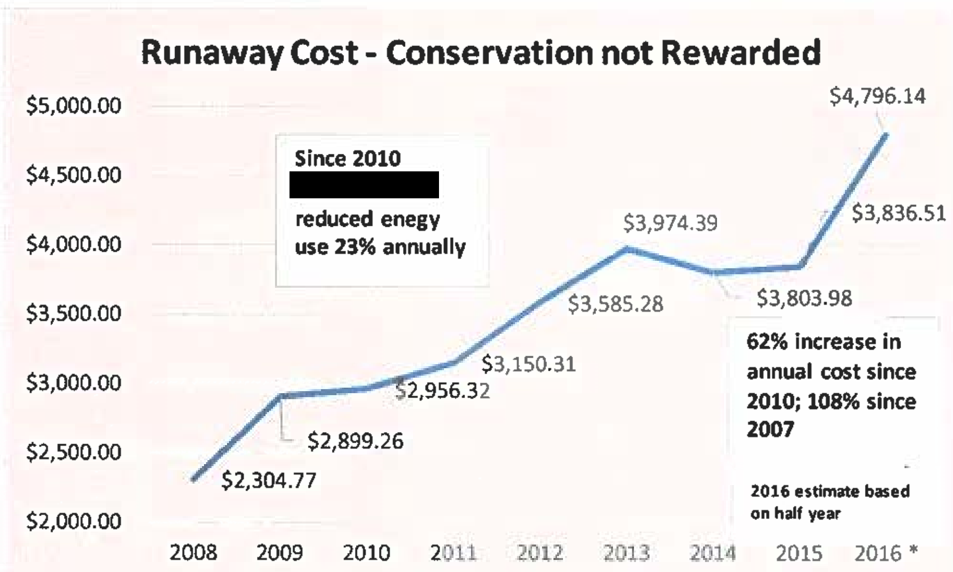
[redacted]

cc. BCUC Secretary

[redacted]

[redacted]

[redacted]



[redacted] - Actual Billings / Costs				
	Annual Cost	Annual KW	Ave.$/KWHr	
2008	$ 2,304.77	42,064	$0.071	
2009	$ 2,899.26	43,463	$0.074	
2010	$ 2,956.32	44,082	$0.082	
2011	$ 3,150.31	41,484	$0.082	
2012	$ 3,585.28	40,307	$0.109	
2013	$ 3,974.39	38,656	$0.123	
2014	$ 3,803.98	37,012	$0.128	
2015	$ 3,836.51	35,439	$0.132	
2016 *	$ 4,796.14	33,794	$0.141	
Half Year	$ 2,398.07			
		-23%		
* Full 2016 estimated based on 1/2 year to June 2016 costs				
Annual cost increase since 2008			62%	
		Cost increase since 2007		108%
		Energy Decrease since 2010		
		23%		

Sinclair, Corey

From: conversations
Sent: September-18-17 9:10 PM
To: Mason, Matt
Subject: FW: [External Email] - Two Tier Rate System

-----Original Message-----
From: [redacted]
Sent: Monday, September 18, 2017 10:53 AM
To: conversations
Subject: [External Email] - Two Tier Rate System

** THIS IS AN EXTERNAL EMAIL ** Use caution before opening links / attachments.

Re; Fortis information sessions Osoyoos 2017

Hi,
We have attended all the Fortis presentations held both on Anarchist Mountain and at the Watermark facility here in Osoyoos regarding the rates for electricity.

We live on [redacted] and do not have access to natural Gas in order to heat our homes in the winter.
Our electricity bills go from a low in the Summer months of $98 to $900 in the winter months. We have a business in town so we are not at our home for 5 days during the week, in the winter we turn the thermostat down to 15C and when we get home turn it up to 18/19 C and layer up yet our bill is $900.

Of course most of that bill is in the two tier rate because we do not have access to natural gas - we feel that this is completely discriminatory as we have no other choice.

While we could put in wood burning stove this is not the way to go because of the environment.
We are suggesting that we go to a flat rate instead of this unacceptable two tier system which results in these astronomic bills.

The house is new, well insulated and operates with energy saving appliances - what more can we do to reduce consumption - Nothing.

Sincerely

[redacted]
Osoyoos
[redacted]

Sinclair, Corey

From: conversations
Sent: September-18-17 9:09 PM
To: Mason, Matt
Subject: FW: [External Email] - Feedback

-----Original Message-----
From: [redacted]
Sent: Saturday, September 16, 2017 8:04 PM
To: conversations
Subject: [External Email] - Feedback

** THIS IS AN EXTERNAL EMAIL ** Use caution before opening links / attachments.

Hello some feed back:
The two tier system is very problematic and potentially discriminatory against those that have family commitments at certain times or personal limitations when they can do certain things.

As long as fortis(bchydro) can sell electric then they shouldn't raise rates.

Also if any maintenance or upkeep is required to structures etc then that should be done before any profits are considered. Never heard of it done so badly before

Sent from my iPhone

Sinclair, Corey

From: conversations
Sent: September-14-17 11:22 AM
To: Mason, Matt
Subject: FW: [External Email] - Fortis rate design application

-----Original Message-----
From: [redacted]
Sent: Thursday, September 14, 2017 11:19 AM
To: conversations <conversations@fortisbc.com>
Cc: [redacted]
Subject: [External Email] - Fortis rate design application

** THIS IS AN EXTERNAL EMAIL ** Use caution before opening links / attachments.

Two-tier rates are not encouraging efficient behaviour and are discriminating against customers using electricity for space and water heating. The best rate option is a return to a flat rate.

[redacted]
Osoyoos

Sent from my iPad

Sinclair, Corey

From:	conversations
Sent:	September-14-17 11:22 AM
To:	Mason, Matt
Subject:	FW: [External Email] - Comment on Rate Review

From: [redacted]
Sent: Thursday, September 14, 2017 11:20 AM
To: conversations <conversations@fortisbc.com>
Subject: [External Email] - Comment on Rate Review

**** THIS IS AN EXTERNAL EMAIL **** Use caution before opening links / attachments.

In my analysis of the two-tier rate structure, this is not encouraging efficient behaviour and does not show evidence of promoting conservation. Further , I believe these rates are discriminating against customers using electricity for space and water heating where there are no alternatives to alternate energy efficient and environmentally less harmful fuel like natural gas compared to wood or oil fired fuels. The best option would be a return to a flat rate structure (with optional time-of-use)

[redacted]
Osoyoos, BC, Canada
[redacted]

October 17th, 2017

Fortis BC
1290 Esplanade
PO Box 130
Trail, BC V1R 4L4

ATTENTION: Corey Sinclair

Dear Sir

RE: FortisBC Electricity Account [redacted]

I read your letter and would like to comment.

#1 Small business are having a difficult time utilizing your companies services because your rates have increased considerably in the past 10 years. Please provide me with a percent increase for my firm since 2008. This will assist me in determining if I want to proceed with this business or not.

#2 As to the change up, you say that your firm is revenue neutral in this new plan....is mine or am I going to pay more?

#3 If I am not operating at peak, you still intend Demand Charges even after I quit...right. How can we small business be expected to pay after we stop for something that does not exist (demand)

#4 If you use one level, we can plan our costing, but demand on small and seasonal users should not exist.

Convince me that your new system will not cost us more money for the same amount of power used.

I await your response.

Yours truly,

[redacted]

Rock Creek, BC V0H 1Y0

[redacted]

October 19, 2017

Corey Sinclair

electricratedesign@fortisbc.com

As a manager and part owner of [redacted] I have a problem with your reasons for a rate design increase in fees charged to commercial RS21 accounts. You state that "the last rate design application was in 2009 when the rate was changed from a 3step declining block rate to a 2 pricing level rate". This is not an accurate statement because we also pay a "a demand and a basic charge" and with a rate increase every year, this amounts to a 4 or 5 step rate. You"propose to complete the transition from declining block rates to a flat rate" for RS21 accounts however earlier you stated that in 2009 this rated was changed already – don't use this as a reason to do a rate increase if this is not true.

You also state that "declining block rates do not encourage conservation". This is absurd as we are intelligent and educated people who do everything we can to conserve whenever possible especially as our living costs are increasing at an alarming rate. Our apartment building has individual meters for each suite and for the building. The majority of our tenants are seniors and middle aged adults. Many of our retired tenants are on limited incomes,have increasing health issues,some have applied for government programs to help with their rent(more than 50% of their income is for rent), and others have moved to smaller/cheaper suites within or to other buildings. Any increases we face have to be passed on to our tenants through rent increases and we are restricted by how much we can charge.

Our building has tried to reduce our energy consumption since 1978 by registering for any programs offered through our electricity provider (using 2 instead of 4 fluorescent tubes in our common areas, using energy efficient bulbs, changing ballasts to use smaller compact fluorescent tubes etc.).

You also state that "any changes from the rate design are revenue neutral". This is another absurd statement because your company would be out of business if you weren't making money- we all know that the costs of living- supplies,maintenance costs keeps going up, the fees per kwh would not increase if this was true. Since 2009 our building was in the wrong category and it was only when your company recently looked into the matter that we were put into the RS21 account. I can only imagine how much we were overcharged. In fact Fortis BC has increased their costs to their consumers every year-more than the cost of living (2017 – 2.76 %). We can only raise our rent by a certain amount as dictated by government regulations. The increase for 2017 was 3% and we also face increases in rates with insurance, monthly elevator maintenance, yearly fire alarm inspection fees, municipal sewer/water/ tax fees. While homeowners can choose to use natural gas or alternative sources of energy to reduce costs, our apartment building cannot.

I understand that costs need to increase but at a reasonable rate. In my opinion Fortis BC does not understand this concept as your rates have increased considerably for many years. Perhaps if Fortis BC did not have a monopoly on electricity and natural gas commodities, they might listen to and consider the needs of their customers more. Even the BC Utilities Commission is at fault because they always seem to give in to your demands to increase costs whenever possible, and enough is enough.

Yours truly,

[redacted]

Village of Kaslo
Incorporated 1893

July 13th[th] 2017

Certified to be a true resolution of the Council of the Village of Kaslo on July 11th, 2017:

Whereas in the fall of 2017, FortisBC will be submitting an electricity rate design application to the British Columbia Utilities Commission (BCUC) to determine how customers will be billed for the electricity they use;

And whereas two-tier rate billing practices have been argued to be:

- failing to meet their stated objective of achieving an optimal level of conservation and energy efficiency;
- failing to target energy inefficient customers as an appropriately designed "conservation" rate should;
- charging higher rates to energy efficient customers while charging lower rates to energy inefficient customers;
- price discriminating against customers who are solely reliant on electricity for space and water heating, charging them rates above the cost of new electricity generation;
- charging higher rates to the 5% of customers who consume the most electricity per household (because they use electricity for heating) in order to subsidize the rates of the majority of customers (who use fossil fuels rather than electricity for heating);
- producing results that are contrary to the objectives of the Provincial Energy Plan, forcing electric heat customers to switch from renewable, emission-free hydro to natural gas, wood and heating oil, thereby increasing greenhouse gas emissions and harmful air particulates.

Therefore, be it resolved that Council submit to the BCUC and Fortis BC its position that any new electricity rate design be structured to incentivize the use of efficient electric heating and eliminate price discrimination against customers with the smallest carbon footprint.

Neil Smith
Chief Administrative Officer

Box 576, Kaslo, British Columbia V0G 1M0

Tel. 250-353-2311 Fax. 250-353-7767
E-mail: admin@kaslo.ca
http://www.kaslo.ca

The Village of
Midway

October 20, 2017

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Re: FortisBC Electricity Rate Application to determine how customers will be billed

To Whom It May Concern:

It was brought to the attention of the Village of Midway Mayor and Council at their regular meeting of Monday, October 16, 2017 that FortisBC Inc. is considering changes to Rate Schedule 21 – Commercial (RS21) by moving away from a rate with 2 pricing levels and towards a simple flat rate where all energy use is charged at the same rate. FortisBC Inc. claims that this change to the Rate Design will be revenue neutral but Council feels they may be side-stepping the processes in place in order to achieve a rate increase.

If the application is approved, Council is requesting that the BCUC review this flat rate billing structure after one-year to determine if electrical costs have increased for Fortis' commercial users as a result of this change, or if they have remained revenue neutral.

Yours truly,

VILLAGE OF MIDWAY

Per:

Penny Feist
Chief Administrative Officer

Cc: FortisBC Inc. Regulatory Affairs

PO Box 160, Midway BC, V0H 1M0 I 250.449.2222 I midwaybc@shaw.ca I www.midwaybc.ca

Appendix G

BLACKLINED FBC ELECTRIC TARIFF

FORTISBC INC.

ELECTRIC TARIFF

FOR SERVICE IN THE WEST KOOTENAY AND OKANAGAN AREAS

GENERAL TERMS AND CONDITIONS

AND

RATE SCHEDULES

EXPLANATION OF SYMBOLS APPEARING ON TARIFF PAGES
A – signifies Increase
C – signifies Change
D – signifies Decrease
N – signifies New
O – signifies Omission
R – signifies Reduction

INDEX **Page**

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Deleted: TERMS AND CONDITIONS TC1-30¶
RATES¶

GENERAL TERMS AND CONDITIONS

FortisBC will furnish electric Service in accordance with the Rate Schedules and these General Terms and Conditions filed with and approved by the British Columbia Utilities Commission. Copies are available on FortisBC's web site or upon request.

Deleted: The Company

Deleted: the Company

The Customer, by taking Service, agrees to abide by the provisions of these General Terms and Conditions.

Unless the context indicates otherwise, in the General Terms and Conditions and Rate Schedules of FortisBC the following words have the following meanings:

1. DEFINITIONS

Advanced (or AMI) Meter	An Electricity meter with integrated wireless transmit functions and those functions are activated.
Billing Demand	The Demand used in establishing the Demand portion of billing for Service during a specific billing period.
British Columbia Utilities Commission	Means the British Columbia Utilities Commission constituted under the Utilities Commission Act of British Columbia and includes and is also a reference to (a) any commission that is a successor to such commission, and (b) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the Utilities Commission Act of British Columbia.
Business Day	Means a Day that commences on other than a Saturday, a Sunday, or a statutory holiday in the Province of British Columbia.
Commercial Service	Service for business, commercial, institutional, or industrial use. Commercial Service is available as an alternative to Residential Service only in the circumstances described in Section 6.3.1 (Partial Commercial Use). FortisBC may require documentation to support Commercial use of a Premises for the purpose of being billed at Commercial Service rates.
Company Contribution	Means FortisBC's financial contribution towards the Extension Cost as specified in Section 16 (Extensions).

Moved down [10]: Customer Charge

Deleted: Application Charge

Contract Demand	The Demand reserved for the Customer by FortisBC and contracted for by the Customer.
Customer	Means a Person who is being provided Service or who has filed an application for Service with FortisBC that has been approved by FortisBC.
Customer Charge	Means a fixed charge required to be paid by a Customer for Service as specified in the applicable Rate Schedule.
Customer Portion of Costs (CPC)	Means the Extension Cost less the Company Contribution towards the Extension.
Day	Means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the applicable Service Agreement.
Demand	The rate of delivery of Electricity measured in kilowatts (kW), kilovolt-amperes (kVA), or horsepower (hp) over a given period of time.
Drop Service	The portion of an overhead Service connection extending not more than 30 metres onto the Customer's property and not requiring any intermediate support on the Customer's property.
Electricity	Means both electric Demand and electric Energy or either, as the context requires.
Energy	Electric consumption measured in kilowatt hours (kWh).
Extension	Means an addition to, or extension of, FortisBC's distribution system including an addition or extension on public or private property.
Extension Cost	Means FortisBC's estimated cost of constructing an Extension including the cost of labour, material and construction equipment. Extensions Cost includes the cost of connecting the Extension to FortisBC's distribution system, inspection costs, survey costs, and permit costs. If, in FortisBC's opinion, upgrades to FortisBC's distribution system would be beneficial for Service to other Customers, the extra cost of this reinforcement is excluded from the Extension Cost.
Financing Agreement	An agreement under which FortisBC provides financing to a Customer for improving the energy efficiency of a Premises, or a part of a Premises.

Deleted: the Company

Moved (insertion) [10]

Deleted: The term used to m

Deleted: e

Deleted: unless

Deleted: otherwise

Deleted: the Company

FortisBC	Means FortisBC Inc., a body corporate incorporated pursuant to the laws of the Province of British Columbia under number 0778288.
FortisBC System	Means the Electricity transmission and distribution system owned and operated by FortisBC, as such system is expanded, reduced or modified from time to time.
Hour	Means any consecutive 60 minute period.
Landlord	Means a Person who, being the owner of real property, or the agent of that owner, who has leased or rented the property to a Tenant.
Load Factor	The percentage determined by dividing the Customer's average Demand over a specific time period by the Customer's maximum Demand during that period.
Loan	The principal amount of financing provided by FortisBC to a Customer, plus interest charged by FortisBC on the amount of financing and any applicable fees and late payment charges.
Meter Set	Means an assembly of FortisBC owned metering, including any ancillary equipment.
Month or Monthly	Means a period of time, for billing purposes, of 27 to 34 consecutive Days. For greater clarity, the term "one month" (unless a calendar month is specified) as used herein and in the Rate Schedules, normally means the time elapsed between the meter reading date of one calendar month and that of the next. The term "two-month period" or bimonthly as used herein and in the Rate Schedules, normally means the time elapsed between the meter reading date of one calendar month and the second following calendar month.
Person	Means a natural person, partnership, corporation, society, unincorporated entity or body politic.
Power Factor	The percentage determined by dividing the Customer's Demand measured in kilowatts by the same Demand measured in kilovolt-amperes.

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Point of Delivery	The first point of connection of FortisBC's facilities to the Customer's conductors or equipment at a location designated by or satisfactory to FortisBC, without regard to the location of FortisBC's metering equipment.
Premises	A dwelling, a building, or machinery together with the surrounding land.
Radio-off AMI Meter	An Advanced (or AMI) Meter with integrated wireless transmit functions disabled.
Radio-off Customer	Customers that have a Radio-off AMI Meter installed at their Customer Premises.
Rate Schedule	Means a schedule attached to and forming part of these General Terms and Conditions, which sets out the charges for Service and certain other related terms and conditions for a class of Service.
Residential Premises	Means a Premises used for residential and housekeeping requirements, including: (a) single family dwelling, including any outbuildings supplied through the same meter; (b) single or individually metered single-family townhouse, rowhouse, condominium, duplex or apartment, carriage house, farm building, or manufactured home; (c) at FortisBC's discretion, any other types of living quarters.
Residential Service	Except as provided for in Section 6.3.1 (Partial Commercial Use) and Section 6.3.2 (Other Use), means Service for use at a Residential Premises, including a Residential Premises where a portion is used to carry on a business.
Rider	Means an additional charge or credit attached to a rate.
Service	Means the provision of Electricity or other service by FortisBC.
Service Agreement	Means an agreement between FortisBC and a Customer for the provision of Service.
Suspension	The physical interruption of the supply of Electricity to the Premises independent of whether or not the Service is terminated.

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Temporary Service	Means the provision of Service for what FortisBC determines will be a limited period of time.
Tenant	Means a Person who has the temporary use and occupation of real property owned by another Person.
Transformer	Includes transformers, cutouts, lightning arrestors and associated equipment, and the labour to install.
Transmission Voltage	A nominal potential greater than 35,000 volts measured phase to phase.
Termination	The cessation of FortisBC's ongoing responsibility with respect to the supply of Service to the Premises independent of whether or not the Service is suspended.
Primary Voltage	A nominal potential of 750 to 35,000 volts measured phase to phase.
Secondary Voltage	A nominal potential of 750 volts or less measured phase to phase.
Year	Means a period of 12 consecutive Months totalling at least 365 Days.

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2. APPLICATION FOR SERVICE

2.1 Application Requirements

Applications for Service will be made via FortisBC's contact center, online at www.fortisbc.com, or by other means acceptable to FortisBC. Applicants for Service will pay the connection or other charges required pursuant to these General Terms and Conditions and Rate Schedules, and will supply all information relating to load, supply requirements and such other matters relating to the Service as FortisBC may require.

Applicants will be required to provide information and identification acceptable to FortisBC.

Applicants may be required to sign an application form for Service. A contractual relationship will be established by the taking of Service in the absence of an application for Service or a signed application, except where a theft of Service has occurred.

A Customer will not transfer or assign a Service application or contract or a Financing Agreement without the written consent of FortisBC.

Applications for Residential Service involving a standard connection of Service should be made via telephone or internet at least ten working Days before Service is required for Contact Centre account set-up. Applications involving the installation of facilities should be discussed with the local FortisBC representative well in advance of the date that Service is required.

2.2 Rate Classification

FortisBC will assist in selecting the Rate Schedule applicable to the Customer's requirements, but will not be responsible if the most favourable rate is not selected. Changing of Rate Schedules will be allowed only if a change is deemed to be more appropriate to the Customer's circumstances. One request to change Rate Schedules will be permitted in any 1 Month period.

At FortisBC's option, where the Customer's load characteristics warrant, Customers served under Rate Schedule 20 may be transferred to Rate Schedule 21 or vice versa.

2.3 Refusal of Application

FortisBC may refuse to accept an application for Service for any of the reasons listed in Section 10.2 (Refusal of Service and Suspension of Service).

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<#>the Customer's facilities are not satisfactory to the Company;¶
<#>the applicant or owner or occupant of the Premises has an unpaid account for Service or an unpaid amount under a Financing Agreement;¶
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2.4 Rental Premises

In the case of rental Premises FortisBC may:

(a) require a Landlord who wishes FortisBC to contract directly with a Tenant to enter into an agreement with FortisBC whereby the Landlord assumes responsibility for that Tenant's non-payment for Service to the Premises;

(b) contract directly with the Landlord as a Customer of FortisBC with respect to any or all Services to the Premises; or

(c) contract directly with each Tenant as a Customer of FortisBC.

2.5 Security Deposit for Payment of Bills

If a Customer or applicant cannot establish or maintain credit to the satisfaction of FortisBC, the Customer or applicant may be required to make a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC. As security for payment of bills, all Customers who have not established or maintained credit to the satisfaction of FortisBC, may be required to provide a security deposit or equivalent form of security, the amount of which may not:

(a) be less than $50; and

(b) exceed an amount equal to the estimate of the total bill for the two highest consecutive Months consumption of Electricity by the applicable Premises.

2.5.1 Interest

FortisBC will pay interest to a Customer on a security deposit at the rate and at the times specified in Section 8.8 (Payment of Interest). Subject to Section 2.5.4 (Application of Deposit), if a security deposit in whole or in part is returned to the Customer for any reason, FortisBC will credit any accrued interest to the Customer's account at that time.

No interest is payable:

(a) on any unclaimed deposit left with FortisBC after the account for which it is security is closed; and

(b) on a deposit held by FortisBC in a form other than cash.

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2. APPLICATION FOR SERVICE (Cont'd)

2.5.2 Refund of Deposit

A security deposit may be returned to the Customer at any time if, according to the records of FortisBC, the Customer has at all times during the immediately preceding one Year period maintained an account with FortisBC and paid in full all amounts when due in accordance with the Service Agreement. When the Customer pays the final bill, FortisBC will refund any remaining security deposit plus any accrued interest or cancel the equivalent form of security.

2.5.3 Unclaimed Refund

If FortisBC is unable to locate the Customer to whom a security deposit is payable, FortisBC will take reasonable steps to locate the Customer; but if the security deposit remains unclaimed 10 Years after the date on which it first became refundable, the deposit, together with any interest accrued thereon, will become the absolute property of FortisBC.

2.5.4 Application of Deposit

If a Customer's bill, including the Loan amount, is not paid when due, FortisBC may apply all or any part of the Customer's security deposit or equivalent form of security and any accrued interest toward payment of the bill. Even if FortisBC applies the security deposit or calls on the equivalent form of security, FortisBC may, under Section 10.2 (Refusal of Service and Suspension of Service), discontinue Service to the Customer for failure to pay for Service on time.

2.5.5 Replenish Security Deposit

If a Customer's security deposit or equivalent form of security is called upon by FortisBC towards paying an unpaid bill, the Customer may be required to re-establish the security deposit or equivalent form of security before FortisBC will reconnect or continue Service to the Customer.

2.5.6 Failure to Pay

Failure to pay a security deposit or to provide an equivalent form of security acceptable to FortisBC may, in FortisBC's discretion, result in discontinuance or refusal of Service as set out in Section 10.2 (Refusal of Service and Suspension of Service).

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3. TERM OF SERVICE AGREEMENT

3.1 Term of Service

Unless otherwise specifically provided in these General Terms and Conditions, the Rate Schedules, or in any contract between the Customer and FortisBC, the term of Service and obligation to pay the charges under the applicable Rate Schedule for the minimum required term of Service will commence on the Day when FortisBC's Service is connected to the Customer's installation for the purpose of supplying Electricity, and

(a) will be for one Year where the connection does not require more than a Drop Service, unless a shorter period is agreed to by FortisBC; or

(b) will be for five Years where additional facilities other than those for a Drop Service are required; and

(c) will continue thereafter until canceled by written notice of Termination by either party, except that in the case of Customers whose Contract Demand exceeds 200 kVA, 12 Months' prior written notice of Termination will be required and will be given in such manner that the contact terminates with the last Day of a billing period.

3.2 Delay in Taking Service

If, with respect to an application to extend its facilities to any Point of Delivery, FortisBC has reason to believe that Service through that Point of Delivery will not be taken within 30 Days after such Service is available, then FortisBC, in addition to any other payment required, may require payment equivalent to FortisBC's investment, subject to prior written notification to the affected Customer by FortisBC. The payment will be comprised of a monthly charge based on FortisBC's investment multiplied by 2% to provide for a return on investment, depreciation, taxes and other fixed costs.

3.3 Termination of Service Agreement

3.3.1 Termination by Customer

Unless the Service Agreement or applicable Rate Schedule specifies otherwise, the Customer may terminate the Service Agreement after the end of the initial term by giving FortisBC timely notice, and no less than 48 Hours, so that arrangements can be made for final meter reading and billing. Until notice of Termination is given, the Customer will continue to be responsible for all Service supplied unless FortisBC receives an application for Service from a new Customer for the Premises concerned.

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3.3.2 Contract Termination by Customer

Notice of Termination requirements for contract Customers will be in accordance with the terms of the contract. If a contract Customer terminates the contract but fails to give the required notice of Termination, the minimum charges for the notice period, as well as any amounts due for Service supplied, will immediately become due and payable.

3.3.3 Effect of Termination

The Customer is not released from any previously existing obligations to FortisBC under a Financing Agreement by terminating the Service Agreement with FortisBC.

3.3.4 Termination by FortisBC

Unless the Service Agreement or applicable Rate Schedule specifies otherwise, FortisBC may terminate the Service Agreement for any reasons by giving the Customer at least 48 Hours written notice.

3.4 Reconnection of Service

If:

(a) Service is terminated:

(i) at the request of a Customer; or

(ii) for any of the reasons described in Section 10.2 (Refusal of Service and Suspension of Service); or

(iii) to permit Customers to make alterations to their Premises; and

(i) the same Customer or the spouse, employee, contractor, agent or partner of the same Customer requests reconnection of Service to the Premises within one Year, the applicant for reconnection must pay the reconnection charge plus the total of the minimum charges set out in the applicable Rate Schedule which would have been paid by the Customer between the time of termination and the time of reconnection of Service.

If a Service has been disconnected for over 90 Days, or the electrical use within the building has changed substantially, an Electrical Inspection Department permit may be required before reconnection.

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4. CONDITIONS OF SERVICE

4.1 Connection of Drop Service

FortisBC will connect a Drop Service to the Customer's Premises after:

(a) receipt of an application for Service;
(b) payment of any applicable charges and deposits;
(c) an Electrical Inspection Department permit to connect Service; and
(d) other permits as may be required by others or by FortisBC.

If space for a Drop Service to the Customer's Premises most convenient to FortisBC is obstructed, FortisBC will charge the Customer for the additional cost of providing Service.

4.2 Connection Requiring Extension

For Service connections requiring more than a Drop Service, the provisions of Section 16 (Extensions) will apply.

4.3 Point of Delivery

Unless otherwise specifically agreed to, the Point of Delivery is the first point of connection of FortisBC's facilities to the Customer's conductors or equipment at a location designated by or satisfactory to FortisBC, without regard to the location of FortisBC's metering equipment.

FortisBC, at its option, may supply Commercial Service through one Point of Delivery to two or more adjacent buildings owned and used as a single business function.

The Rate Schedule for each class of Service named in this tariff is based upon the supply of Service for each Customer through a single Point of Delivery. Additional Service supplied to the same Customer at more than one Point of Delivery will be permitted only at the discretion of and under terms acceptable to FortisBC.

4.4 Ownership of Facilities

Subject to any contractual arrangement and, notwithstanding the payment of any Customer contribution toward the cost of facilities, FortisBC will retain full title to all equipment and facilities installed and maintained by FortisBC.

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4.5 Customer Contributions

The Customer may be required to make a contribution as determined under Section 16 (Extensions) toward the cost of facilities in excess of the minimum charges for installation of new/upgraded Services provided for under Section 17 (Standard Charges Schedule) under any of the following conditions:

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(a) Extension of Service is in excess of a Drop Service as provided in Section 16 (Extensions);

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(b) Service is underground as specified under Section 6.2 (Underground Service);

(c) The nature of the Service is such that the revenue derived from the minimum billing would be insufficient to cover the cost of Service. A contribution would be required for such Services as fire pumps, sirens or emergency supply where the level of consumption is below that necessary to cover the annual costs;

(d) Space for a Drop Service to the Customer's Premise most convenient to FortisBC is obstructed by the Customer's property; or

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(e) Facilities must be upgraded significantly to meet an increase in the Customer's load.

If a Customer contribution is required and if the Customer does not receive Service within three Months of the contribution being received by FortisBC, and where the delay in taking Service is not attributable to the Customer, the Customer will receive interest as calculated in Section 8.8 (Payment of Interest) on such payment.

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4.6 Revenue Guarantee Deposit

If the provision of Service by FortisBC to a non-residential Customer will require construction and installation costs by FortisBC of more than $5,000 per Customer supplied, FortisBC may require each such Customer to provide a revenue guarantee deposit, as assurance that FortisBC will receive sufficient revenue to recover the installation costs of the facilities.

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FortisBC will repay 20 percent of the revenue guarantee to the Customer at the end of each Year of Service, for a period of five Years, provided that the Customer's bills are paid in full at the time the refund is due. Interest will be paid on refunds as calculated in Section 8.8 (Payment of Interest).

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If the contract for Service is terminated prior to five Years from the date of installation, any balance of the revenue guarantee remaining will belong to FortisBC absolutely as part of the consideration for FortisBC installing Service.

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4.7 Limitation of Use

Service supplied to a Customer will be for the use of that Customer only and for the purpose applied for, and will not be remetered, submetered or resold to others except with the written consent of FortisBC or as provided in the applicable Rate Schedule.

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5. SERVICE CHARACTERISTICS

5.1 Voltages Supplied

FortisBC will supply nominal 60 cycle alternating electric current to the Point of Delivery at the available phase and voltage.

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Before wiring Premises or purchasing any electrical equipment, the Customer should consult with FortisBC to ascertain what type of Service may be available at the requested location. The Customer should present a description of the load to be connected so that FortisBC can furnish information regarding voltage and phase characteristics available at the Point of Delivery.

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FortisBC will not supply transformation from one Secondary Voltage to another Secondary Voltage.

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FortisBC reserves the right to determine the voltage and amperage of the Service connection.

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5.1.1 Nominal Standard Secondary Voltage from Pole-Mounted Transformers

Single phase	120/240 volts 3 wire maximum 400 amperes.
Three phase	120/208 volts; 4 wire; 300 kVA maximum transformation capacity
	347/600 volts; 4 wire; maximum 300 kVA transformation capacity.

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5.1.2 Nominal Standard Secondary Voltage from Pad-Mounted Transformers

Single phase:	120/240 volts; 3 wire; maximum 600 amperes.
Three phase:	120/208 volts; 4 wire; maximum 500 kVA transformation capacity.
	347/600 volts; 4 wire; maximum 2,500 kVA transformation capacity.

5.1.3 Special Conditions

Special arrangements may be required under the following conditions:

(a) For Customer loads or supply voltages different from those listed above with pole-mounted and pad-mounted transformer installations, the Customer will be required to supply its own transformers and take Service at the available Primary Voltage;

(b) Customers initiating an upgrade of existing facilities using non standard Secondary Voltages may be required to upgrade to standard voltages at their own expense;

(c) Where a Customer has been required to supply its own transformation, transformation discounts will only be applicable if available under the existing Rate Schedule to which Service is provided to the Customer.

5.2 Customer Owned Equipment

All Customer owned transformers and equipment used to connect them to FortisBC's electrical system will be approved by and installed in a manner satisfactory to FortisBC.

Where a Customer supplies their own transformation from the primary distribution voltage, the rate for Large Commercial Service and Industrial Service will apply.

5.3 Motor Specifications

Single phase motors rated larger than two hp and other equipment with rated capacity greater than 1,650 watts will not be used on 120 volt circuits, unless otherwise authorized by FortisBC.

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Motors of 20 hp or larger will be equipped with reduced voltage starters or other devices approved by FortisBC to reduce starting current, unless otherwise authorized by FortisBC.

5.4 Space Heating Specifications

5.4.1 Residential

The maximum capacity of residential heating units to be controlled by one switch or thermostat will be 6,000 watts. Where applicable, time delay equipment must be installed so that each of the heating units, as required, is energized sequentially at minimum intervals of ten seconds.

Heating units will be connected so as to balance as nearly as possible the current drawn from the circuits at the Point of Delivery.

5.4.2 Industrial

The maximum capacity of industrial heating units to be controlled by one switch or thermostat will be ten kW for single phase and 25 kW for three-phase units.

5.5 Water Heating Specifications

The heating units will be of non-inductive design for a nominal voltage of 240 volts unless otherwise agreed to by FortisBC, but units of less than 1,650 watts may have a nominal voltage of 120 volts.

Installations may consist of either one or two-unit heaters. In the single unit heater tank, the unit will be placed to heat the entire tank. In the two-unit heater tank, a "base" unit heater will be placed to heat the entire tank and a "booster" unit heater placed to heat not more than the top third of the tank.

Each unit heater will be controlled by a separate thermostat and will not exceed 6,000 watts, except heating units installed in tanks of 350 litres and larger may, at FortisBC's option, exceed 6,000 watts but will not exceed 17 watts per litre for either "base" or "booster" unit heater.

Thermostats must be permanently connected so that both heating units cannot operate at the same time except on tanks where the installed capacity does not exceed 6,000 watts.

FortisBC, may at its expense, install a time switch, carrier current control, or other device to limit the Hours of Service to the water heater. The period or periods each Day during which Service may be so limited will not exceed a total of two Hours.

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6. TYPE OF SERVICE

6.1 Temporary Service

Where FortisBC has facilities available, Temporary Service may be supplied under any Rate Schedule applicable to the class of Service required. The Customer Charge or minimum set forth in that Rate Schedule will be applicable to the temporary Service, but in no case will it be less than one full Month.

6.1.1 Temporary to Permanent Service

The Customer will pay for the cost of the installation of a Temporary Drop Service of less than 30 meters over private property as prescribed in Section 17.1 (Installation of New/Upgraded Services) plus the charge for conversion to permanent Service as prescribed in Section 17.3 (Miscellaneous Standard Charges) provided the Temporary Service can be converted to the permanent Service at little additional cost.

6.1.2 Salvage of Temporary Service

If the Temporary Service cannot be used to form the permanent Service and must be removed, the Customer will pay for the cost of the installation of a Temporary Drop Service of less than 30 meters over private property as prescribed in Section 17.1 (Installation of New/Upgraded Services) plus the charge for salvage of the Temporary Service as prescribed in Section 17.3 (Miscellaneous Standard Charges). Following salvage of the Temporary Service, the Customer will pay for the installation of a permanent Drop Service as prescribed in Section 17.1 (Installation of New/Upgraded Services).

6.2 Underground Service

FortisBC's Tariff is designed to recover the cost of providing Service from overhead poles and conductors. A Customer applying for underground Service under any Rate Schedule will be responsible for actual costs greater than the connection of a Drop Service as specified in Section 4.5 (Customer Contributions).

6.2.1 Conditions of Underground Service

A Customer applying for underground Service agrees as follows:

(a) FortisBC will own, install and maintain the underground Service line to the Point of Delivery. The Customer will own, install and maintain the underground Service line beyond the Point of Delivery.

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(b) The underground installation must comply with FortisBC's underground distribution standards.

(c) FortisBC will not be responsible for any loss or damage beyond the reasonable control of FortisBC due to the installation, operation or maintenance of the underground circuit.

6.3 Residential Service

Residential Service is normally single phase 120/240 volt. In FortisBC's discretion, three phase Residential Service or single phase Residential Service in excess of 200 amperes may be provided under special contract terms requiring the Customer to pay all additional costs of a larger Service.

At FortisBC's option, for billing purposes multiple family dwellings used exclusively for living quarters and served through one meter, may have the kilowatt-hour blocks and customer charge increased in proportion to the number of single family living quarters served.

6.3.1 Partial Commercial Use

Where a partial Commercial use is carried on in a Residential Premises (with or without outbuildings) and the Commercial area is separately metered, the Commercial area only may be on the applicable Commercial Service rate. If new buildings are erected or major alterations are made to a Premises with partial Commercial use, the Customer may be required to arrange the wiring to provide for separate metering.

6.3.2 Other Use

Where water pumps supply single family residences, the water pumps will be on the Residential Service rate provided they can be supplied single phase and total 5 HP or less.

6.3.3 Farms

Farm residences and their outbuildings will qualify for the exempt Residential Service rate provided the farm is assessed for property tax purposes as agricultural land and the Service is used primarily for the production of food or industrial crops on that land. Other use for commercial or non-farm purposes will be billed on the Commercial Service rate.

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7. METER SETS AND METERING

7.1 Installation

FortisBC will provide all meters necessary for measuring the Customer's use of the electric Service provided by FortisBC. The meters will remain the property of FortisBC and will be maintained in accurate operating condition in accordance with the regulations of Measurement Canada.

The Customer may furnish, install and maintain, at their own expense, a meter system to verify the accuracy of FortisBC's meter system. The Customer's meter system and the manner of its installation will be approved by FortisBC.

7.2 Protection of Equipment

The Customer will exercise all reasonable diligence to protect FortisBC's meter from damage or defacement and will be held responsible for any costs of repair or cleaning resulting from defacement or damage.

7.3 No Unauthorized Changes

All connections and disconnections of electric Service and installation and repair of FortisBC's meter system will be made only by FortisBC. All meters will be sealed by FortisBC. Breaking the seals or tampering with the meter or meter wiring is unlawful and may be cause for Termination of Service by FortisBC, and may result in criminal charges for theft of Electricity.

7.4 Location

The Customer will provide a Service entrance and meter socket location in accordance with FortisBC requirements, and where required a metering equipment enclosure.

The meter socket will be located on an outside wall and be within 1 m. of the corner nearest the point of supply except, in the case of metering over 300 volts, the meter socket will be installed on the load side of the Service box and will be accessible to FortisBC personnel. All sockets must be installed between 1.4 m. and 1.7 m. above final grade to the centre of the meter. Meters will not be installed in carports, breezeways or similar areas. Any exceptions must be approved by FortisBC.

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Meters will be installed in places providing safe and reasonable access. Meters will not be exposed to live steam, corrosive vapours or falling debris. Where the meter is recessed in the wall of a building, sufficient clearance must be provided to permit removal and testing of FortisBC equipment. The full cost of relocating an inaccessible meter will be borne by the Customer.

7.5 Meter Tests or Adjustments

A Customer may request in writing a test of the accuracy of a meter. The Customer will deposit an amount as provided in Section 17.3 (Miscellaneous Standard Charges) and FortisBC will remove the meter within 10 Days and apply to the authorized authority to have the meter tested. If the meter fails to meet any of the applicable laws and regulations, the deposit will be refunded to the Customer. If the meter is found to satisfy the applicable laws and regulations, the Customer will forfeit the deposit.

If after testing the meter is found not to be registering within the limits allowed by Measurement Canada, bills will be adjusted as prescribed in the applicable laws and regulations. If a refund is necessary, it will be calculated in accordance with Section 8.8 (Payment of Interest).

7.6 Metering Selection

Meters will be selected at FortisBC's discretion and will be compliant with the regulations of Measurement Canada. FortisBC, at its discretion, may change the type of metering equipment.

7.7 Unmetered Service

FortisBC may permit unmetered Service if it can estimate to its satisfaction the energy used based on the connected load and Hours of use. Customers served under this provision must notify FortisBC immediately of any proposed or actual changes in load or Hours of use. FortisBC, at its discretion, may at any time require the installation of a meter or meters and thereafter bill the Customer on the consumption registered.

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8. BILLING

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8.1 Basis for Billing

FortisBC will bill the Customer in accordance with the Customer's Service Agreement, the Rate Schedule under which the Customer is provided Service, and the fees and charges contained in Section 17 (Standard Charges Schedule).

The Customer will pay for Electricity in accordance with these General Terms and Conditions and the Customer's applicable Rate Schedule, as amended from time to time and accepted for filing by the British Columbia Utilities Commission. If it is found that the Customer has been overcharged, the appropriate refund will be with interest as calculated in Section 8.8 (Payment of Interest).

8.2 Payment of Accounts

Bills for electric Service are due and payable when rendered. Payments may be made to FortisBC's collection office, electronically or to authorized collectors.

8.2.1 Customer Selected Bill Date

Customers will be permitted to select a bill date under the following conditions:

(a) The Customer is served with a meter with the integrated wireless transmit functions enabled and the meter is not currently manually read; and

(b) The Customer's account is not in arrears.

FortisBC will render bills to the Customer on or as close to the Customer selected bill date as possible. FortisBC, at its sole discretion, may refuse a Customer request to change a bill date.

8.2.2 Late Payments

A Customer's account, including the account under a Financing Agreement, not paid by the due date printed on the bill will be in arrears. Late payment charges may be applied to overdue accounts at the rate specified on the bill and as set out on the applicable Rate Schedule.

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Customers will be advised that their account is in arrears by way of notification on the next billing. If payment is not received, a letter will be mailed to the Customer advising that if payment is not received within ten Days of the date of mailing, Service may be suspended without further notice. FortisBC will make every reasonable effort to contact the Customer by telephone or in person to advise the Customer of the consequences of non-payment, but the account may be disconnected if payment is not received.

8.2.3 Sales Tax and Assessments

In addition to payments for Services provided, the Customer will pay to the Company the amount of any taxes or assessments imposed by any competent taxing authority on any Services provided to the Customer.

8.2.4 Historical Billing Information

Customers who request historical billing information may be charged the cost of processing and providing the information.

8.3 Meter Reading

Meters will be read at the end of each billing period in accordance with the applicable Rate Schedule. The interval between consecutive meter readings will be determined by FortisBC. An accurate record of all meter readings will be kept by FortisBC and will be the basis for determination of all bills rendered for Service.

8.4 Estimates

Where an accurate meter reading cannot be obtained due to meter failure, temporary inaccessibility, or any other reason, Electricity delivered to the Customer will be estimated by FortisBC from the best available sources and evidence. Where the Customer requests Termination of Service pursuant to Section 3.4 (Termination of Service Agreement), FortisBC may estimate the final meter reading for final billing.

8.5 Proration of Billing

Bills will be prorated as appropriate under the following conditions:

(a) For meters normally read every one Month where the billing period is less than 21 Days or greater than 39 Days.

(b) For meters normally read every two Months where the billing period is less than 51 Days or greater than 69 Days.

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8.6 Equal Payment Plan

Upon application, FortisBC may permit qualifying Residential Customers to pay their accounts in equal Monthly payments. The payments will be calculated to yield, over a twelve Month period, the total estimated amount that would be payable by the Customer calculated by applying the applicable Residential Service rate to the Customer's estimated consumption during the same twelve Month period. Customers may make application at any time of the year. All accounts will be reconciled annually or the earlier Termination date, at which time the amounts payable by the Customer to FortisBC for Electricity actually consumed during the equal payment period will be compared to the sum of equal payments made during the period. Any resulting amount owing by the Customer will be paid to FortisBC.

A Residential Customer may qualify for the plan provided their account is not in arrears, they have established credit to the satisfaction of FortisBC and the Customer expects to be on the equal payment plan for at least one Year.

FortisBC may at any time revise the equal Monthly installments to reflect changes in estimated consumption or the applicable Rate Schedule.

The equal payment plan may be terminated by the Customer upon reasonable notice, or by FortisBC if the Customer has not maintained their credit to the satisfaction of FortisBC. FortisBC reserves the right to cancel or modify the Equal Payment Plan Service at any time.

If a Customer on an equal payment plan has a credit balance and closes the account, FortisBC will refund the amount regardless of the size of the balance. If the Customer has not terminated their account, and the credit balance is small, it will be carried forward.

8.7 Back-billing

8.7.1 When Required

FortisBC may, in the circumstances specified in this Section 8.7 (Back-billing) charge, demand, collect, or receive from its Customers in respect of a regulated Service rendered to its Customers a greater or lesser compensation than that specified in the Rate Schedules applicable to that Service.

In the case of a minor adjustment to a Customer's bill, such as an estimated bill or a Monthly Payment Plan bill, such adjustments do not require back-billing treatment to be applied.

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8.7.2 Definition

Back-billing means the rebilling for Services rendered to a Customer because the original billings are discovered to be either too high (over-billed) or too low (under-billed). The discovery may be made by either the Customer or FortisBC, and may result from the conduct of an inspection under provisions of the federal statute, the EGI Act. The cause of the billing error may include any of the following non-exhaustive reasons or combination thereof:

(a) Stopped meter.
(b) Metering equipment failure.
(c) Missing meter now found.
(d) Switched meters.
(e) Double metering.
(f) Incorrect meter connections.
(g) Incorrect use of any prescribed apparatus respecting the registration of a meter.
(h) Incorrect meter multiplier.
(i) The application of an incorrect rate.
(j) Incorrect reading of meters or data processing.
(k) Tampering, fraud, theft or any other criminal act.

8.7.3 Application of Act

Whenever the dispute procedure of the EGI Act is invoked, the provisions of that Act apply, except those which purport to determine the nature and extent of legal liability flowing from metering or billing errors.

8.7.4 Billing Basis

Where metering or billing errors occur and the dispute procedure under the EGI Act is not invoked, the consumption and Demand will be based upon the records of FortisBC for the Customer, or the Customer's own records to the extent they are available and accurate, or if not available, reasonable and fair estimates may be made by FortisBC. Such estimates will be on a consistent basis within each Customer class or according to a contract with the Customer, if applicable.

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8.7.5 Tampering / Fraud

If there are reasonable grounds to believe that the Customer has tampered with or otherwise used FortisBC's Service in an unauthorized way, or there is evidence of fraud, theft or other criminal acts, or if a reasonable Customer should have known of the under-billing and failed to promptly bring it to the attention of FortisBC, then the extent of back-billing will be for the duration of unauthorized use, subject to the applicable limitation period provided by law and the provisions of Sections 8.7.8 (Under-billing) to 8.7.11 (Changes in Occupancy), below do not apply.

In addition, the Customer is liable for the administrative costs incurred by FortisBC in the investigation of any incident of tampering, including the direct costs of repair, or replacement of equipment.

Under-billing resulting from circumstances described above will bear interest at the rate normally charged by FortisBC on unpaid accounts from the date of the original under-billed invoice until the amount underbilled is paid in full.

8.7.6 Remedying Problem

In every case of under-billing or over-billing, the cause of the error will be remedied without delay, and the Customer will be promptly notified of the error and of the effect upon the Customer's ongoing bill.

8.7.7 Over-billing

In every case of over-billing, FortisBC will refund to the Customer all money incorrectly collected for the duration of the error, subject to the applicable limitation period provided by law. Interest will be paid in accordance with Section 8.8 (Payment of Interest).

8.7.8 Under-billing

Subject to Section 8.7.5 (Tampering / Fraud) above, in every case of under-billing, FortisBC will back-bill the Customer for the shorter of:

(a) the duration of the error; or

(b) six Months for Residential, Commercial Service, Lighting and Irrigation; and

(c) one Year for all other Customers or as set out in a special or individually negotiated contract with FortisBC.

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8.7.9 Terms of Repayment

Subject to Section 8.7.5 (Tampering / Fraud) above, in all cases of under-billing, FortisBC will offer the Customer reasonable terms of repayment. If requested by the Customer, the repayment term will be equivalent in length to the back-billing period. The repayment will be interest free and in equal installments corresponding to the normal billing cycle. However, delinquency in payment of such installments will be subject to the usual late payment charges.

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8.7.10 Disputed Back-bills

Subject to Section 8.7.5 (Tampering / Fraud) above, if a Customer disputes a portion of a back-billing due to under-billing based upon either consumption, Demand or duration of the error, FortisBC will not threaten or cause the discontinuance of Service for the Customer's failure to pay that portion of the back-billing, unless there are no reasonable grounds for the Customer to dispute that portion of the back-billing. The undisputed portion of the bill will be paid by the Customer and FortisBC may threaten or cause the discontinuance of Service if such undisputed portion of the bill is not paid.

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8.7.11 Changes in Occupancy

Subject to Section 8.7.5 (Tampering / Fraud) above, back-billing in all instances where changes of occupancy have occurred, FortisBC will make a reasonable attempt to locate the former Customer. If, after a period of one Year, such Customer cannot be located, the over- or under-billing applicable to them will be canceled.

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8.8 Payment of Interest

When interest is to be applied to certain Customer payments as provided in these General Terms and Conditions, it will be calculated as follows:

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FortisBC will pay simple interest at the average prime rate of the principal bank with which FortisBC conducts its business, commencing with the date the subject funds were received by FortisBC.

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The interest will be remitted to the Customer at the time the deposit or other payments are refunded, or in the case when a deposit or other refundable payment is to be held beyond one Year, the interest will be calculated once every 12 Months and will be applied to the Customer's account.

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9. LOAD CHANGES AND OPERATION

9.1 Notice by Customer

A Customer will give to FortisBC reasonable written notice of any change in its load requirements to permit FortisBC to determine whether or not it can meet the requirements without changes to its equipment or system.

Notwithstanding any other provision of these General Terms and Conditions, FortisBC will not be required to supply to any Customer Electricity in excess of that previously agreed to by FortisBC.

Customers with a Demand component in the Rate Schedule who wish to change the Contract Demand or the Demand limit, will submit to FortisBC a written request subject to the following provisions;

(a) an increase requested of less than 1,000 kVA will be submitted not less than three Months in advance of the date the increase is intended to become effective; and

(b) an increase requested in excess of 1,000 kVA but less than 5,000 kVA will be submitted not less than one Year in advance of the date the increase is intended to become effective;

(c) an increase requested in excess of 5,000 kVA will be submitted not less than three Years in advance of the date the increase is intended to become effective; and

(d) a decrease requested of up to 10 percent per Year of the existing Contract Demand or Demand limit will be submitted not less than three Months in advance of the date the decrease is intended to become effective. Customers with a Contract Demand in excess of 500 kVA will provide FortisBC by January 31 of each year their best estimate of their annual Electricity requirements to allow FortisBC to forecast future load on its facilities.

If FortisBC approves the request in writing, the Contract Demand or the Demand limit may be changed either by amendment to the Customer's contract or by the parties executing a new contract. FortisBC will not be required to approve any requested change in the Contract Demand or the Demand limit.

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9.2 Changes to Facilities

The Customer may be required to pay for the cost of any alterations to FortisBC's facilities necessary to provide the Customer's increased load. If any increase in load, Contract Demand or Demand limit, approved by FortisBC, requires it to add to its existing facilities for the purpose of complying with the Customer's request, the approved increase will be subject to payment of a Customer contribution under Section 4.5 (Customer Contributions). The Customer may also be required to provide a revenue guarantee deposit as set out in Section 4.6 (Revenue Guarantee Deposit).

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9.3 Responsibility for Damage

A Customer will be responsible for and pay for all damage caused to FortisBC's facilities as a result of that Customer increasing its load without the consent of FortisBC.

The Customer will indemnify FortisBC for all costs, damages, or losses arising from the Customer exceeding its Demand limit, including without limiting generality, direct or consequential costs, damages or losses arising from any penalty incurred by FortisBC for exceeding its Demand limit with its suppliers of Electricity.

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9.4 Power Factor

Customers will regulate their loads to maintain a Power Factor of not less than 90 percent lagging or as otherwise provided for in the applicable Rate Schedule. If the Power Factor of the Customer's load is less than the minimum required, the Customer's bill may be increased by an adjustment for low Power Factor. FortisBC may also require the Customer, at its expense, to install Power Factor corrective equipment to maintain the minimum required Power Factor.

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FortisBC may refuse Service for neon, mercury vapour, fluorescent or other types of outdoor lighting or display device which has a Power Factor of less than 90 percent or other detrimental characteristics.

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No credit will be given for leading Power Factor.

9.5 Load Fluctuations

The Customer will operate its motors, apparatus and other electrical equipment in a manner that will not cause sudden fluctuation to FortisBC's line voltage, or introduce any element into FortisBC's system that, in FortisBC's opinion, disturbs or threatens to disturb its electrical system or the property or Service of any other Customer. Under no circumstances will the imbalance in current between any two phases be greater than five percent. The Customer will indemnify FortisBC against any liability, loss, cost and expense occasioned by the Customer's failure to operate its electrical equipment in compliance with this section.

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10. CONTINUITY OF SERVICE

10.1 Interruptions and Defects in Service

FortisBC will endeavour to provide a regular and uninterrupted supply of Electricity but it does not guarantee a constant supply of Electricity or the maintenance of unvaried frequency or voltage and will not be responsible or liable for any loss, injury, damage or expense caused by or resulting from any interruption, Suspension, Termination, failure or defect in the supply of Electricity, whether caused by the negligence of FortisBC, its servants or agents, or otherwise unless the loss, injury, damage or expense is directly resulting from the willful misconduct of FortisBC, its servants or agents provided, however, that FortisBC, its servants and agents are not responsible for any loss of profit, loss of revenues or other economic loss even if the loss is directly resulting from the willful misconduct of FortisBC, its servants or agents.

All responsibility of FortisBC for Electricity delivered to the Customer will cease at the Point of Delivery, and the Customer will indemnify FortisBC and save it harmless from all liability, loss and expense caused by or arising out of the taking of Electricity by the Customer.

The expense of any interruption of Service to others, loss of or damage to the property of FortisBC through misuse or negligence of the Customer, or the cost of necessary repairs or replacement will be paid to FortisBC by the Customer.

10.2 Refusal of Service and Suspension of Service

FortisBC may refuse Service or demand Suspension of Service if, in the opinion of FortisBC:

(a) conditions other than standard conditions are required by the applicant;
(b) facilities are not available to provide adequate Service;
(c) the Customer's facilities are not satisfactory to FortisBC;
(d) the applicant or owner or occupant of the Premises has an unpaid account for Service or an unpaid amount under a Financing Agreement;
(e) the Customer or applicant occupies the Premises with another occupant who has failed to pay FortisBC's bill, security deposit, or required increase in the security deposit in respect of another Premises that was occupied by that occupant and the Customer at the same time;
(f) the Customer or applicant has provided false or misleading information;
(g) the Customer or applicant is not the owner or occupant of the Premises;
(h) the Customer has failed to apply for Service;
(i) the Service requested is already supplied to the Premises for another Customer who does not consent to having the Service terminated;
(j) the applicant cannot provide satisfactory security for payment as required by FortisBC;

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(k) the applicant is in receivership or bankruptcy, or operating under the protection of insolvency legislation and has failed to pay any outstanding bills to FortisBC; or

(l) the applicant has breached any agreement or terms with FortisBC.

The Company will not be liable for any loss, injury or damage suffered by any Customer by reason of a refusal to provide Service.

10.2.1 Suspension of Service for Safety, Repairs or Maintenance

FortisBC and the Customer may demand the Suspension of Service whenever necessary to safeguard life or property, or for the purpose of making repairs on or improvements to any of its apparatus, equipment or work. Such reasonable notice of the Suspension as the circumstances permit will be given.

The Company may suspend Service to the Customer for the failure by the Customer to take remedial action acceptable to FortisBC, within 15 Days of receiving notice from FortisBC, to correct the breach of any provision of these General Terms and Conditions to be observed or performed by the Customer. FortisBC will be under no obligation to resume Service until the Customer gives assurances satisfactory to FortisBC that the breach which resulted in the Suspension will not recur.

FortisBC will have the right to suspend Service to make repairs or improvements to its electrical system and will, whenever practicable, give reasonable notice to the Customer.

10.2.2 Suspension of Service Without Notice

FortisBC will have the right to suspend or terminate Service at any time without notice for any of the following reasons:

(a) the Customer has breached any agreement, including provisions of a Financing Agreement, with FortisBC;

(b) the Customer has failed to pay arrears within the specified time

(c) the Customer has fraudulently used the Service;

(d) the Customer has tampered with FortisBC's equipment or committed similar actions;

(e) the Customer has compromised FortisBC's Service to other Customers; or

(f) FortisBC is ordered by an authorized authority to suspend or terminate such Service.

The cause of any Suspension must be corrected, and all applicable charges paid before Service will be resumed.

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Suspension of Service by FortisBC will not operate as a cancellation of any contract with FortisBC, and will not relieve any Customer of its obligations under these General Terms and Conditions or the applicable Rate Schedule.

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11. RIGHTS-OF-WAY AND ACCESS TO FACILITIES

11.1 Rights-of-Way

By applying for electric Service, the Customer agrees to grant to FortisBC such rights-of-way, easements and any applicable permits on, over and under the property of the Customer as may be necessary for the construction, installation, maintenance or removal of facilities.

On request, the Customer, at their own expense, will deliver to FortisBC documents satisfactory to FortisBC in registrable form granting the rights-of-way, easements and executed permits. The Customer will, at their own expense, be responsible for obtaining rights-of-way, easements and any applicable permits on other properties necessary for FortisBC to provide Service to the Customer.

Notwithstanding payment by the Customer towards the cost of electrical facilities installed by FortisBC or that electrical facilities may be affixed to the Customer's property, all electrical facilities installed by FortisBC up to the Point of Delivery will remain the property of FortisBC, and FortisBC will have the right to safe and ready access to upgrade, renew, replace or remove any facilities on the Customer's property at any time.

11.2 Access

FortisBC, through its authorized employees and agents, will have safe and ready access to its electrical facilities at all reasonable times for the purpose of reading meters and testing, installing, removing, repairing or replacing any equipment which is the property of FortisBC. If access is restricted, FortisBC will be supplied with keys to such locks if requested or, at FortisBC's option, a key holder box, where such locations are unattended during reasonable times.

In no case will FortisBC accept keys to private residential properties.

If safe and ready access to FortisBC's electrical facilities is denied or obstructed in any manner, including the presence of animals, and the Customer takes no action to remedy the problem upon being so advised, Service will be suspended and not reconnected until the problem is corrected. In cases where the Customer does not provide FortisBC with safe and ready access to the meter, FortisBC may install a remote meter. The Customer will be responsible for the cost of the remote meter and its installation as set out under the Meter Access Charge in Section 17 (Standard Charges).

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whenever the Customer has breached any agreement, including provisions of a Financing Agreement, with the Company, or failed to pay arrears within the specified time, fraudulently used the Service, tampered with the Company's equipment, committed similar actions, compromised the Company's Service to other Customers or if ordered by an authorized authority to suspend or terminate such Service. The cause of any Suspension must be corrected, and all applicable charges paid before Service will be resumed. Suspension of Service by the Company shall not operate as a cancellation of any contract with the Company, and shall not relieve any Customer of its obligations under these Terms and Conditions or the applicable rate schedule.

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Where FortisBC uses radio-frequency technology to remotely communicate with its meters or other infrastructure owned and maintained by FortisBC, the Customer is responsible for ensuring no device or obstruction is placed on or near FortisBC's equipment for the purpose of interfering, attenuating or degrading the signal.

If a FortisBC representative attends a Customer's Premises at the request of a Customer but on attending the Customer refuses access, or the FortisBC representative is unable to perform the requested work because the facilities required to be provided by the Customer for this purpose are found to be deficient a False Site Visit Charge per occurrence may be levied as set out in Section 17.3 (Miscellaneous Standard Charges).

11.3 Exception

Notwithstanding the provisions of Section 11.1 (Rights-of-Way) and Section 11.2 (Access), approval of the B.C. Utilities Commission will be required prior to any removal of plant constructed to serve industrial Customers supplied at 60 kV and above.

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12. CUSTOMER-OWNED GENERATION

12.1 Parallel Generation Facilities

A Customer may, at their own expense, install, connect and operate their own electrical generating facilities to its electrical circuit in parallel with FortisBC's electrical system provided that the manner of installation and operation of the facilities is satisfactory to FortisBC, and the facilities have the capacity to be immediately isolated from FortisBC's system in the event of disruption of Service from FortisBC.

Prior to the commencement of installation of any generating facilities, the Customer will provide to FortisBC full particulars of the facilities, and the proposed installation, and will permit FortisBC to inspect the installation. The Customer, at its own expense, will provide approved synchronizing equipment before connecting parallel generating facilities to the FortisBC electrical system.

The Customer's generating facilities will not be operated in parallel with FortisBC's electrical system until written approval has been received from FortisBC. The Customer will not modify its parallel facilities or the installation in any manner without first obtaining the written approval of FortisBC.

If at any time FortisBC's electrical system is adversely affected due to difficulties caused by the Customer's generating facilities, upon oral or written notice being given by FortisBC to a responsible employee of the Customer, the Customer will immediately discontinue parallel operation, and FortisBC may suspend Service until such time as the difficulties have been remedied to the satisfaction of FortisBC.

The Customer will be responsible for the proper installation, operation and maintenance of all protective and control equipment necessary to isolate the Customer's generating facilities from FortisBC's electrical system upon the occurrence of a fault on the Customer's generating facilities or FortisBC's electrical system. The Customer's protective equipment will not be modified in any manner and the settings thereto will not be changed without first obtaining written approval of FortisBC.

The Customer will notify FortisBC in advance each and every time that the Customer's generating facilities are to be connected to or intentionally disconnected from FortisBC's electrical system.

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During parallel operation of its generating facilities, the Customer will cooperate with FortisBC so as to maintain the voltage and the Power Factor of Electricity at the Point of Delivery within limits agreeable to FortisBC and as set out in Section 9.4 (Power Factor), and will take and use Electricity in a manner that does not adversely affect FortisBC's electrical system.

Notwithstanding any approval given by FortisBC, parallel operation of the Customer's generating facilities with FortisBC's electrical system will be entirely at the risk of the Customer, and the Customer will indemnify FortisBC and save it harmless from all injury, damage and loss and all actions, suits, claims, demands and expenses caused by or in any manner arising out of the operation of the Customer's generating facilities.

12.2 Standby Generation

A Customer may, at their own expense, install standby generation facilities to provide electrical Service in the event of a disruption of Service from FortisBC. Standby generation facilities will be installed so that they remain at all times electrically isolated from FortisBC's electrical system either directly or indirectly, and will be installed in such a way that it is not possible for the facilities to operate in parallel with FortisBC's electrical system.

The Customer's standby electrical generating facilities will not be operated without the prior inspection and written approval of FortisBC, and the facilities will not be modified thereafter without the written approval of FortisBC.

12.3 Electrical Inspection Authority

The Customer must obtain the approval of the appropriate electrical inspection authority before installation.

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13. GENERAL PROVISIONS

13.1 Notices

Any notice, direction or other instrument will be deemed to have been received on the following dates:

(a) if sent by electronic transmission, on the Business Day next following the date of transmission;

(b) if delivered, on the Business Day next following the date of delivery;

(c) if sent by registered mail, on the fifth Business Day following its mailing, provided that if there is at the time of mailing or within two Days thereafter a mail strike, slowdown, lockout or other labour dispute which might affect delivery, then any notice, direction or other instrument will only be deemed to be effective if delivered or sent by electronic transmission.

13.2 Conflicts

In case of conflict between these General Terms and Conditions and the Rate Schedules, the provisions of the Rate Schedules will prevail. Where there is a conflict between a contract and these General Terms and Conditions, the provisions of the contract will apply.

13.3 Force Majeure

If any Large Commercial Service Rate Schedule Customer is prevented from taking Electricity, except for emergency purposes, for a period in excess of five calendar Days by damage to its works from fire, explosion, the elements, sabotage, act of God or the Queen's enemies, or from insurrection, strike, or difficulties with workmen and invokes force majeure, FortisBC will not be bound to make Electricity available during the period of the interruption except for emergency purposes, and commencing on the sixth calendar Day of the interruption but for not more than 25 calendar Days, the Customer will, in lieu of the Demand Charge stipulated in the applicable Large Commercial Service Rate Schedule, pay a reduced Demand Charge for the period of the interruption, commencing on the sixth calendar Day of the interruption to a maximum of 25 calendar Days, derived from the Demand Charge rate multiplied by the maximum Demand recorded during that period of the interruption. The Customer will not be entitled to any adjustment in the monthly Demand Charge under this clause unless the Customer informs FortisBC in writing it is invoking this clause, and FortisBC will read the meters used for billing purposes at the end of the fifth Day of interruption and at the end of the period of interruption. The Customer will be prompt and diligent in removing the cause of the interruption (by restoring its works or such other action as may be necessary and as soon as the cause of the interruption

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is removed or ceases to exist FortisBC will without delay make Electricity available and the Customer will take and pay for the same in accordance with this Tariff.

The force majeure provisions of this Clause 11.4 will not apply in any Month in which FortisBC purchases Electricity from British Columbia Hydro and Power Authority, unless FortisBC and British Columbia Hydro and Power Authority agree to a force majeure provision, in which case the Customer will be given relief from the Demand Charge in accordance with that agreement.

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14. REPAYMENT OF ENERGY MANAGEMENT INCENTIVES

For those Customers supplied under Large Commercial Service or Wholesale Rate Schedules or Customers with a Contract Demand of 300 kVA or more, the unamortized balance of financial incentives paid to the Customer under Rate Schedule 90 will be remitted to FortisBC within 30 Days of billing, if:

(a) the operations at the Customer site are reduced by more than 50% for a continuous period of three Months or longer; or

(b) over 50% of the Electricity previously provided by FortisBC is replaced by another source including self-generation or another supplier.

In both cases the repayment will be prorated based on the amount of energy replaced compared to the amount of energy supplied by FortisBC in the year immediately preceding the Electricity replacement.

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15. ENERGY EFFICIENCY IMPROVEMENT FINANCING

Pursuant to section 17.1 of the *Clean Energy Act* and the *Improvement Financing Regulation*, for a two-year period beginning November 1, 2012 and ending January 1, 2015, FortisBC offers a Loan to eligible Customers located in the City of Kelowna and Regional District of Okanagan-Similkameen, excluding the City of Penticton and District of Summerland for energy efficiency improvements to an eligible Premises, or a part of an eligible Premises. The terms and conditions under which financing is offered are contained in Electric Tariff Rate Schedule 91.

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16. EXTENSIONS

16.1 Ownership and Maintenance

FortisBC will assume ownership and maintenance of an Extension on public or private property upon connection of the Extension to FortisBC's distribution system.

16.2 Application Requirements

FortisBC will commence construction of an Extension or authorize the connection or disconnection of an Extension constructed by a FortisBC pre-approved contractor once the following conditions have been met:

(a) The applicant for an Extension has completed a contract for Service as required under Section 2 (Application for Service) and any other required documentation;

(b) The applicant has obtained all necessary easements, permits, or licences of occupation;

(c) Where applicable, construction of the new building has advanced to the point where completion seems assured, or the applicant has provided adequate security for the amount of FortisBC's investment; and

(d) the applicant has paid to FortisBC the full estimated CPC less any amount financed by FortisBC and less any amount agreed to by FortisBC pursuant to Section 16.3 (Customer Portion of Costs).

16.3 Customer Portion of Costs

16.3.1 FortisBC Contribution

FortisBC will contribute towards an Extension as follows, multiplied by the number of Customers to be served from the Extension:

Rate Schedule	Maximum FortisBC Contribution
Rate Schedule 1, 2A, 3A	$2,634
Rate Schedule 20, 21	$279 per kW
Rate Schedule 30	$121 per kW
Rate Schedule 50 (Type I, Type II)	$28.15 per fixture
Rate Schedule 60, 61	$3,543

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The Applicant will pay the Customer Portion of Costs (CPC). The CPC is the estimated cost to construct the Extension less the FortisBC Contribution towards the Extension, and does not include any applicable connection charges as specified in Section 17 (Standard Charges). The CPC will be paid either in cash or, with FortisBC's agreement, wholly or partly in kind.

16.3.2 Refund of Customer Portion of Costs

FortisBC will have the right to connect additional Customers to an Extension. Additional Customers that take Service from an Extension within five Years of the connection of the Extension to FortisBC's distribution system will pay a share of the Extension Cost (less the FortisBC Contribution towards the Extension), without interest, in proportion to that part of the Extension that is used to provide Service and in proportion to the number of original Customers taking Service from the Extension.

No share of the Extension Cost will be paid where:

(a) the contribution would be less than $200.00 per Customer connected to the Extension; or

(b) more than five Years have passed from the date the Extension was connected to FortisBC's distribution system to the date of the connection of the additional Customer to the Extension.

A refund of the Extension Cost that has been received from an additional Customer connecting to the Extension will be made existing Customers on that Extension.

16.3.3 Financing

FortisBC financing is available to applicants for an Extension on approval of credit. The CPC will be financed based on FortisBC's weighted average cost of capital as approved by the British Columbia Utilities Commission. A downpayment of 20% of the CPC is required from each applicant. Financing is available for one to five Year terms for extensions costing over $2,000. FortisBC will finance a maximum of $10,000 per applicant.

16.3.4 Special Contracts

An applicant for an Extension may be required to make a contribution in addition to the CPC in the following circumstances:

(a) Where additional investment is required in order to upgrade or reinforce existing facilities or install new facilities to provide Service at a phase and voltage not presently available;

(b) For Large Commercial Service and Industrial Applicants, where installation and upgrading of substation and transmission facilities may be required; or

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(c) For temporary or standby Service, where the Applicant may also be required to pay the cost of removal of the facilities.

In any of the the above circumstances, FortisBC may request the applicant for an Extension to enter into a special contract arrangement. The special contract may require the applicant to pay for Extension Costs and upgrades or reinforcements of existing facilities, and to pay for any replacements of the Extension that may be required.

16.4 Design and Construction Requirements

Extensions will normally be constructed overhead, but may be constructed underground where such construction is in accordance with FortisBC's distribution system plans or other constraints exist that require underground systems.

Extensions will be designed and constructed in accordance with FortisBC's distribution construction standards and material specifications.

16.5 Designing and Estimating

An applicant for an Extension may select FortisBC or a FortisBC pre-approved contractor to design and/or construct the Extension.

Where an applicant selects FortisBC to design and/or construct the Extension:

(a) Upon receipt of a request for Service requiring an Extension, FortisBC will engineer and design the Extension (Design Package), and provide a quote of the Extension cost (Estimate Package);

(b) The cost of preparing the Design Package, including the cost of any revisions to the Design Package that are requested by the applicant, will be borne by the applicant and will be paid upon receipt of the Design Package;

(c) Prior to the release of the Design Package and the Estimate Package, the Applicant may be required to sign a contract that includes terms and conditions relating to the construction of the Extension.

(d) FortisBC will construct the Extension at the cost quoted in the Estimate Package.

Where an applicant selects a FortisBC pre-approved contractor to design and/or construct the Extension:

(a) The Design Package will be engineered and designed to FortisBC standards, and FortisBC will provide an Estimate Package for FortisBC's costs;

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(b) Prior to the connection of the Extension to FortisBC's distribution system, the applicant will pay to FortisBC all additional costs, estimated in advance by FortisBC and provided to the applicant in the Estimate Package, incurred for designing, engineering, surveying, obtaining permits, connecting to FortisBC's distribution system, and inspecting the Extension;

(c) FortisBC, in its sole discretion, may survey, at the cost of the applicant, Extensions designed and/or constructed by a FortisBC pre-approved contractor prior to connecting the Extension to FortisBC's distribution system.

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16.6 Delay in Construction

Where Customer actions cause construction to be delayed by a period of 6 Months or greater after receipt of the CPC, FortisBC reserves the right to re-quote the CPC using current pricing, excluding any material(s) already purchased. Any additional costs must be paid by the Customer to FortisBC prior to the commencement of construction. Any resulting credit will be promptly refunded by FortisBC to the Customer.

16.7 Limitation on Work Done by FortisBC Pre-approved Contractors

A FortisBC pre-approved contractor may not work on any of FortisBC's electrical facilities, and FortisBC will make all connections to or disconnections from FortisBC's distribution system.

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16.8 Easements and Right of Way Clearing

An applicant for an Extension will provide an easement for the Extension, including an easement for vehicle access to the Extension, that is acceptable to FortisBC. For Extensions to be constructed by FortisBC, such easement will be provided prior to the construction of the Extension. For all other Extensions, such easement will be provided prior to the connection of the Extension to FortisBC's distribution system.

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The applicant will be responsible for all right of way clearing costs required for the construction of an Extension.

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The Applicant will ensure that all right of way clearing is performed in accordance with FortisBC's distribution construction standards.

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17. STANDARD CHARGES SCHEDULE

17.1 Installation of New/Upgraded Services

The minimum charge for the installation of a new or upgrading of an existing Service, including one meter, is as follows:

Overhead – Single Phase – 200 Amps or less	$739
Underground – Single Phase – 200 Amps or less	$804

For all other Service connections and a meter, the applicant will pay the Customer Portion of Costs of the Service connection as per Section 4.5 (Customer Contributions).

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17.2 Connection Charges

Meter connection, or manual reconnection of a meter after disconnection for violation of the General Terms and Conditions in this Tariff, or Meter Test

Performed during regular working hours	$135
Performed during overtime hours	$224
Performed during callout hours	$462
Each additional Meter connection for one Customer at the same time at one location	$34
Remote reconnection of a meter after disconnection for violation of the General Terms and Conditions in this Tariff	$13
Disconnection and reconnection of meter	$271
Relocation of existing Service requiring a Service drop change on the same building during regular working hours	$902

17.3 Miscellaneous Standard Charges

Account Setup or Transfer	$13
Return Payment Charge	$13
Meter Access Charge – Single Phase Remote Meter	$206
Meter Access Charge – Poly Phase Remote Meter	$419
False Site Visit Charge	$246
Temporary to Permanent Service Charge	$267
Salvage of Temporary Service Charge	$267

17.4 Custom Work

FortisBC may recover the full cost of the following custom work:

(a) At the Customer's request, when a special trip is necessary to inspect a Service due to an outage and the fault is found to be beyond the Point of Delivery, FortisBC will be reimbursed for the full cost;

(b) Installation of facilities beyond those considered necessary by FortisBC in order to provide Service and not provided for elsewhere in FortisBC's tariff;

(c) Replacement or repair of facilities damaged by causes other than reasonable wear and tear;

(d) At the Customer's request, relocation of the Service to permit tree trimming, construction, etc., where recovery of the costs are not provided for in the standard charges above.

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18. RADIO-OFF ADVANCED METER OPTION

18.1 Applicable To

A FortisBC Customer with a FortisBC-installed meter with integrated wireless transmit functions enabled, or a Customer scheduled by FortisBC to receive a meter with integrated wireless transmit functions enabled will apply for a Radio-off AMI Meter.

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18.2 Application Requirements

Radio-off Customers will apply to FortisBC for a Radio-off AMI Meter consistent with the process required for a standard Application for Service as set out in Section 2 (Application for Service) of FortisBC's Electric Tariff General Terms and Conditions and will be provided with a meter that has the integrated wireless transmit functions disabled.

18.3 Conditions of Service

Radio-off Customers will pay the charges as set out in Section 18.4 (Radio-off Option Standard Charges). Failure to pay these charges will be subject to standard collection procedures and may result in the Discontinuance of Service. The Per-premise set up fee will be charged on the first bill after the Radio-off AMI Meter is installed, and the Per-Read fees will be charged on every subsequent bill.

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If a Radio-off Customer elects to stop using the Radio-off AMI Meter Option, FortisBC will obtain a final manual meter read prior to enabling the integrated wireless transmit functions of the meter. The Radio-off Customer will incur one final Per-Read fee for this service.

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18.4 Radio-off Option Standard Charges

Radio-off Customers will be charged the following by FortisBC for the Radio-off AMI Meter Option:

Per-Premise Setup Fee	$88
Per-Read Fee	$25

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Customer: Customers that have a Radio-off AMI Meter installed at their Customer Premises.¶
Radio-off AMI¶
Meter: An advanced meter with integrated wireless transmit functions disabled.¶
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RATE SCHEDULE 1 - RESIDENTIAL SERVICE

APPLICABLE: To residential use including service to incidental motors of 5 HP or less.

BIMONTHLY RATE: First 1600 kW.h @ 10.394¢ per kW.h

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Additional kW.h @ 14.915¢ per kW.h

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CUSTOMER CHARGE: $33.16 per two Month period

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OVERDUE ACCOUNTS: A late payment charge of 1 1/2 % will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

NOTE: For the purposes of Monthly billing the Customer Charge will be prorated on a Monthly basis and the threshold will be 800 kW.h per Month.

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PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 2 A - RESIDENTIAL SERVICE - TIME OF USE

APPLICABLE: To Residential use including service to incidental motors of 5 HP or less. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	22.435
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	11.869
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9.280

plus:

CUSTOMER CHARGE: $37.39 per two Month period

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

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RATE SCHEDULE 3 A - EXEMPT RESIDENTIAL SERVICE

APPLICABLE: To residential use including service to incidental motors of 5 HP or less. For residential service and use exempted from Rate Schedule 1, including:

1. Farm Customers that qualify for Residential Service as set out in FortisBC's Electric Tariff General Terms and Conditions Section 6.3.3 (Farms) and subject to the SPECIAL CONDITIONS below.

BIMONTHLY RATE: All kW.h @ 11.749¢ per kW.h

plus:

CUSTOMER CHARGE: $37.39 per two Month period

OVERDUE ACCOUNTS: A late payment charge of 1 1/2 % will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

NOTE: For the purposes of Monthly billing the Customer Charge will be prorated on a Monthly basis.

SPECIAL CONDITIONS:

A. Farm Customers who elect to take service under this Rate Schedule must provide to FortisBC a copy of the most recent year's BC Assessment notice, or other acceptable documentation to FortisBC, identifying the subject property as having a farm classification.

B. Schedule 3 A – Exempt Residential Service for farm Customers will remain in effect until such time as a decision is rendered on the next FortisBC rate design application.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

Deleted: RATE SCHEDULE 3 - EXEMPT RESIDENTIAL SERVICE¶
APPLICABLE: To residential use including service to incidental motors of 5 HP or less. For residential service and use exempted from Rate Schedule 1, including:¶
1. Customers enrolled in FortisBC's Residential Conservation Rate (RCR) control group. A Customer who ceases to be enrolled in the RCR control group shallwill revert to service under Rate Schedule 1.¶
BIMONTHLY ¶
RATE: Customer Charge $37.39 per period¶
All kW.h @ 11.749¢ per kW.h¶
OVERDUE¶
ACCOUNTS: A late payment charge of 1 1/2 % will be assessed each month(compounded monthly 19.56% per annum) on all outstandingbalances not paid by the due date.¶
NOTE: For the purposes of monthly billing the cCustomer cCharge shallwill be prorated on a monthly basis.¶
SPECIAL ¶
CONDITIONS: A. FortisBC will periodically credit to the RCR control group ¶
subscriber's account any positive difference between the total dollar amount billed to the subscriber under the Schedule 3 – Exempt Residential Service tariff and the total dollar amount derived by rendering bills on the same metered usage using the rates in Schedule 1 – Residential Service for the applicable period, for the duration of the RCR control group.¶
PERMANENT RATE ¶
ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.¶
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RATE SCHEDULE 20 - SMALL COMMERCIAL SERVICE

APPLICABLE: To Commercial Customers whose electrical Demand is generally not more than 40 kW and can be supplied through one meter. Where there is more than one service to the same location and they are of the same voltage and phase classification and they were connected prior to January 5, 1977, the electrical energy and Demands registered for such services will be combined and billed at this rate.

BI-MONTHLY RATE: All kW.h @ 10.000¢ per kW.h

plus:

CUSTOMER CHARGE: $46.00 per two Month period

DELIVERY AND METERING VOLTAGE DISCOUNTS: The above rate applies to power service when taken at FortisBC's standard secondary voltage. A discount of 1 1/2% will be applied to the above rate if the electric service is metered at a primary distribution voltage.

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

NOTE: For the purposes of Monthly billing the Customer Charge will be prorated on a Monthly basis.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

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RATE SCHEDULE 21 - COMMERCIAL SERVICE

APPLICABLE: To Commercial Customers whose electrical Demand is generally greater than 40 kW but less than 500 kW and can be supplied through one meter. Where there is more than one service to the same location and they are of the same voltage and phase classification and they were connected prior to January 5, 1977, the electrical energy and Demands registered for such services will be combined and billed at this rate.

MONTHLY RATE:

A Demand Charge of:

$11.35 per kW of "Billing Demand" above 40 kW

plus:

An Energy Charge of:

All kW.h 6.875¢ per kW.h

plus:

CUSTOMER CHARGE: $54.00 per Month

"Billing Demand"

The greatest of:

i. twenty-five per cent (25%) of the Contract Demand, or

ii. the maximum Demand in kW for the current billing Month, or

iii. seventy-five per cent (75%) of the maximum Demand in kW registered during the previous eleven Month period.

DELIVERY AND METERING VOLTAGE DISCOUNTS: The above rate applies to power service when taken at FortisBC's standard secondary voltage.

(a) A discount of 1 1/2% will be applied to the above rate if the electric service is metered at a primary distribution voltage.

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RATE SCHEDULE 21 - COMMERCIAL SERVICE (Cont'd)

(b) A discount of 28.0¢ per kW of Billing Demand will be applied to the above rate if the Customer supplies the transformation from the primary to the secondary voltage.

(c) If a Customer is entitled to both of the above discounts, the discount applicable to the metering at a primary voltage is to be applied first.

POWER FACTOR: If at FortisBC's option, the Demand is measured in kVA instead of kW then;

40 kW will become 45 kVA
28.0¢ per kW will become 25.0¢ per kVA
$11.35 per kW will become $10.22 per kVA
where used in this schedule.

BILLING CODES: The following letter designations may appear on Customer's bills:

"A" – Demand measured in kW, FortisBC owned transformation from primary to secondary distribution voltage, metering at secondary distribution voltage

"B" – Demand measured in kVA, FortisBC owned transformation from primary to secondary distribution voltage, metering at secondary distribution voltage

"C" – Demand measured in kW, Customer owned transformation from primary to secondary distribution voltage, metering at primary distribution voltage

"D" – Demand measured in kVA, Customer owned transformation from primary to secondary distribution voltage, metering at primary distribution voltage

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

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RATE SCHEDULE 22 A - COMMERCIAL SERVICE – SECONDARY – TIME OF USE

APPLICABLE: To Commercial Customers whose electrical Demand is less than 500 kW and is supplied at a secondary distribution voltage through one meter. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

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RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	20.675
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	10.109
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	7.520

plus:

CUSTOMER CHARGE: $23.00 per Month

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BILLING: FortisBC may, at its option, bill this rate bimonthly in which case the Customer Charge will be doubled.

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OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 23 A - COMMERCIAL SERVICE - PRIMARY - TIME OF USE

APPLICABLE: To Commercial Customers whose electrical Demand is less than 500 kW and is supplied at a primary distribution voltage through one meter. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

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RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	19.795
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	9.229
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	6.640

plus:

CUSTOMER CHARGE: $54.00 per Month

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OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 30 - LARGE COMMERCIAL SERVICE - PRIMARY

APPLICABLE: To power service to Customers for a contract Demand of 500 kVA or more, subject to written agreement.

MONTHLY RATE: A Demand Charge of:

$9.19 per kVA of Billing Demand

plus:

An Energy Charge of:

All kW.h @ 5.571¢ per kW.h

plus:

CUSTOMER CHARGE: $945.04 per Month

"Billing Demand"

The greatest of:

i. twenty-five percent (25%) of the Contract Demand, or

ii. the maximum Demand in kVA for the current billing Month, or

iii. seventy-five percent (75%) of the maximum Demand in kVA registered during the previous eleven Month period.

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RATE SCHEDULE 30 - LARGE COMMERCIAL SERVICE - PRIMARY (Cont'd)

DELIVERY AND METERING VOLTAGE DISCOUNTS: The above rate applies to power service when taken at FortisBC's standard primary distribution voltage available in the area.

(a) A discount of 1 1/2% will be applied to the above rate if the electric service is metered at a transmission line voltage.

(b) A discount of $5.26 per kVA of billing Demand will be applied to the above rate if the Customer supplies the transformation from the transmission line voltage to the primary distribution voltage.

(c) If a Customer is entitled to both of the above discounts, the discount applicable to the metering at a transmission line voltage is to be applied first.

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

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RATE SCHEDULE 31 - LARGE COMMERCIAL SERVICE - TRANSMISSION

AVAILABLE: In all areas served by FortisBC for supply at 60 hertz, three phase with a nominal potential of 60,000 volts or higher as available.

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APPLICABLE: Applicable to industrial Customers with loads of 5,000 kVA or more, subject to written agreement.

MONTHLY RATE: A Wires Charge of:

$4.93 per kVA of Billing Demand; plus:

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A Power Supply Charge of:

$3.45 per kVA of maximum Demand in current billing Month; plus:

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An Energy Charge of:

All kW.h @ 5.367¢ per kW.h

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CUSTOMER CHARGE: $3,195.00 per Month

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"Billing Demand"

The greatest of:

i. eighty percent (80%) of the Contract Demand, or

ii. The maximum Demand in kVA for the current billing Month; or

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iii. eighty percent (80%) of the maximum Demand in kVA recorded during the previous eleven Month period.

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Plus, for Customers with a Stand-by Billing Demand under Rate Schedule 37 (except when Rate Schedule 37, Special Provision 7 applies);

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Stand-by Billing Demand.

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 32 - LARGE COMMERCIAL SERVICE - PRIMARY - TIME OF USE

APPLICABLE: To power service to Customers for a contract Demand of 500 kVA or more, taking service at a standard primary distribution voltage, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service

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RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	19.285
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	8.719
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	6.130

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plus:

CUSTOMER CHARGE: $3,195.00 per Month

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OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 33 - LARGE COMMERCIAL SERVICE - TRANSMISSION - TIME OF USE

APPLICABLE: In all areas served by FortisBC for supply at 60 hertz, three phase with a nominal potential of 60,000 volts or higher as available. Applicable to industrial Customers with loads of 5,000 kVA or more, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

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RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	18.395
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	7.829
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	5.240

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CUSTOMER CHARGE: $3,195.00 per Month

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OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 37 - LARGE COMMERCIAL SERVICE- STAND-BY SERVICE

AVAILABILITY: Stand-by Service is a Back-Up and Maintenance Service intended to provide the Customer with a firm supply of electric power and energy when the Customer's generating facilities are not in operation or are operating at less than full rated capability.

Stand-by Service is available only to those Customers that normally supply all or some portion of load from self-generation and is strictly for the continued operation of Customer facilities at times when the Customer-owned generation is unavailable.

Stand-by Service cannot be used by the Customer in the fulfillment of any power sales obligation.

Stand-by Service in only available to a Customer contracted to receive service under Rate Schedule 31 (Rate Schedule 31).

Rate Schedule 31 Contract Demand is the Customer's Contract Demand expressed in kilovolt Amperes (kVA) and specified in the General Service Agreement (GSA) between FortisBC and the Customer. If the Customer and FortisBC cannot come to an agreement, the Rate Schedule 31 Contract Demand will be set by the British Columbia Utilities Commission.

Service taken up to a Customer's Rate Schedule 31 Contract Demand is not considered to occur within a Stand-by Period.

Net Metering Customers are not eligible for Stand by Service.

DEFINITIONS:

In this Schedule,

1. "Customer" has the meaning provided in FortisBC's Electric Tariff B.C.U.C. No. 2, Section 1 (Definitions).
2. "BCUC" means the British Columbia Utilities Commission.
3. "Maintenance Service" is provided during a FortisBC-approved scheduled outage for maintenance or downtime of the on-site generation.

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RATE SCHEDULE 37 – LARGE COMMERCIAL SERVICE - STAND-BY SERVICE (Cont'd)

DEFINITIONS: (Cont'd)

4. "Back-Up Service" is an on-demand service required during unscheduled outages of the self-generation, ensuring that utility capacity is available for a Customer to call on to meet the Customer's load.

5. "Stand-by Period" is the total time during which the Customer is taking service under this Rate Schedule. Service taken up to a Customer's Rate Schedule 31 Contract Demand is not considered to occur within a Stand-by Period.

6. "Stand-by Penalty Period" occurs under the conditions identified in Special Provision 7.

7. "Stand-by Demand Limit (SBDL)", expressed in kVA, is required to be established under this Schedule for billing purposes. The SBDL for a Customer using this Schedule will set the maximum demand of service that can be supplied to the Customer under this Schedule. SBDL is to be agreed to between the Customer and FortisBC and is specified in the GSA between FortisBC and the Customer. If the Customer and FortisBC cannot come to an agreement, the SBDL will be set by the BCUC.

8. "Maximum Level of Stand-by Service", in any Hour, or metered portion thereof, capacity in kVA will be available to a maximum of the difference between the SBDL and the Customer's generation in that Hour in kVA.

SERVICES:

Part A: Maintenance Service

Maintenance Service is supplied during schedule outages of the Customer's generation for the purpose of maintenance of the generation facility. The Customer must schedule maintenance power with FortisBC not less than 30 Days prior to its use. Maintenance power service will be limited to not more than six occurrences and not more than sixty (60) total Days during a calendar Year.

Maintenance Service is terminated upon notification from the Customer that the event is over.

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RATE SCHEDULE 37 – LARGE COMMERCIAL SERVICE - STAND-BY SERVICE (Cont'd)

SERVICES: (Cont'd)

Part B: Back-Up Service

Back-Up Service is supplied to replace energy generated by a Customer's own equipment when that equipment is not in service, except during periods of maintenance. Notification for the use of Back-Up Service must be provided as per Special Provision 4 and is limited to 876 Hours per calendar Year.

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The provision of Back-Up Service will be considered to be automatically terminated if the Customer has not consumed FortisBC's electricity for 8 continuous Hours, after which time the Customer will be required to provide separate notice for a new instance of Back-Up Service.

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CHARGES:

Monthly Rate: A Notification Fee of $200.00 per use; plus

Rate Schedule 37 Energy Charge:

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An Hourly Stand-By Energy charge determined by:

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(i) The Hourly Powerdex Mid-Columbia (Mid-C) per kWh price for the Hour in which the Stand-by Energy is taken by the Customer. In Hours in which the Mid-C price is negative, a value of $0.00 will be used; and

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(ii) System losses as per Rate Schedule 109; and

(iii) Hourly transmission charges from the Mid-C hub to the border of $0.0040 per kWh; and

(iv) Administrative premium of 10 percent.

The Hourly charge is calculated as:

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Rate Schedule 37 Energy Charges = [(Stand-by Energy x (1+ loss rate %)) x (Mid-C + 0.0040)] x 1.10

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Where "Stand-by Energy" refers to the energy delivered during the Stand-by Period.

RATE SCHEDULE 37 – LARGE COMMERCIAL SERVICE - STAND-BY SERVICE (Cont'd)

CHARGES: (Cont'd)

Scenarios:

a. In any Hour all energy delivered up to or below the Rate Schedule 31 Contract Demand is not Stand-by Energy and is billed under Rate Schedule 31.

b. In any Hour, or metered portion thereof, if a Customer's demand exceeds the Rate Schedule 31 Contract Demand, but the demand in excess of the Rate Schedule 31 Contract Demand is less than the Maximum Level of Stand-by Service then:

   Stand-by Energy = total consumption – Rate Schedule 31 Contract Demand consumption

c. In any Hour, or metered portion thereof, if a Customer's demand exceeds the Rate Schedule 31 Contract Demand plus the Maximum Level of Stand-by Service allowed, service will be charge in accordance with Special Provision 7.

In any billing period, regardless of the above Scenario under which consumption charges are determined, total consumption will be equal to the total metered consumption recorded at the Customer's premise.

SPECIAL PROVISIONS:

1. Stand-by Billing Demand (SBBD) – Billing under this Rate Schedule requires the establishment of a SBBD, expressed in kVA. SBBD for a Customer using this Rate Schedule will be set at an amount between zero and 100 percent of the Customer's SBDL and is to be used in the determination of the Wires Charge in Rate Schedule 31. The SBBD is to be agreed to between the Customer and FortisBC and is specified in the GSA between FortisBC and the Customer. If the Customer and FortisBC cannot come to an agreement, the SBBD will be set by the BCUC.

2. Billing Demand in the underlying rate – The maximum demand recorded during a Stand-by Period will not be used in the calculation of Billing Demand in Rate Schedule 31.

3. Power Supply Demand Charge – The peak demand measured during a Stand-by Period will not be used in the calculation of demand charges in Rate Schedule 31.

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RATE SCHEDULE 37 – LARGE COMMERCIAL SERVICE - STAND-BY SERVICE (Cont'd)

SPECIAL PROVISIONS: (Cont'd)

4. Back-Up Notification – The Customer must information FortisBC within 30 minutes of taking energy under the Back-Up provisions of this Schedule and inform FortisBC of the anticipated time that the generator will return to normal operations. If the Customer's generator is not available at the anticipated time, further notice including an updated anticipated time that the generator will return to normal operations must be provided.

5. Metering – The Customer must have FortisBC approved interval metering and meter communications in place prior to initiation of service under this Rate Schedule. FortisBC requires metering that measures the net quantity and direction of flow at the point of interconnection between the Customer and FortisBC and total generator output.

6. Required Equipment – The Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which FortisBC's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and the necessary wiring on both sides of the transformers. All transformers, equipment and wiring will be of types and characteristics approved by FortisBC and their installation, operation and maintenance will be subject to inspection and approval by FortisBC.

7. Stand-by Penalty Period - In any Hour, or metered portion thereof, if a Customer's demand exceeds the Rate Schedule 31 Contract Demand plus the Maximum Level of Stand-by Service allowed or a Customer's demand exceeds the Rate Schedule 31 Contract Demand and the Customer is not eligible for either Maintenance or Back-Up Service due to the restrictions under this Rate Schedule service above the Customer's Rate Schedule 31 Contract Demand will be considered a Stand-by Period subject to the following penalty:

   In a Stand-By Penalty Period Hour:

   a. Rate Schedule 37 Energy Charge (i) will be replaced with:

      The Hourly per kWh price for the Hour in which the Stand-by Energy is taken by the Customer is the greater of:

      i. $1,000

      ii. $50/MWh calculated as:

         [(Stand-by Energy x (1 + loss rate %)) x (0.05 + 0.0040)] x 1.10

      iii. 150 percent of the Energy Charge that would have resulted under the calculation of Rate Schedule 37 Energy Charge (i) in this Rate Schedule calculated as:

         [(Stand-by Energy x (1 + loss rate %)) x ((Mid-C x 1.5) + 0.0040)] x 1.10

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RATE SCHEDULE 37 – LARGE COMMERCIAL SERVICE - STAND-BY SERVICE (Cont'd)

SPECIAL PROVISIONS: (Cont'd)

b. Special Provision 2 will not apply. The maximum demand recorded in the Hour during a Stand-by Penalty Period will be used in the current billing period's calculation of Billing Demand in Rate Schedule 31 but will not set a ratchet that will be used in the calculation of Billing Demand in Rate Schedule 31 in future billing periods.

When Back-Up Service is taken in excess of the calendar Year Hourly limit or when Special Provision 4 has been violated FortisBC will waive the penalty under the following circumstances:

a. An extreme or unusual circumstance as identified in the force majeure provision in FortisBC's approved tariff, Section 12 limits the self-generation of the Customer; or

b. A temporary reduction in Customer generation, as a response to a system issue on FortisBC's system, which takes the Customer's generation off-line.

Where service is taken during a Stand-by Period, but is taken under the circumstances described in items a. and b. above, and is not taken as described in Scenario c. of the Energy Charges section of this Schedule, the duration of the Stand-by Period involved will not be counted toward the limitation on Stand-by Service of 876 Hours per calendar Year.

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RATE SCHEDULE 40 - WHOLESALE SERVICE - PRIMARY

AVAILABLE: In Grand Forks, Kelowna, Penticton, Princeton, Summerland, Lardeau and Yahk.

APPLICABLE: To service for resale, subject to written agreement.

MONTHLY RATE: A Wires Charge of:

$8.98 per kVA of Billing Demand

plus:

A Power Supply Charge of:

$4.82 per kVA of maximum Demand in current billing Month

plus:

An Energy Charge of:

All kW.h @ 5.441¢ per kW.h

CUSTOMER CHARGE: $2,645.03 per Point of Delivery per Month

"Billing Demand"

The greatest of:

i. eighty percent (80%) of the Contract Demand, or
ii. the maximum Demand in kVA for the current billing Month, or
iii. eighty percent (80%) of the maximum Demand in kVA registered during the previous eleven Month period.

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RATE SCHEDULE 40 - WHOLESALE SERVICE - PRIMARY (Cont'd)

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

DELIVERY VOLTAGE DISCOUNT: The above rate applies to power service when taken at FortisBC's standard primary voltage.

A discount of 0.770¢ per kW.h will be applied to the Energy Charge and a discount of $2.64 per kVA will be applied to the Power Supply Charge if the Customer supplies the transformation from the transmission line voltage to the primary distribution voltage.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 41 - WHOLESALE SERVICE - TRANSMISSION

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

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

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MONTHLY RATE: A Wires Charge of:

$6.34 per kVA of Billing Demand

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plus:

A Power Supply Charge of:

$4.77 per kVA of maximum Demand in current billing Month

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plus:

An Energy Charge of:

All kW.h @ 4.501¢ per kW.h

CUSTOMER CHARGE: $5,974.48 per Month

"Billing Demand"

The greatest of:

i. eighty percent (80%) of the Contract Demand, or

ii. the maximum Demand in kVA for the current billing Month, or

Deleted: month

iii. eighty percent (80%) of the maximum Demand in kVA registered during the previous eleven Month period.

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RATE SCHEDULE 41 - WHOLESALE SERVICE – TRANSMISSION (Cont'd)

OVERDUE
ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

RATE FOR
EMERGENCY
PURPOSES: The additional Demand resulting from emergency or shutdown service (Emergency Demand) will be excluded in determining the application of Item (c) in the calculation of the Billing Demand, provided the City of Nelson requests that the Demand meter be read by FortisBC immediately before and after the emergency or as soon as practical at the commencement of the emergency period. The amount of Emergency Demand will be determined from the meter readings and the best information available. The City of Nelson will compensate FortisBC for any higher Demand charges resulting from the Emergency Demand.

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PERMANENT RATE
ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 42 - WHOLESALE SERVICE - PRIMARY -TIME OF USE

APPLICABLE: To power Service to Grand Forks, Kelowna, Penticton, Summerland, Lardeau, and Yahk, at a Primary Voltage for resale, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by FortisBC, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive Months after commencement of Service.

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RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	19.995
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	9.429
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	6.840

plus:

CUSTOMER CHARGE: $2,645.03 per Month per Point of Delivery

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OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 43 - WHOLESALE SERVICE - TRANSMISSION - TIME OF USE

APPLICABLE: To supplementary power service to the City of Nelson, subject to written agreement. At suitable City of Nelson interconnections with FortisBC's 63kV system. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

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RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	19.185
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	8.619
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	6.030

plus:

CUSTOMER CHARGE: $895.79 per Month

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OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 50 - LIGHTING - ALL AREAS

APPLICABLE: To lighting applications where the Customer will contract for service for a term of one Year. FortisBC will supply service for lighting from dusk to dawn daily.

All lighting equipment installed on and after the effective date of this Schedule will be FortisBC approved and conform to all relevant FortisBC design and installation standards and requirements, and be suitable to accept electrical service at FortisBC's available secondary voltage. Other requirements may be supplied under special contract.

This Schedule is not available for equipment other than FortisBC approved lighting fixtures.

TYPES OF SERVICE:

1. Customer-Owned and Customer-Maintained

Type I - For a Customer-owned street lighting fixture or lighting system where the Customer owns and maintains at its own expense the light standards if any, lighting fixtures and all auxiliary equipment.

Electricity at 120/240 volts single phase is supplied by FortisBC at a single point of delivery for each separate Customer system. Multiple light systems will be provided service at a single point of delivery wherever practical. The Customer will supply transformers for other than 120/240 volt single phase supply.

Type I will apply only if the Customer system can be operated and maintained, beyond the point of supply of electricity, independently of FortisBC's system. The installed cost of devices necessary for independent operation will be paid by

the Customer. Where Customer owned lighting fixtures are on FortisBC owned poles maintenance work will only be performed by parties qualified to do the work, and authorised by FortisBC. FortisBC reserves the right to refuse Type I service for any reason.

2. Customer-Owned and FortisBC-Maintained

Type II - Customer-owned street lighting fixtures installed on existing FortisBC poles at the Customer's expense with all maintenance to be performed by FortisBC at costs described below.

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RATE SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

TYPES OF SERVICE: (Cont'd)

3. FortisBC-Owned, FortisBC-Installed and Maintained

Type III - For FortisBC-owned street lighting fixtures on existing FortisBC-owned poles where FortisBC performs all maintenance. Facilities provided by FortisBC, including fixtures, lamp, control relay, support bracket, and conductor and energy for operation thereof are owned by FortisBC.

TERMS AND CONDITIONS:

Installation

Type II lighting fixtures of design and specifications approved by FortisBC for installation on FortisBC-owned poles will be installed by FortisBC at the Customer's expense. There will be no charge to the Customer for the use of existing FortisBC-owned poles as standards for mounting of fixtures other than as provided for in this section.

FortisBC will provide to the Customer on request, lighting fixtures and standards, where required, of FortisBC approved design and specifications at its cost plus overheads and handling costs as described in the Cost Recovery section below. For Type III fixtures FortisBC will provide one span of duplex of not more than 30 metres.

Extension of Service

Extensions of service will be provided under the terms of FortisBC's Extension Policy.

Relocation

At the Customer's request, the location of a light may be changed provided the Customer pays for the cost of removal and reinstallation, including cost of extension of service if applicable, with costs recovered as described below.

Other Equipment

Equipment other than lighting fixtures is not permitted on FortisBC-owned poles except with FortisBC's written consent.

Dimmable Lighting

Dimmable service is only available for Type I and Type II lighting service where the Customer has five or more fixtures. For Type II service the Customer will provide to FortisBC an adequate supply of replacement parts at no cost to FortisBC.

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RATE SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

TERMS AND CONDITIONS:

Dimmable Lighting (Cont'd)

For each dimmable fixture, the Customer will provide FortisBC with a schedule showing the rated wattage of the lamp and auxiliary devices together with a schedule showing the wattage consumed each Hour and the resultant annual kW.h consumption. FortisBC will bill one-twelfth of the annual consumption each Month. The Customer will provide timely notification of any changes of operation, number and/or wattage of fixtures on June 1 of each year. The Customer will provide access to the dimmable fixtures upon reasonable notice by FortisBC to the Customer.

Maintenance of Type III Lights

Maintenance of Type III lighting fixtures will be performed by FortisBC, the cost of which is provided for in the "Monthly Rate" of this Schedule. Such work will be undertaken by FortisBC during regular working Hours and FortisBC will be allowed ten working Days subsequent to notification by the Customer for performance of such maintenance. Cleaning of the glassware will be carried out only when the lamp is replaced.

The Customer will be responsible for any wilful damage to FortisBC's equipment.

Maintenance of Type II Lights

The Customer will pay maintenance and capital costs, including the cost of installation, maintenance of underground supply, and relocation, on an as spent basis. Customers will inform FortisBC in writing of the location of any lighting fixture requiring maintenance and the time in which the maintenance must be performed. FortisBC will bill the Customer for all costs incurred including the following overheads:

Cost Recovery

Labour Loading

On labour costs excluding overtime	74% of labour rate

Material Loading

Inventory – Material Handling	10% of cost

Loading rates may be adjusted from time to time as required to ensure appropriate recovery of costs.

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RATE SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

MONTHLY RATE FOR EACH
TYPE OF SERVICE:

Rate ($ per Month)

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Type of Light	Watts	Monthly Use (kWh)	Nominal Lumens	Customer-Owned Type I	Customer-Owned Type II	FortisBC-Owned Type III
Fluorescent	*383	140	21,800	27.43		
Mercury Vapour	*125	55	5,000	11.00	11.00	24.30
	*175	78	7,000	15.52	15.52	28.91
	*250	107	10,000	21.31	21.31	34.69
	*400	166	21,000	33.05	33.05	46.43
Sodium Vapour	70	33	6,000	6.67	6.67	19.96
	*100	47	9,000	9.35	9.35	22.72
	*150	70	14,000	13.90	13.90	27.30
	200	91	20,000	18.13	18.13	31.50
	250	111	23,000	22.14	22.14	35.45
	*400	173	45,000	34.46	34.46	47.86

For Type I and Type II, Light Emitting Diode (LED) lighting service will be supplied at a Monthly rate of 0.1989 per kWh as determined according to the General Terms and Conditions.

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* No longer available at new locations or as replacement fixtures where existing fixtures are being replaced except at the sole discretion of FortisBC.

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OVERDUE
ACCOUNTS: A late payment charge of 1 1/2% (compounded monthly 19.56% per annum) will be assessed each month on all outstanding balances not paid by the due date.

PERMANENT RATE
ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 60 - IRRIGATION AND DRAINAGE

AVAILABLE: For an irrigation and drainage season commencing April 1st each year and terminating October 31st each year. Meter readings will be taken within 10 Business Days of the commencement and termination of the irrigation and drainage season. During the non-irrigation season Customers will be automatically transferred to the applicable Commercial rate and billings prorated for a partial first or final service Month when read dates are outside of the 10 Day band.

APPLICABLE: To motors at one point of delivery, which are to be used primarily for irrigation and drainage purposes. This schedule applies to electric service when taken at FortisBC's standard secondary voltage. Incidental lighting essential to the pumping operation will be allowed on this schedule provided that the Customer supplies and installs his own transformers and other necessary equipment as required. Service to motors of 5 HP or less will be single phase, unless FortisBC specifically agrees to supply three phase.

BILLING: Bills will be rendered Monthly or bimonthly but may be estimated in periods of low consumption or when access is restricted.

MONTHLY RATE: All kW.h @ 7.240¢ per kW.h

CUSTOMER CHARGE: $22.09 per Month

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

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RATE SCHEDULE 61 - IRRIGATION AND DRAINAGE - TIME OF USE

APPLICABLE: For Customers normally supplied under Rate Schedule 60. Service to motors of 5 HP or less will be single phase, unless FortisBC specifically agrees to supply three phase. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

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RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	17.869
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	7.303
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	4.714

plus:

CUSTOMER CHARGE: $22.09 per Month

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OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

SCHEDULE 85 - GREEN POWER RIDER

APPLICABLE: To any current rate Schedules and on the same terms applicable to rate Schedule under which Service is taken, for the purchase of Electricity from environmentally desirable technologies.

RATE: OPTION A - In addition to all charges on the applicable rate Schedule, an additional charge, of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

OPTION B - In addition to all charges on applicable rate Schedule, the Customer may select a dollar amount of their choosing to be added to their periodic billing, but in no case will the amount be less than $2.50 per Month.

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SCHEDULE 90 - DEMAND-SIDE MANAGEMENT SERVICES

APPLICABLE: To all Customers in all areas served by FortisBC and its municipal wholesale Customers.

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OBJECTIVE: The purpose of FortisBC's Demand-Side Management (DSM) Services is to promote the efficient use of Electricity, in terms of consumption (Conservation) and/or timing (Demand Response).

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PROGRAMS: DSM programs, compliant with applicable regulations, address electrical end-uses, through approved Measure(s), which may consist of an energy-efficient product, device, piece of equipment, system, building or process design and/or operational practice which exceeds applicable codes and/or current practice.

FortisBC will maintain an updated DSM program listing on its website, available in print format, detailing current program offerings and rules.

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FINANCIAL DETAILS: DSM programs will consist of monetary incentives provided by FortisBC in the form of custom option or product option offerings to promote the purchase and installation of approved Measures. Incentives are targeted to Customers but may also be provided to trade allies who provide or install the Measures.

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Monetary incentives are based on the annual kWh savings, or the on-peak kW reduction, attained through the Measure as determined on a prescriptive or custom calculation basis.

Monetary incentives are capped to the lesser of:

i. FortisBC's long-term avoided power purchase costs,

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ii. 50% of installed Measure cost for existing construction,

iii. 100% of incremental cost for new construction, or

iv. The amount sufficient for the Customer to achieve a two-Year payback.

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Monetary incentives may alternately consist of low-cost financing O.A.C. for residential Customers only.

DSM Services may also consist of non-monetary offerings in the form of: public information, educational programs, or training; audits of Customer Premises or processes or Measures and reports thereof; product samples; pilot projects to test new Measures; and market transformation activities undertaken in conjunction with other utilities and/or governments.

SCHEDULE 90 – DEMAND-SIDE MANAGEMENT SERVICES **(Cont'd)**

TERMS AND CONDITIONS

The following terms and conditions are an integral part of the Demand-Side Management Services listed under Schedule 90:

FINANCIAL INCENTIVES

1. In order to be eligible for financial incentives, a Customer must receive FortisBC's approval prior to initiation of work on the approved Measure.

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2. Only those audit or upgrade costs which are pertinent to DSM considerations will be eligible for financial incentives. An estimate of costs related to such issues as obsolescence, depreciation, maintenance, plant betterment and environmental concerns will be made to isolate that portion of the cost strictly related to energy.
3. Where incentives are in excess of $10,000, payment of one half of the rebate will be deferred for up to one Year. Upon confirmation of project savings, the remaining portion of the rebate will be paid pro rata to the energy savings. No interest will be paid on the withheld portion. Irrespective of actual savings, the final rebate will not exceed the original estimated rebate.

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4. For those Customers in receipt of an incentive in excess of $20,000, the unamortized balance of financial incentives paid to or on behalf of the Customer, under Rate Schedule 90 will be remitted to FortisBC within 30 Days of billing, if:

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   (a) the incented equipment or facilities are disabled or removed;

   (b) the Customer's electrical load is reduced by more than 50% for a continuous period of twelve Months or longer; or

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   (c) over 50% of the Electricity previously provided by FortisBC is replaced by another source including self-generation or another supplier.

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   In regards to (c) above, the repayment will be prorated based on the amount of energy replaced compared to the amount of energy supplied by FortisBC in the Year immediately preceding the Electricity replacement.

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5. Any consulting or study subsidy offered under the Demand-Side Management tariff is contingent upon available budget and resources. When FortisBC pays more than $1,500 for these Services on behalf of a Customer, any incentive amount that is eventually payable to that Customer will be reduced by the amount of the consulting or study contribution.

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SCHEDULE 91 – ON-BILL FINANCING PILOT PROGRAM - CLOSED

APPLICABLE: To all eligible Customers located in the City of Kelowna and the Regional District of Okanagan-Similkameen, excluding the City of Penticton and the District of Summerland for the energy efficiency improvement to an eligible Premises, or a part of an eligible Premises.

ELIGIBLE CUSTOMERS: In order to be eligible for the Loan, the Customer must:

(a) receive or will receive Service from FortisBC;

(b) participate in the Equal Payment Plan as specified in Section 8.6 (Equal Payment Plan);

(c) have paid on or before the due date, all or all but one of FortisBC's bills issued, if any, during the twelve Month period preceding the date of the application for the Loan;

(d) as of the date for applying for the Loan, have a credit rating of at least 650 on the Equifax Beacon rating system (i.e. a credit rating of 650 or higher); and

(e) be the lawful owner of an eligible Premises evidenced by a copy of the Land Title Certificate.

If the copy of the Land Title Certificate is not available, the Customer must consent to FortisBC to conduct a search of the Land Title Office to verify ownership.

ELIGIBLE PREMISES: The Loan is for improving energy efficiency to a Premises, or part of a Premises that is a residential building of three stories or less that occupies no more than 600 square meters of ground service, is habitable all year and is:

(a) a detached home;

(b) a building that is part of a complex of side-by-side attached buildings; or

(c) a mobile home on a permanent foundation.

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SCHEDULE 91 – ON-BILL FINANCING PILOT PROGRAM (cont'd)

ELIGIBLE ENERGY EFFICIENCY IMPROVEMENTS: The energy efficiency improvements to a Premises or a part of a Premises eligible for the Loan must

(a) fall into one of the following categories:

(i) air sealing;

(ii) mechanical ventilation;

(iii) attic insulation;

(iv) exterior wall insulation;

(v) basement, crawlspace and header insulation;

(vi) primary method of heating occupied space;

(vii) domestic hot water heating; or

(viii) window and door replacement; and

(b) be a qualified retrofit measure under the Ministry of Energy, Mines and Natural Gas LiveSmart BC program.

ENERGY REPORT: To be eligible for the Loan, the improvements specified herein must be recommended in an energy report respecting the eligible Premises or the part of the Premises. The energy report must be completed and signed by a qualified energy advisor no more than eighteen calendar months before the date of the Financing Agreement. A qualified energy advisor is certified as such by Natural Resources Canada and employed by or under contract with a service organization licenced by Natural Resources Canada to perform EnerGuide Rating System evaluations.

<u>SCHEDULE 91 – ON-BILL FINANCING PILOT PROGRAM</u> (cont'd)

APPLICATION <u>FOR LOAN:</u>

A Customer may apply for the Loan to FortisBC in the same way as applying for Services with FortisBC under Section 2 (Application for Service) of the General Terms and Conditions. The number of Customers eligible to receive the Loan will be limited and the determination of eligibility will be made by FortisBC in its sole discretion, acting reasonably. FortisBC reserves the right to deny a Loan to a Customer should FortisBC determine that the terms and conditions for the On-Bill Financing Pilot Program and/or the provisions of the *Improvement Financing Regulations* are not met.

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COMPLETION OF <u>IMPROVEMENTS:</u>

The energy efficiency improvements must be completed

(a) by the owner of the Premises or a part of the Premises or by a "qualified person" as defined in the *Improvement Financing Regulation*; and

(b) within six calendar months of the date FortisBC approves the application for the Loan.

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Failure to complete improvements as specified herein may result in withdrawal of the approval for the Loan or termination of the Financing Agreement.

RIGHT TO <u>INSPECT:</u>

FortisBC has the right to inspect the Premises or the part of the Premises subject to the Financing Agreement at a reasonable time up to 36 calendar months after the completion of the improvements.

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SCHEDULE 91 – ON-BILL FINANCING PILOT PROGRAM (cont'd)

TERMINATION
OF PROGRAM: FortisBC may terminate the On-Bill Financing Pilot Program at any time and without notice subject to the provisions of the *Clean Energy Act* [SBC 2010], c. 22 and any regulations promulgated thereunder. Notwithstanding the foregoing, all Financing Agreements and obligations thereunder duly entered into under the On-Bill Financing Pilot Program up to the date of termination will survive such termination.

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BASIC TERMS OF THE FINANCING AGREEMENT

In addition to the terms listed above under Schedule 91 and the charges, if applicable, for Disconnection and Reconnection of Meter, Required Cheque Service, and Collection listed under Schedule 80, the following terms and conditions are an integral part of the On-Bill Financing Pilot Program:

1. The Customer must meet all the eligible requirements contained herein and sign the applicable Financing Agreement provided by FortisBC in order to receive the Loan.

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2. The Financing Agreements under the On-Bill Financing Pilot Program have a term of ten Years.

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3. The Loan will be paid in 120 equal Monthly installments. The equal Monthly installments will form a component of FortisBC's electric utility bill known as the On-Bill Financing Charge and will be subject to normal utility collection procedures, including service disconnect, as outlined in Section 8.2 (Payment of Accounts).

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4. Available Loan amounts under the On-Bill Financing Pilot Program are limited to a minimum principal amount of $1,000 and a maximum principal amount of $10,000 per Premises.

5. The interest charged by FortisBC on the principal amount of the Loan does not exceed 4.5 annual percentages.

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SCHEDULE 91 – ON-BILL FINANCING PILOT PROGRAM (cont'd)

BASIC TERMS OF THE FINANCING AGREEMENT (cont'd)

6. Subject to FortisBC's written consent, the Customer may transfer the Financing Agreement upon the sale of the Premises or the part of the Premises subject to the Financing Agreement to a new owner provided the new owner must:

   (a) meet all eligibility requirements established herein;

   (b) be approved by FortisBC; and

   (c) sign a Notice of Transfer provided in the Improvement Financing Regulation as a schedule.

Should the new owner not meet the eligibility requirements or should the new owner not be approved by FortisBC, the balance of the Loan amount due under the Financing Agreement must be paid in full, including applicable interest amounts.

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7. The Customer's obligations under the Financing Agreement are not discharged until

   (a) the full amount payable under the Financing Agreement is paid; or

   (b) the Financing Agreement is transferred as specified herein.

RATE SCHEDULE 95 - NET METERING

DEFINITION:

Customer-Generator - An electric Service Customer of FortisBC that also utilizes the output of a Net Metered System.

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Net Consumption - Net Consumption occurs at any point in time where the Electricity required to serve the Customer-Generator's load exceeds that being generated by the Customer-Generator's Net Metered System.

Net Generation - Net Generation occurs at any point in time where Electricity supplied by FortisBC to the Customer-Generator is less than that being generated by the Customer-Generator's Net Metering System.

Net Excess Generation - Net Excess Generation results when over a billing period, Net Generation exceeds Net Consumption.

Net Metering - Net Metering is a metering and billing practice that allows for the flow of Electricity both to and from the Customer through a single, bi-directional meter. With Net Metering, consumers with small, privately-owned generators can efficiently offset part or all of their own electrical requirements by utilizing their own generation.

Net Metered System - A facility for the production of electric energy that:

(a) uses as its fuel, a source defined as a clean and renewable resource in the BC Energy Plan;

(b) has a design capacity of not more than 50 kW;

(c) is located on the Customer-Generator's Premises;

(d) operates in parallel with FortisBC's transmission or distribution facilities; and

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(e) is intended to offset part or all of the Customer-Generator's requirements for Electricity.

APPLICABLE: To FortisBC Customers receiving Service under Rate Schedules 1, 2A, 20, 21, 22, 22 A, 23 A, 60, 61.

RATE SCHEDULE 95 - NET METERING (Cont'd)

ELIGIBILITY: To be eligible to participate in the Net Metering Program, Customers must generate a portion or all of their own retail Electricity requirements using a renewable energy source. The generation equipment must be located on the Customer's Premises, Service only the Customer's Premises and must be intended to offset a portion or all of the Customer's requirements for Electricity.

Clean or renewable resources include sources of energy that are constantly renewed by natural processes, such as water power, solar energy, wind energy, geothermal energy, wood residue energy, and energy from organic municipal waste, and will have a maximum installed generating capacity of no greater than 50 kW.

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RATE: A Customer enrolled in the Net Metering Program will be billed as set forth in the Rate Schedule under which the Customer receives electric Service from FortisBC and as specified in the Net Metering Billing Calculation section in this schedule.

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BILLING CALCULATION:

1. Net metering will be, for billing purposes, the net consumption at FortisBC's Service meter(s).
2. If the eligible Customer-Generator is a net consumer of energy in any billing period, the eligible Customer generator will be billed in accordance with the Customer-Generator's applicable Rate Schedule.
3. If in any billing period, the eligible Customer-Generator is a net generator of energy, the Net Excess Generation will be valued at the rates specified in the applicable Rate Schedule and credited to the Customers account.
4. For eligible Customers receiving Service under a Time-of-Use (TOU) Rate Schedule, consumption and generation during On-Peak Hours will be recorded and netted separately from consumption and generation during Off-Peak Hours such that any charges or credits applied to the account reflect the appropriate time-dependent value for the energy.
5. In the event that the operation of a renewable energy generating system results in a credit balance on the Customer-Generator's account at the end of a calendar Year, the credit will be purchased by FortisBC. If such amounts are not large, they will be carried forward and included in the billing calculation for the next period at the discretion of FortisBC.

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RATE SCHEDULE 95 - NET METERING (Cont'd)

SPECIAL CONDITIONS:

1. Prior to the interconnection of a Net Metering System the Customer-Generator must submit a Net Metering Application for review and execute a written Net Metering Interconnection Agreement with FortisBC.

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2. The Net Metered System and all wiring, equipment and devices forming part of it, will conform to FortisBC's, "GUIDELINES FOR OPERATING, METERING And PROTECTIVE RELAYING FOR NET METERING SYSTEMS UP TO 50 kW And VOLTAGE BELOW 750 VOLTS" and will be installed, maintained and operated in accordance with those Requirements.

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3. Unless otherwise approved by FortisBC, the Customer-generator's Service will be metered with a single, bi-directional meter.

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4. The Contract Period for Service under this schedule will be one (1) Year and thereafter will be renewed for successive one-Year periods. After the initial period, the Customer may terminate Service under this Rider by giving at least sixty (60) Days previous notice of such Termination in writing to FortisBC.

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5. If the Customer-Generator voluntarily terminates the net-metering Service, the Service may not be renewed for a period of 12 Months from the date of Termination.

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6. FortisBC maintains the right to inspect the facilities with reasonable prior notice and at a reasonable time of Day.

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7. FortisBC maintains the right to disconnect, without liability, the Customer-Generator for issues relating to safety and reliability.

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8. Inflows of Electricity from the FortisBC System to the Customer-Generator, and outflows of Electricity from the Customer-Generators Net Metering System to the FortisBC System, will normally be determined by means of a single meter capable of measuring flows of Electricity in both directions.

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9. Alternatively, if FortisBC determines that flows of Electricity in both directions cannot be reliably determined by a single meter, or that dual metering will be more cost-effective, FortisBC may require that, at the Customers cost, separate meter bases be installed to measure inflows and outflows of Electricity.

10. Except as specifically set forth herein, Service supplied under this schedule is subject to the General Terms and Conditions set forth in FortisBC's Electric Tariff on file with the British Columbia Utilities Commission.

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RATE SCHEDULE 95 - NET METERING (Cont'd)

SPECIAL CONDITIONS: (Cont'd)

1. A Net Metered System used by a Customer-Generator will meet all applicable safety and performance standards established as set forth in FortisBC's Rules and Regulations.
2. A Customer-Generator will, at its expense, provide lockable switching equipment capable of isolating the Net Metered System from FortisBC's system. Such equipment will be approved by FortisBC and will be accessible by FortisBC at all times.
3. The Customer-Generator is responsible for all costs associated with the Net Metered System and is also responsible for all costs related to any modifications to the Net Metered System that may be required by FortisBC including but not limited to safety and reliability.
4. The Customer will indemnify and hold FortisBC or its agents harmless for any damages resulting to FortisBC or its agents as a result of the Customer's use, ownership, or operation of the Customer's facilities other than damages resulting to FortisBC or its agents directly as a result of FortisBC or its agents own negligence or willful misconduct, including, but not limited to, any consequential damages suffered by FortisBC or its agents. The Customer is solely responsible for ensuring that the Customer's facilities operate and function properly in parallel with FortisBC's system and will release FortisBC or its agents from any liability resulting to the Customer from the parallel operation of the Customer's facilities with FortisBC's system other than damages resulting to the Customer from the parallel operation of the Customer's facilities with FortisBC's system directly as a result of FortisBC or its agents own negligence or willful misconduct.

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RATE SCHEDULE 100 - NETWORK INTEGRATION TRANSMISSION SERVICE

AVAILABILITY: For Network Integration Transmission Service.

RATE: Monthly Network Transmission Revenue Requirement:

Customers will be charged the applicable Load Ratio Share of one twelfth (1/12th) of the Network Transmission Revenue Requirement per Month. The Network Transmission Revenue Requirement is as set forth in Attachment H to Electric Tariff Supplement No. 7.

NOTE: The terms and conditions under which Network Integration Transmission Service is supplied are contained in Electric Tariff Supplement No. 7 and capitalized terms appearing in this Rate Schedule, unless otherwise noted, will have the meaning ascribed to them therein.

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RATE SCHEDULE 101 - LONG-TERM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

AVAILABILITY: For transmission of Electricity on a firm basis from one or more Point(s) of Receipt (POR) to one or more Point(s) of Delivery (POD).

ANNUAL RATE FOR LONG-TERM FIRM SERVICE:

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 (BC Hydro) and the power is being delivered to a load with or beyond the BC 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.

RATES FOR SHORT-TERM FIRM SERVICE

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 the POD is a point of interconnection between the Transmission System and the transmission system of BC Hydro and the power is being delivered to a load within or beyond the BC 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.

MINIMUM PRICE: $0.002 per kW per Hour

MAXIMUM PRICE: The Transmission Customer will pay each Month for Reserved Capacity designated at the POD at rates not to exceed the applicable charges set forth below.

Delivery	Transmission	Distribution
	per kW of Reserved Capacity Demand	
Monthly	$4.20	$8.07
Weekly	$0.9692	$1.8623
Daily	$0.1381	$0.2653
Hourly	$0.0058	$0.0111

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Wholesale Service-Transmission¶
A Basic Charge of $467 per POD to a maximum of $467 in any calendar month,¶
plus:¶
$5.10 per kVA of Reserved Capacity Billing Demand.¶
Wholesale Service-Primary¶
A Basic Charge of $2,537 per POD to a maximum of $2,537 in any calendar month, ¶
plus:¶
$9.89 per kVA of Reserved Capacity Billing Demand.¶
Large Commercial Service-Transmission¶
A Basic Charge of $3,185 per POD to a maximum of $3,185 in any calendar month, ¶
plus:¶
$5.41 per kVA of Reserved Capacity Billing Demand.¶
RATES FOR SHORT-TERM FIRM SERVICE¶
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 the POD is a point of interconnection between the Transmission System and the transmission system of the B.C. Hydro and Power Authority.¶
RATE SCHEDULE 101 - LONG-TERM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE (Cont'd)¶

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RATE SCHEDULE 101 - LONG-TERM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE (Cont'd)

SPECIAL CONDITION:

Discounts: Three principal requirements apply to discounts for Transmission Service as follows:

1. any offer of a discount made must be announced to all Transmission Customers on the FBC website in a timely manner;

2. any Customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must be provided to other Transmission Customers on the FBC website; and

3. once a discount is negotiated, details must be immediately posted on the FBC website. For any discount agreed upon for Service on a path, from POR to POD, an offer of the same discounted transmission Service rate for the same time period must be made for all unconstrained transmission paths that go to the same POD on the Transmission System.

NOTE: The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement 7. Capitalized terms appearing in this Rate Schedule, unless otherwise noted, will have the meaning ascribed to them therein.

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PENALTY CHARGE:

A penalty charge will be applied at the rate of 125 per cent of the applicable rate for all usage in excess of the Reserved Capacity.

RESERVED CAPACITY BILLING DEMAND:

The sum of the Reserved Capacity designated at each POD for the applicable period.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 103 - SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

PREAMBLE: This Service is required to schedule the movement of power through, out of, or within the Service territory.

The Transmission Customer must purchase this Service if taking supply under Rate Schedules 100, 101 and 102.

MAXIMUM MONTHLY RATE: $0.16690 per kW.h of Reserved Capacity per Month

MAXIMUM WEEKLY RATE: $0.03850 per kW.h of Reserved Capacity per week

MAXIMUM DAILY RATE: $0.00550 per kW.h of Reserved Capacity per day

MAXIMUM HOURLY RATE: $0.00023 per kW.h of Reserved Capacity per Hour

NOTE: A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

Deleted: RATE SCHEDULE 102 - NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE¶
AVAILABILITY: For transmission of Electricity on a Non-firm basis from one or more Point(s) of Receipt (POR) to one or more Point(s) of Delivery (POD).¶
RATES FOR SHORT-TERM NON-FIRM SERVICE¶
The Transmission Customer shallwill pay each month for Reserved Capacity designated at the POR at the posted prices which will be above a minimum price and below a maximum price as set out below.¶
MINIMUM PRICE: $0.001 per kW per hHour¶
MAXIMUM PRICE:¶
The Transmission Customer shallwill 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.¶
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Wholesale Service-Primary:

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Large Commercial Service-Transmission:

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RATE SCHEDULE 104 - REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICES

PREAMBLE: In order to maintain Transmission Voltages on transmission facilities within acceptable limits, generation facilities under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain Transmission Voltages within limits that are generally accepted in the region.

The Transmission Customer must purchase this Service if taking supply under Rate Schedules 100, 101, and 102.

RATE: $0.82500 per kW.h of Reserved Capacity per Hour

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Deleted: Wholesale Service-Primary: $0.00132 per kW.h
Large Commercial Service-Transmission: $0.00132 per kW.h

NOTE: A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 105 - REGULATION AND FREQUENCY RESPONSE SERVICE

PREAMBLE: Regulation and Frequency Response (RFR) Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The Transmission Customer must either purchase this Service from FortisBC or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below.

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AVAILABILITY: In support of the transmission of Electricity under Rate Schedules 100 and 101.

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RATE: $9.31 per mega-watt per Hour of generating capacity requested for RFR.

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The required amount of RFR Service is a minimum of 2% of the Customer's load located in FortisBC's Service territory.

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NOTE: A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 106 - ENERGY IMBALANCE SERVICE

PREAMBLE: Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a FortisBC's Service territory over a single Hour. FortisBC must offer this Service when the transmission Service is used to serve load within its Service area. The Transmission Customer must either purchase this Service from FortisBC or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. FortisBC will establish a deviation band of +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied Hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Parties should attempt to eliminate energy imbalances within the limits of the deviation band within thirty (30) Days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by FortisBC. If an energy imbalance is not corrected within thirty (30) Days or a reasonable period of time that is generally accepted in the region and consistently adhered to by FortisBC, the Transmission Customer will compensate FortisBC for such Service. Energy imbalances outside the deviation band will be subject to charges to be specified by FortisBC. The charges for Energy Imbalance Service are set forth below.

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AVAILABILITY: In support of the transmission of Electricity under Rate Schedules 100 and 101.

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ENERGY IMBALANCE: Energy imbalances are calculated Hourly based on deviations from scheduled generation and load. Positive imbalances occur when actual generation is greater than scheduled or when actual load is less than scheduled load and results in a delivery of Energy from the Customer to FortisBC. Negative imbalances occur when actual generation is less than schedule generation or when actual load is greater than scheduled load and results in a delivery of Energy from FortisBC to the Customer.

RATE SCHEDULE 106 - ENERGY IMBALANCE SERVICE (Cont'd)

A positive imbalance will be credited as the lower of:

(i) The Tranche 1 Energy Price set out in BC Hydro Rate Schedule 3808 as of January 1 in the calendar Year in which the available surplus power is delivered; and

(ii) The Hourly Powerdex Mid-Columbia index price for the Hour in which the positive Energy Imbalance Service is taken by the Customer. In Hours in which the Mid-Columbia index price is negative, the negative value will be used result in a charge to the Customer for those Hours;

plus:

(iii) An administrative premium of 10 percent will be subtracted from the credited amount or added to the charged amount if the Mid-Columbia index price was negative.

A negative imbalance will be charged as follows:

1. For Hourly negative Energy Imbalance Service less than or equal to 4 MW, the charge will be:

(i) The amount of negative Energy Imbalance Service x (1 x loss compensation percentage under Rate Schedule 109);

multiplied by:

(ii) The Hourly Powerdex Mid-Columbia per kW.h price for the Hour in which the negative Energy Imbalance Service is taken by the Customer. In Hours in which the Mid-Columbia per kW.h price is negative a zero value will be used;

plus:

(iii) The Bonneville Power Authority's (BPA) wheeling rate from B.C.-U.S. Border to Mid-Columbia. per kW.h;

plus:

(iv) An administrative premium of 10 percent.

RATE SCHEDULE 106 - ENERGY IMBALANCE SERVICE (Cont'd)

2. For hourly negative Energy Imbalance Service greater than 4 MW, the charge will be:

(i) The amount of negative Energy Imbalance Service x (1 x loss compensation percentage under Rate Schedule 109);

multiplied by the greater of:

(ii) $50/MWh, or

(iii) 150 percent of the Hourly Powerdex Mid-Columbia per kWh price for the Hour in which the negative Energy Imbalance Service is taken by the Customer. In hours in which the Mid-Columbia price is negative, a zero value will be used;

plus:

(iv) The BPA wheeling rate from B.C.-U.S. Border to Mid-C per kW.h;

plus:

(iv) An administrative premium of 10 percent.

NOTE: BPA's wheeling rate is available on the BPA website.

A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017

Deleted: Customers are allowed to maintain a ±1.5% balance between generation (minus losses) and load within the hHour. The ±1.5% hHourly balance limit is based on the capacity reserved. Positive hHourly imbalances within the ±1.5% band not eliminated within 30 dDays, will attract a credit that is equal to the CompanyFortisBC's minimum monthly cost of purchasing energy. If the CompanyFortisBC does not purchase energy during the month, the previous minimum price will be used. Positive hHourly imbalances outside the ±1.5% band will be forfeit.¶
For negative energy imbalances (when generation minus losses is less than load) that fall within the ±1.5% band and are not eliminated within 30 dDays, the energy imbalance charge will be:¶
RATE SCHEDULE 106 - ENERGY IMBALANCE SERVICE (Cont'd)¶
RATE Wholesale Service-Transmission: $0.05043 per kW.h¶
Wholesale Service-Primary: $0.04800 per kW.h¶
Large Commercial Service-Transmission: $0.04798 per kW.h¶
For any negative energy imbalances (when generation minus losses is less than load) that fall outside the ±1.5% band the energy imbalance charge will be the actual cost the CompanyFortisBC incurs in supplying that imbalance, plus 10%.¶
NOTE: A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.¶

RATE SCHEDULE 107 - OPERATING RESERVE (OR) - SPINNING RESERVE SERVICE

PREAMBLE: Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. FortisBC must offer this Service when the transmission Service is used to serve load within its Service area. The Transmission Customer must either purchase this Service from FortisBC or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below.

AVAILABILITY: In support of the transmission of Electricity under Rate Schedules 100 and 101.

RATE: $9.31 per mega-watt per Hour of generating Capacity requested for OR - Spinning.

The required amount of Spinning Reserve Service, for a Customer's load located in FortisBC's Service area, depends upon the type of generation serving the load. When the load is served by hydro generation, the required amount of Spinning Reserve Service is a minimum of 2.5% of the Customer's load. When the load is served by thermal generation, the required amount of Spinning Reserve Service is a minimum of 3.5% of the Customer's load.

NOTE: A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

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RATE SCHEDULE 108 – OPERATING RESERVE (OR) – SUPPLEMENTAL RESERVE SERVICE

PREAMBLE: Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. FortisBC must offer this Service when the transmission Service is used to serve load within its Service Area. The Transmission Customer must either purchase this Service from FortisBC or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below.

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AVAILABILITY: In support of the transmission of Electricity under Rate Schedule 100 and 101.

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RATE: $9.31 per mega-watt per Hour of generating Capacity requested for OR-Supplemental.

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The required amount of Supplemental Reserve Service, for a Customer's load located in FortisBC Service area, depends upon the type of generation serving the load. When the load is served by hydro generation, the required amount of Supplemental Reserve Service is a minimum of 2.5% of the Customer's load. When the load is served by thermal generation, the required amount of Supplemental Reserve Service is a minimum of 3.5% of the Customer's load.

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NOTE: A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017

RATE SCHEDULE 109 - TRANSMISSION LOSSES

APPLICABLE: All transactions under rate Schedules 100 and 101 will incur real power losses as follows:

Wholesale Service - Transmission	6.08%
Wholesale Service - Primary	11.53%
Large Commercial Service - Transmission	6.08%

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RATE SCHEDULE 110 – GENERAL WHEELING SERVICE – BC HYDRO

AVAILABILITY: Available to BC Hydro for the Wheeling of electricity over FortisBC's transmission facilities in accordance with the terms and conditions as set forth in Electric Tariff Supplement No. 9.

APPLICABLE: Applicable to the Point of Supply and the Point of Delivery as specified in Electric Tariff Supplement No. 9.

ANNUAL RATE: The annual rate for Wheeling from the Point of Supply to the Point of Delivery, pursuant to Tariff Supplement No. 9, will be adjusted by the annual rate of inflation published by Statistics Canada using the British Columbia Consumer Price Index (all items) for the Month of January in the calendar Year in which the adjustment is made. The base rate is as follows:

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Point of Supply to Point of Delivery

On 1 January 2017, $26,118.89 per MVA of Nominated Wheeling Demand

MONTH CHARGE: The Monthly charge will be one twelfth of the above annual rate per MVA of Nominated Wheeling Demand for the Point of Supply.

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NOMINATED WHEELING DEMAND: The maximum amount, as determined in Section 4 of Electric Tariff Supplement No. 9, at which FortisBC will Wheel electricity for BC Hydro during a stated year.

EMERGENCY WHEELING: The rate for electricity deliveries that exceed the Nominated Wheeling Demand will be as set forth in Section 6 of Electric Tariff Supplement No. 9.

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DEFINITIONS: All terms capitalized above are defined in Electric Tariff Supplement No. 9.

RATE SCHEDULE 111 – WANETA EXPANSION RESIDUAL CAPACITY – BC HYDRO

AVAILABILITY: Available to BC Hydro for the purchase of WAX Capacity in accordance with the terms and conditions as set forth in Electric Tariff Supplement No. 10 until September 30, 2025.

APPLICABLE: Purchased Capacity is deemed to be available to BC Hydro at the Kootenay Interconnection, as specified in Electric Tariff Supplement No. 10.

HOURLY CAPACITY RATE: The Monthly Demand Charge, in $ per kW/Month, will be as determined pursuant to the Power Purchase Agreement (including all rate riders and excluding any taxes) and set out from time to time in BC Hydro's Rate Schedule 3808 or its successor Rate Schedule.

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The Hourly capacity rate ($ per MW/Hour) for the Purchased Capacity made available to BC Hydro is the Monthly Demand Charge multiplied by 1000 and divided by 730.

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PURCHASED CAPACITY: The amount of WAX Capacity that will be made available to BC Hydro during each Hour of the Term will be the lesser of:

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(i) 50 MW; and

(ii) the amount of Residual Capacity (in MW) for that Hour, rounded to one decimal place.

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The amounts payable by BC Hydro for each Hour of a Billing Month will be summed, and the sum for all Hours of the Billing Month will be invoiced by FortisBC.

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DEFINITIONS: All terms capitalized above are defined in Electric Tariff Supplement No. 10.

Note: The terms and conditions under which service is provided to BC Hydro are contained in the Residual Capacity Agreement, Electric Tariff Supplement No. 10.

Appendix H

CLEAN FBC ELECTRIC TARIFF

FORTISBC INC.

ELECTRIC TARIFF

FOR SERVICE IN THE WEST KOOTENAY AND OKANAGAN AREAS

GENERAL TERMS AND CONDITIONS

AND

RATE SCHEDULES

EXPLANATION OF SYMBOLS APPEARING ON TARIFF PAGES
A – signifies Increase
C – signifies Change
D – signifies Decrease
N – signifies New
O – signifies Omission
R – signifies Reduction

INDEX **Page**

GENERAL TERMS AND CONDITIONS

FortisBC will furnish electric Service in accordance with the Rate Schedules and these General Terms and Conditions filed with and approved by the British Columbia Utilities Commission. Copies are available on FortisBC's web site or upon request.

The Customer, by taking Service, agrees to abide by the provisions of these General Terms and Conditions.

Unless the context indicates otherwise, in the General Terms and Conditions and Rate Schedules of FortisBC the following words have the following meanings:

1. DEFINITIONS

Advanced (or AMI) Meter	An Electricity meter with integrated wireless transmit functions and those functions are activated.
Billing Demand	The Demand used in establishing the Demand portion of billing for Service during a specific billing period.
British Columbia Utilities Commission	Means the British Columbia Utilities Commission constituted under the Utilities Commission Act of British Columbia and includes and is also a reference to (a) any commission that is a successor to such commission, and (b) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the Utilities Commission Act of British Columbia.
Business Day	Means a Day that commences on other than a Saturday, a Sunday, or a statutory holiday in the Province of British Columbia.
Commercial Service	Service for business, commercial, institutional, or industrial use. Commercial Service is available as an alternative to Residential Service only in the circumstances described in Section 6.3.1 (Partial Commercial Use). FortisBC may require documentation to support Commercial use of a Premises for the purpose of being billed at Commercial Service rates.
Company Contribution	Means FortisBC's financial contribution towards the Extension Cost as specified in Section 16 (Extensions).

Contract Demand	The Demand reserved for the Customer by FortisBC and contracted for by the Customer.
Customer	Means a Person who is being provided Service or who has filed an application for Service with FortisBC that has been approved by FortisBC.
Customer Charge	Means a fixed charge required to be paid by a Customer for Service as specified in the applicable Rate Schedule.
Customer Portion of Costs (CPC)	Means the Extension Cost less the Company Contribution towards the Extension.
Day	Means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the applicable Service Agreement.
Demand	The rate of delivery of Electricity measured in kilowatts (kW), kilovolt-amperes (kVA), or horsepower (hp) over a given period of time.
Drop Service	The portion of an overhead Service connection extending not more than 30 metres onto the Customer's property and not requiring any intermediate support on the Customer's property.
Electricity	Means both electric Demand and electric Energy or either, as the context requires.
Energy	Electric consumption measured in kilowatt hours (kWh).
Extension	Means an addition to, or extension of, FortisBC’s distribution system including an addition or extension on public or private property.
Extension Cost	Means FortisBC’s estimated cost of constructing an Extension including the cost of labour, material and construction equipment. Extensions Cost includes the cost of connecting the Extension to FortisBC’s distribution system, inspection costs, survey costs, and permit costs. If, in FortisBC’s opinion, upgrades to FortisBC’s distribution system would be beneficial for Service to other Customers, the extra cost of this reinforcement is excluded from the Extension Cost.
Financing Agreement	An agreement under which FortisBC provides financing to a Customer for improving the energy efficiency of a Premises, or a part of a Premises.

FortisBC	Means FortisBC Inc., a body corporate incorporated pursuant to the laws of the Province of British Columbia under number 0778288.
FortisBC System	Means the Electricity transmission and distribution system owned and operated by FortisBC, as such system is expanded, reduced or modified from time to time.
Hour	Means any consecutive 60 minute period.
Landlord	Means a Person who, being the owner of real property, or the agent of that owner, who has leased or rented the property to a Tenant.
Load Factor	The percentage determined by dividing the Customer's average Demand over a specific time period by the Customer's maximum Demand during that period.
Loan	The principal amount of financing provided by FortisBC to a Customer, plus interest charged by FortisBC on the amount of financing and any applicable fees and late payment charges.
Meter Set	Means an assembly of FortisBC owned metering, including any ancillary equipment.
Month or Monthly	Means a period of time, for billing purposes, of 27 to 34 consecutive Days. For greater clarity, the term "one month" (unless a calendar month is specified) as used herein and in the Rate Schedules, normally means the time elapsed between the meter reading date of one calendar month and that of the next. The term "two-month period" or bimonthly as used herein and in the Rate Schedules, normally means the time elapsed between the meter reading date of one calendar month and the second following calendar month.
Person	Means a natural person, partnership, corporation, society, unincorporated entity or body politic.
Power Factor	The percentage determined by dividing the Customer's Demand measured in kilowatts by the same Demand measured in kilovolt-amperes.

Point of Delivery	The first point of connection of FortisBC's facilities to the Customer's conductors or equipment at a location designated by or satisfactory to FortisBC, without regard to the location of FortisBC's metering equipment.
Premises	A dwelling, a building, or machinery together with the surrounding land.
Radio-off AMI Meter	An Advanced (or AMI) Meter with integrated wireless transmit functions disabled.
Radio-off Customer	Customers that have a Radio-off AMI Meter installed at their Customer Premises.
Rate Schedule	Means a schedule attached to and forming part of these General Terms and Conditions, which sets out the charges for Service and certain other related terms and conditions for a class of Service.
Residential Premises	Means a Premises used for residential and housekeeping requirements, including: (a) single family dwelling, including any outbuildings supplied through the same meter; (b) single or individually metered single-family townhouse, rowhouse, condominium, duplex or apartment, carriage house, farm building, or manufactured home; (c) at FortisBC's discretion, any other types of living quarters.
Residential Service	Except as provided for in Section 6.3.1 (Partial Commercial Use) and Section 6.3.2 (Other Use), means Service for use at a Residential Premises, including a Residential Premises where a portion is used to carry on a business.
Rider	Means an additional charge or credit attached to a rate.
Service	Means the provision of Electricity or other service by FortisBC.
Service Agreement	Means an agreement between FortisBC and a Customer for the provision of Service.
Suspension	The physical interruption of the supply of Electricity to the Premises independent of whether or not the Service is terminated.

Temporary Service	Means the provision of Service for what FortisBC determines will be a limited period of time.
Tenant	Means a Person who has the temporary use and occupation of real property owned by another Person.
Transformer	Includes transformers, cutouts, lightning arrestors and associated equipment, and the labour to install.
Transmission Voltage	A nominal potential greater than 35,000 volts measured phase to phase.
Termination	The cessation of FortisBC's ongoing responsibility with respect to the supply of Service to the Premises independent of whether or not the Service is suspended.
Primary Voltage	A nominal potential of 750 to 35,000 volts measured phase to phase.
Secondary Voltage	A nominal potential of 750 volts or less measured phase to phase.
Year	Means a period of 12 consecutive Months totalling at least 365 Days.

2. APPLICATION FOR SERVICE

2.1 Application Requirements

Applications for Service will be made via FortisBC's contact center, online at www.fortisbc.com, or by other means acceptable to FortisBC. Applicants for Service will pay the connection or other charges required pursuant to these General Terms and Conditions and Rate Schedules, and will supply all information relating to load, supply requirements and such other matters relating to the Service as FortisBC may require.

Applicants will be required to provide information and identification acceptable to FortisBC.

Applicants may be required to sign an application form for Service. A contractual relationship will be established by the taking of Service in the absence of an application for Service or a signed application, except where a theft of Service has occurred.

A Customer will not transfer or assign a Service application or contract or a Financing Agreement without the written consent of FortisBC.

Applications for Residential Service involving a standard connection of Service should be made via telephone or internet at least ten working Days before Service is required for Contact Centre account set-up. Applications involving the installation of facilities should be discussed with the local FortisBC representative well in advance of the date that Service is required.

2.2 Rate Classification

FortisBC will assist in selecting the Rate Schedule applicable to the Customer's requirements, but will not be responsible if the most favourable rate is not selected. Changing of Rate Schedules will be allowed only if a change is deemed to be more appropriate to the Customer's circumstances. One request to change Rate Schedules will be permitted in any 1 Month period.

At FortisBC's option, where the Customer's load characteristics warrant, Customers served under Rate Schedule 20 may be transferred to Rate Schedule 21 or vice versa.

2.3 Refusal of Application

FortisBC may refuse to accept an application for Service for any of the reasons listed in Section 10.2 (Refusal of Service and Suspension of Service).

2.4 Rental Premises

In the case of rental Premises FortisBC may:

(a) require a Landlord who wishes FortisBC to contract directly with a Tenant to enter into an agreement with FortisBC whereby the Landlord assumes responsibility for that Tenant's non-payment for Service to the Premises;

(b) contract directly with the Landlord as a Customer of FortisBC with respect to any or all Services to the Premises; or

(c) contract directly with each Tenant as a Customer of FortisBC.

2.5 Security Deposit for Payment of Bills

If a Customer or applicant cannot establish or maintain credit to the satisfaction of FortisBC, the Customer or applicant may be required to make a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC. As security for payment of bills, all Customers who have not established or maintained credit to the satisfaction of FortisBC, may be required to provide a security deposit or equivalent form of security, the amount of which may not:

(a) be less than $50; and

(b) exceed an amount equal to the estimate of the total bill for the two highest consecutive Months consumption of Electricity by the applicable Premises.

2.5.1 Interest

FortisBC will pay interest to a Customer on a security deposit at the rate and at the times specified in Section 8.8 (Payment of Interest). Subject to Section 2.5.4 (Application of Deposit), if a security deposit in whole or in part is returned to the Customer for any reason, FortisBC will credit any accrued interest to the Customer's account at that time.

No interest is payable:

(a) on any unclaimed deposit left with FortisBC after the account for which it is security is closed; and

(b) on a deposit held by FortisBC in a form other than cash.

2. APPLICATION FOR SERVICE (Cont'd)

2.5.2 Refund of Deposit

A security deposit may be returned to the Customer at any time if, according to the records of FortisBC, the Customer has at all times during the immediately preceding one Year period maintained an account with FortisBC and paid in full all amounts when due in accordance with the Service Agreement. When the Customer pays the final bill, FortisBC will refund any remaining security deposit plus any accrued interest or cancel the equivalent form of security.

2.5.3 Unclaimed Refund

If FortisBC is unable to locate the Customer to whom a security deposit is payable, FortisBC will take reasonable steps to locate the Customer; but if the security deposit remains unclaimed 10 Years after the date on which it first became refundable, the deposit, together with any interest accrued thereon, will become the absolute property of FortisBC.

2.5.4 Application of Deposit

If a Customer's bill, including the Loan amount, is not paid when due, FortisBC may apply all or any part of the Customer's security deposit or equivalent form of security and any accrued interest toward payment of the bill. Even if FortisBC applies the security deposit or calls on the equivalent form of security, FortisBC may, under Section 10.2 (Refusal of Service and Suspension of Service), discontinue Service to the Customer for failure to pay for Service on time.

2.5.5 Replenish Security Deposit

If a Customer's security deposit or equivalent form of security is called upon by FortisBC towards paying an unpaid bill, the Customer may be required to re-establish the security deposit or equivalent form of security before FortisBC will reconnect or continue Service to the Customer.

2.5.6 Failure to Pay

Failure to pay a security deposit or to provide an equivalent form of security acceptable to FortisBC may, in FortisBC's discretion, result in discontinuance or refusal of Service as set out in Section 10.2 (Refusal of Service and Suspension of Service).

3. TERM OF SERVICE AGREEMENT

3.1 Term of Service

Unless otherwise specifically provided in these General Terms and Conditions, the Rate Schedules, or in any contract between the Customer and FortisBC, the term of Service and obligation to pay the charges under the applicable Rate Schedule for the minimum required term of Service will commence on the Day when FortisBC's Service is connected to the Customer's installation for the purpose of supplying Electricity, and

(a) will be for one Year where the connection does not require more than a Drop Service, unless a shorter period is agreed to by FortisBC; or

(b) will be for five Years where additional facilities other than those for a Drop Service are required; and

(c) will continue thereafter until canceled by written notice of Termination by either party, except that in the case of Customers whose Contract Demand exceeds 200 kVA, 12 Months' prior written notice of Termination will be required and will be given in such manner that the contact terminates with the last Day of a billing period.

3.2 Delay in Taking Service

If, with respect to an application to extend its facilities to any Point of Delivery, FortisBC has reason to believe that Service through that Point of Delivery will not be taken within 30 Days after such Service is available, then FortisBC, in addition to any other payment required, may require payment equivalent to FortisBC's investment, subject to prior written notification to the affected Customer by FortisBC. The payment will be comprised of a monthly charge based on FortisBC's investment multiplied by 2% to provide for a return on investment, depreciation, taxes and other fixed costs.

3.3 Termination of Service Agreement

3.3.1 Termination by Customer

Unless the Service Agreement or applicable Rate Schedule specifies otherwise, the Customer may terminate the Service Agreement after the end of the initial term by giving FortisBC timely notice, and no less than 48 Hours, so that arrangements can be made for final meter reading and billing. Until notice of Termination is given, the Customer will continue to be responsible for all Service supplied unless FortisBC receives an application for Service from a new Customer for the Premises concerned.

3.3.2 Contract Termination by Customer

Notice of Termination requirements for contract Customers will be in accordance with the terms of the contract. If a contract Customer terminates the contract but fails to give the required notice of Termination, the minimum charges for the notice period, as well as any amounts due for Service supplied, will immediately become due and payable.

3.3.3 Effect of Termination

The Customer is not released from any previously existing obligations to FortisBC under a Financing Agreement by terminating the Service Agreement with FortisBC.

3.3.4 Termination by FortisBC

Unless the Service Agreement or applicable Rate Schedule specifies otherwise, FortisBC may terminate the Service Agreement for any reasons by giving the Customer at least 48 Hours written notice.

3.4 Reconnection of Service

If:

(a) Service is terminated:

- (i) at the request of a Customer; or
- (ii) for any of the reasons described in Section 10.2 (Refusal of Service and Suspension of Service); or
- (iii) to permit Customers to make alterations to their Premises; and
- (i) the same Customer or the spouse, employee, contractor, agent or partner of the same Customer requests reconnection of Service to the Premises within one Year, the applicant for reconnection must pay the reconnection charge plus the total of the minimum charges set out in the applicable Rate Schedule which would have been paid by the Customer between the time of termination and the time of reconnection of Service.

If a Service has been disconnected for over 90 Days, or the electrical use within the building has changed substantially, an Electrical Inspection Department permit may be required before reconnection.

4. CONDITIONS OF SERVICE

4.1 Connection of Drop Service

FortisBC will connect a Drop Service to the Customer's Premises after:

(a) receipt of an application for Service;
(b) payment of any applicable charges and deposits;
(c) an Electrical Inspection Department permit to connect Service; and
(d) other permits as may be required by others or by FortisBC.

If space for a Drop Service to the Customer's Premises most convenient to FortisBC is obstructed, FortisBC will charge the Customer for the additional cost of providing Service.

4.2 Connection Requiring Extension

For Service connections requiring more than a Drop Service, the provisions of Section 16 (Extensions) will apply.

4.3 Point of Delivery

Unless otherwise specifically agreed to, the Point of Delivery is the first point of connection of FortisBC's facilities to the Customer's conductors or equipment at a location designated by or satisfactory to FortisBC, without regard to the location of FortisBC's metering equipment.

FortisBC, at its option, may supply Commercial Service through one Point of Delivery to two or more adjacent buildings owned and used as a single business function.

The Rate Schedule for each class of Service named in this tariff is based upon the supply of Service for each Customer through a single Point of Delivery. Additional Service supplied to the same Customer at more than one Point of Delivery will be permitted only at the discretion of and under terms acceptable to FortisBC.

4.4 Ownership of Facilities

Subject to any contractual arrangement and, notwithstanding the payment of any Customer contribution toward the cost of facilities, FortisBC will retain full title to all equipment and facilities installed and maintained by FortisBC.

4.5 Customer Contributions

The Customer may be required to make a contribution as determined under Section 16 (Extensions) toward the cost of facilities in excess of the minimum charges for installation of new/upgraded Services provided for under Section 17 (Standard Charges Schedule) under any of the following conditions:

(a) Extension of Service is in excess of a Drop Service as provided in Section 16 (Extensions);

(b) Service is underground as specified under Section 6.2 (Underground Service);

(c) The nature of the Service is such that the revenue derived from the minimum billing would be insufficient to cover the cost of Service. A contribution would be required for such Services as fire pumps, sirens or emergency supply where the level of consumption is below that necessary to cover the annual costs;

(d) Space for a Drop Service to the Customer's Premise most convenient to FortisBC is obstructed by the Customer's property; or

(e) Facilities must be upgraded significantly to meet an increase in the Customer's load.

If a Customer contribution is required and if the Customer does not receive Service within three Months of the contribution being received by FortisBC, and where the delay in taking Service is not attributable to the Customer, the Customer will receive interest as calculated in Section 8.8 (Payment of Interest) on such payment.

4.6 Revenue Guarantee Deposit

If the provision of Service by FortisBC to a non-residential Customer will require construction and installation costs by FortisBC of more than $5,000 per Customer supplied, FortisBC may require each such Customer to provide a revenue guarantee deposit, as assurance that FortisBC will receive sufficient revenue to recover the installation costs of the facilities.

FortisBC will repay 20 percent of the revenue guarantee to the Customer at the end of each Year of Service, for a period of five Years, provided that the Customer's bills are paid in full at the time the refund is due. Interest will be paid on refunds as calculated in Section 8.8 (Payment of Interest).

If the contract for Service is terminated prior to five Years from the date of installation, any balance of the revenue guarantee remaining will belong to FortisBC absolutely as part of the consideration for FortisBC installing Service.

4.7 Limitation of Use

Service supplied to a Customer will be for the use of that Customer only and for the purpose applied for, and will not be remetered, submetered or resold to others except with the written consent of FortisBC or as provided in the applicable Rate Schedule.

5. SERVICE CHARACTERISTICS

5.1 Voltages Supplied

FortisBC will supply nominal 60 cycle alternating electric current to the Point of Delivery at the available phase and voltage.

Before wiring Premises or purchasing any electrical equipment, the Customer should consult with FortisBC to ascertain what type of Service may be available at the requested location. The Customer should present a description of the load to be connected so that FortisBC can furnish information regarding voltage and phase characteristics available at the Point of Delivery.

FortisBC will not supply transformation from one Secondary Voltage to another Secondary Voltage.

FortisBC reserves the right to determine the voltage and amperage of the Service connection.

5.1.1 Nominal Standard Secondary Voltage from Pole-Mounted Transformers

Single phase	120/240 volts 3 wire maximum 400 amperes.
Three phase	120/208 volts; 4 wire; 300 kVA maximum transformation capacity
	347/600 volts; 4 wire; maximum 300 kVA transformation capacity.

5.1.2 Nominal Standard Secondary Voltage from Pad-Mounted Transformers

Single phase:	120/240 volts; 3 wire; maximum 600 amperes.
Three phase:	120/208 volts; 4 wire; maximum 500 kVA transformation capacity.
	347/600 volts; 4 wire; maximum 2,500 kVA transformation capacity.

5.1.3 Special Conditions

Special arrangements may be required under the following conditions:

(a) For Customer loads or supply voltages different from those listed above with pole-mounted and pad-mounted transformer installations, the Customer will be required to supply its own transformers and take Service at the available Primary Voltage;

(b) Customers initiating an upgrade of existing facilities using non standard Secondary Voltages may be required to upgrade to standard voltages at their own expense;

(c) Where a Customer has been required to supply its own transformation, transformation discounts will only be applicable if available under the existing Rate Schedule to which Service is provided to the Customer.

5.2 Customer Owned Equipment

All Customer owned transformers and equipment used to connect them to FortisBC's electrical system will be approved by and installed in a manner satisfactory to FortisBC.

Where a Customer supplies their own transformation from the primary distribution voltage, the rate for Large Commercial Service and Industrial Service will apply.

5.3 Motor Specifications

Single phase motors rated larger than two hp and other equipment with rated capacity greater than 1,650 watts will not be used on 120 volt circuits, unless otherwise authorized by FortisBC.

Motors of 20 hp or larger will be equipped with reduced voltage starters or other devices approved by FortisBC to reduce starting current, unless otherwise authorized by FortisBC.

5.4 Space Heating Specifications

5.4.1 Residential

The maximum capacity of residential heating units to be controlled by one switch or thermostat will be 6,000 watts. Where applicable, time delay equipment must be installed so that each of the heating units, as required, is energized sequentially at minimum intervals of ten seconds.

Heating units will be connected so as to balance as nearly as possible the current drawn from the circuits at the Point of Delivery.

5.4.2 Industrial

The maximum capacity of industrial heating units to be controlled by one switch or thermostat will be ten kW for single phase and 25 kW for three-phase units.

5.5 Water Heating Specifications

The heating units will be of non-inductive design for a nominal voltage of 240 volts unless otherwise agreed to by FortisBC, but units of less than 1,650 watts may have a nominal voltage of 120 volts.

Installations may consist of either one or two-unit heaters. In the single unit heater tank, the unit will be placed to heat the entire tank. In the two-unit heater tank, a "base" unit heater will be placed to heat the entire tank and a "booster" unit heater placed to heat not more than the top third of the tank.

Each unit heater will be controlled by a separate thermostat and will not exceed 6,000 watts, except heating units installed in tanks of 350 litres and larger may, at FortisBC's option, exceed 6,000 watts but will not exceed 17 watts per litre for either "base" or "booster" unit heater.

Thermostats must be permanently connected so that both heating units cannot operate at the same time except on tanks where the installed capacity does not exceed 6,000 watts.

FortisBC, may at its expense, install a time switch, carrier current control, or other device to limit the Hours of Service to the water heater. The period or periods each Day during which Service may be so limited will not exceed a total of two Hours.

6. TYPE OF SERVICE

6.1 Temporary Service

Where FortisBC has facilities available, Temporary Service may be supplied under any Rate Schedule applicable to the class of Service required. The Customer Charge or minimum set forth in that Rate Schedule will be applicable to the temporary Service, but in no case will it be less than one full Month.

6.1.1 Temporary to Permanent Service

The Customer will pay for the cost of the installation of a Temporary Drop Service of less than 30 meters over private property as prescribed in Section 17.1 (Installation of New/Upgraded Services) plus the charge for conversion to permanent Service as prescribed in Section 17.3 (Miscellaneous Standard Charges) provided the Temporary Service can be converted to the permanent Service at little additional cost.

6.1.2 Salvage of Temporary Service

If the Temporary Service cannot be used to form the permanent Service and must be removed, the Customer will pay for the cost of the installation of a Temporary Drop Service of less than 30 meters over private property as prescribed in Section 17.1 (Installation of New/Upgraded Services) plus the charge for salvage of the Temporary Service as prescribed in Section 17.3 (Miscellaneous Standard Charges). Following salvage of the Temporary Service, the Customer will pay for the installation of a permanent Drop Service as prescribed in Section 17.1 (Installation of New/Upgraded Services).

6.2 Underground Service

FortisBC's Tariff is designed to recover the cost of providing Service from overhead poles and conductors. A Customer applying for underground Service under any Rate Schedule will be responsible for actual costs greater than the connection of a Drop Service as specified in Section 4.5 (Customer Contributions).

6.2.1 Conditions of Underground Service

A Customer applying for underground Service agrees as follows:

(a) FortisBC will own, install and maintain the underground Service line to the Point of Delivery. The Customer will own, install and maintain the underground Service line beyond the Point of Delivery.

(b) The underground installation must comply with FortisBC's underground distribution standards.

(c) FortisBC will not be responsible for any loss or damage beyond the reasonable control of FortisBC due to the installation, operation or maintenance of the underground circuit.

6.3 Residential Service

Residential Service is normally single phase 120/240 volt. In FortisBC's discretion, three phase Residential Service or single phase Residential Service in excess of 200 amperes may be provided under special contract terms requiring the Customer to pay all additional costs of a larger Service.

At FortisBC's option, for billing purposes multiple family dwellings used exclusively for living quarters and served through one meter, may have the kilowatt-hour blocks and customer charge increased in proportion to the number of single family living quarters served.

6.3.1 Partial Commercial Use

Where a partial Commercial use is carried on in a Residential Premises (with or without outbuildings) and the Commercial area is separately metered, the Commercial area only may be on the applicable Commercial Service rate. If new buildings are erected or major alterations are made to a Premises with partial Commercial use, the Customer may be required to arrange the wiring to provide for separate metering.

6.3.2 Other Use

Where water pumps supply single family residences, the water pumps will be on the Residential Service rate provided they can be supplied single phase and total 5 HP or less.

6.3.3 Farms

Farm residences and their outbuildings will qualify for the exempt Residential Service rate provided the farm is assessed for property tax purposes as agricultural land and the Service is used primarily for the production of food or industrial crops on that land. Other use for commercial or non-farm purposes will be billed on the Commercial Service rate.

7. METER SETS AND METERING

7.1 Installation

FortisBC will provide all meters necessary for measuring the Customer's use of the electric Service provided by FortisBC. The meters will remain the property of FortisBC and will be maintained in accurate operating condition in accordance with the regulations of Measurement Canada.

The Customer may furnish, install and maintain, at their own expense, a meter system to verify the accuracy of FortisBC's meter system. The Customer's meter system and the manner of its installation will be approved by FortisBC.

7.2 Protection of Equipment

The Customer will exercise all reasonable diligence to protect FortisBC's meter from damage or defacement and will be held responsible for any costs of repair or cleaning resulting from defacement or damage.

7.3 No Unauthorized Changes

All connections and disconnections of electric Service and installation and repair of FortisBC's meter system will be made only by FortisBC. All meters will be sealed by FortisBC. Breaking the seals or tampering with the meter or meter wiring is unlawful and may be cause for Termination of Service by FortisBC, and may result in criminal charges for theft of Electricity.

7.4 Location

The Customer will provide a Service entrance and meter socket location in accordance with FortisBC requirements, and where required a metering equipment enclosure.

The meter socket will be located on an outside wall and be within 1 m. of the corner nearest the point of supply except, in the case of metering over 300 volts, the meter socket will be installed on the load side of the Service box and will be accessible to FortisBC personnel. All sockets must be installed between 1.4 m. and 1.7 m. above final grade to the centre of the meter. Meters will not be installed in carports, breezeways or similar areas. Any exceptions must be approved by FortisBC.

Meters will be installed in places providing safe and reasonable access. Meters will not be exposed to live steam, corrosive vapours or falling debris. Where the meter is recessed in the wall of a building, sufficient clearance must be provided to permit removal and testing of FortisBC equipment. The full cost of relocating an inaccessible meter will be borne by the Customer.

7.5 Meter Tests or Adjustments

A Customer may request in writing a test of the accuracy of a meter. The Customer will deposit an amount as provided in Section 17.3 (Miscellaneous Standard Charges) and FortisBC will remove the meter within 10 Days and apply to the authorized authority to have the meter tested. If the meter fails to meet any of the applicable laws and regulations, the deposit will be refunded to the Customer. If the meter is found to satisfy the applicable laws and regulations, the Customer will forfeit the deposit.

If after testing the meter is found not to be registering within the limits allowed by Measurement Canada, bills will be adjusted as prescribed in the applicable laws and regulations. If a refund is necessary, it will be calculated in accordance with Section 8.8 (Payment of Interest).

7.6 Metering Selection

Meters will be selected at FortisBC's discretion and will be compliant with the regulations of Measurement Canada. FortisBC, at its discretion, may change the type of metering equipment.

7.7 Unmetered Service

FortisBC may permit unmetered Service if it can estimate to its satisfaction the energy used based on the connected load and Hours of use. Customers served under this provision must notify FortisBC immediately of any proposed or actual changes in load or Hours of use. FortisBC, at its discretion, may at any time require the installation of a meter or meters and thereafter bill the Customer on the consumption registered.

8. BILLING

8.1 Basis for Billing

FortisBC will bill the Customer in accordance with the Customer's Service Agreement, the Rate Schedule under which the Customer is provided Service, and the fees and charges contained in Section 17 (Standard Charges Schedule).

The Customer will pay for Electricity in accordance with these General Terms and Conditions and the Customer's applicable Rate Schedule, as amended from time to time and accepted for filing by the British Columbia Utilities Commission. If it is found that the Customer has been overcharged, the appropriate refund will be with interest as calculated in Section 8.8 (Payment of Interest).

8.2 Payment of Accounts

Bills for electric Service are due and payable when rendered. Payments may be made to FortisBC's collection office, electronically or to authorized collectors.

8.2.1 Customer Selected Bill Date

Customers will be permitted to select a bill date under the following conditions:

(a) The Customer is served with a meter with the integrated wireless transmit functions enabled and the meter is not currently manually read; and

(b) The Customer's account is not in arrears.

FortisBC will render bills to the Customer on or as close to the Customer selected bill date as possible. FortisBC, at its sole discretion, may refuse a Customer request to change a bill date.

8.2.2 Late Payments

A Customer's account, including the account under a Financing Agreement, not paid by the due date printed on the bill will be in arrears. Late payment charges may be applied to overdue accounts at the rate specified on the bill and as set out on the applicable Rate Schedule.

Customers will be advised that their account is in arrears by way of notification on the next billing. If payment is not received, a letter will be mailed to the Customer advising that if payment is not received within ten Days of the date of mailing, Service may be suspended without further notice. FortisBC will make every reasonable effort to contact the Customer by telephone or in person to advise the Customer of the consequences of non-payment, but the account may be disconnected if payment is not received.

8.2.3 Sales Tax and Assessments

In addition to payments for Services provided, the Customer will pay to the Company the amount of any taxes or assessments imposed by any competent taxing authority on any Services provided to the Customer.

8.2.4 Historical Billing Information

Customers who request historical billing information may be charged the cost of processing and providing the information.

8.3 Meter Reading

Meters will be read at the end of each billing period in accordance with the applicable Rate Schedule. The interval between consecutive meter readings will be determined by FortisBC. An accurate record of all meter readings will be kept by FortisBC and will be the basis for determination of all bills rendered for Service.

8.4 Estimates

Where an accurate meter reading cannot be obtained due to meter failure, temporary inaccessibility, or any other reason, Electricity delivered to the Customer will be estimated by FortisBC from the best available sources and evidence. Where the Customer requests Termination of Service pursuant to Section 3.4 (Termination of Service Agreement), FortisBC may estimate the final meter reading for final billing.

8.5 Proration of Billing

Bills will be prorated as appropriate under the following conditions:

(a) For meters normally read every one Month where the billing period is less than 21 Days or greater than 39 Days.

(b) For meters normally read every two Months where the billing period is less than 51 Days or greater than 69 Days.

8.6 Equal Payment Plan

Upon application, FortisBC may permit qualifying Residential Customers to pay their accounts in equal Monthly payments. The payments will be calculated to yield, over a twelve Month period, the total estimated amount that would be payable by the Customer calculated by applying the applicable Residential Service rate to the Customer's estimated consumption during the same twelve Month period. Customers may make application at any time of the year. All accounts will be reconciled annually or the earlier Termination date, at which time the amounts payable by the Customer to FortisBC for Electricity actually consumed during the equal payment period will be compared to the sum of equal payments made during the period. Any resulting amount owing by the Customer will be paid to FortisBC.

A Residential Customer may qualify for the plan provided their account is not in arrears, they have established credit to the satisfaction of FortisBC and the Customer expects to be on the equal payment plan for at least one Year.

FortisBC may at any time revise the equal Monthly installments to reflect changes in estimated consumption or the applicable Rate Schedule.

The equal payment plan may be terminated by the Customer upon reasonable notice, or by FortisBC if the Customer has not maintained their credit to the satisfaction of FortisBC. FortisBC reserves the right to cancel or modify the Equal Payment Plan Service at any time.

If a Customer on an equal payment plan has a credit balance and closes the account, FortisBC will refund the amount regardless of the size of the balance. If the Customer has not terminated their account, and the credit balance is small, it will be carried forward.

8.7 Back-billing

8.7.1 When Required

FortisBC may, in the circumstances specified in this Section 8.7 (Back-billing) charge, demand, collect, or receive from its Customers in respect of a regulated Service rendered to its Customers a greater or lesser compensation than that specified in the Rate Schedules applicable to that Service.

In the case of a minor adjustment to a Customer’s bill, such as an estimated bill or a Monthly Payment Plan bill, such adjustments do not require back-billing treatment to be applied.

8.7.2 Definition

Back-billing means the rebilling for Services rendered to a Customer because the original billings are discovered to be either too high (over-billed) or too low (under-billed). The discovery may be made by either the Customer or FortisBC, and may result from the conduct of an inspection under provisions of the federal statute, the EGI Act. The cause of the billing error may include any of the following non-exhaustive reasons or combination thereof:

(a) Stopped meter.
(b) Metering equipment failure.
(c) Missing meter now found.
(d) Switched meters.
(e) Double metering.
(f) Incorrect meter connections.
(g) Incorrect use of any prescribed apparatus respecting the registration of a meter.
(h) Incorrect meter multiplier.
(i) The application of an incorrect rate.
(j) Incorrect reading of meters or data processing.
(k) Tampering, fraud, theft or any other criminal act.

8.7.3 Application of Act

Whenever the dispute procedure of the EGI Act is invoked, the provisions of that Act apply, except those which purport to determine the nature and extent of legal liability flowing from metering or billing errors.

8.7.4 Billing Basis

Where metering or billing errors occur and the dispute procedure under the EGI Act is not invoked, the consumption and Demand will be based upon the records of FortisBC for the Customer, or the Customer's own records to the extent they are available and accurate, or if not available, reasonable and fair estimates may be made by FortisBC. Such estimates will be on a consistent basis within each Customer class or according to a contract with the Customer, if applicable.

8.7.5 Tampering / Fraud

If there are reasonable grounds to believe that the Customer has tampered with or otherwise used FortisBC's Service in an unauthorized way, or there is evidence of fraud, theft or other criminal acts, or if a reasonable Customer should have known of the under-billing and failed to promptly bring it to the attention of FortisBC, then the extent of back-billing will be for the duration of unauthorized use, subject to the applicable limitation period provided by law and the provisions of Sections 8.7.8 (Under-billing) to 8.7.11 (Changes in Occupancy), below do not apply.

In addition, the Customer is liable for the administrative costs incurred by FortisBC in the investigation of any incident of tampering, including the direct costs of repair, or replacement of equipment.

Under-billing resulting from circumstances described above will bear interest at the rate normally charged by FortisBC on unpaid accounts from the date of the original under-billed invoice until the amount underbilled is paid in full.

8.7.6 Remedying Problem

In every case of under-billing or over-billing, the cause of the error will be remedied without delay, and the Customer will be promptly notified of the error and of the effect upon the Customer's ongoing bill.

8.7.7 Over-billing

In every case of over-billing, FortisBC will refund to the Customer all money incorrectly collected for the duration of the error, subject to the applicable limitation period provided by law. Interest will be paid in accordance with Section 8.8 (Payment of Interest).

8.7.8 Under-billing

Subject to Section 8.7.5 (Tampering / Fraud) above, in every case of under-billing, FortisBC will back-bill the Customer for the shorter of:

(a) the duration of the error; or

(b) six Months for Residential, Commercial Service, Lighting and Irrigation; and

(c) one Year for all other Customers or as set out in a special or individually negotiated contract with FortisBC.

8.7.9 Terms of Repayment

Subject to Section 8.7.5 (Tampering / Fraud) above, in all cases of under-billing, FortisBC will offer the Customer reasonable terms of repayment. If requested by the Customer, the repayment term will be equivalent in length to the back-billing period. The repayment will be interest free and in equal installments corresponding to the normal billing cycle. However, delinquency in payment of such installments will be subject to the usual late payment charges.

8.7.10 Disputed Back-bills

Subject to Section 8.7.5 (Tampering / Fraud) above, if a Customer disputes a portion of a back-billing due to under-billing based upon either consumption, Demand or duration of the error, FortisBC will not threaten or cause the discontinuance of Service for the Customer's failure to pay that portion of the back-billing, unless there are no reasonable grounds for the Customer to dispute that portion of the back-billing. The undisputed portion of the bill will be paid by the Customer and FortisBC may threaten or cause the discontinuance of Service if such undisputed portion of the bill is not paid.

8.7.11 Changes in Occupancy

Subject to Section 8.7.5 (Tampering / Fraud) above, back-billing in all instances where changes of occupancy have occurred, FortisBC will make a reasonable attempt to locate the former Customer. If, after a period of one Year, such Customer cannot be located, the over- or under-billing applicable to them will be canceled.

8.8 Payment of Interest

When interest is to be applied to certain Customer payments as provided in these General Terms and Conditions, it will be calculated as follows:

FortisBC will pay simple interest at the average prime rate of the principal bank with which FortisBC conducts its business, commencing with the date the subject funds were received by FortisBC.

The interest will be remitted to the Customer at the time the deposit or other payments are refunded, or in the case when a deposit or other refundable payment is to be held beyond one Year, the interest will be calculated once every 12 Months and will be applied to the Customer's account.

9. LOAD CHANGES AND OPERATION

9.1 Notice by Customer

A Customer will give to FortisBC reasonable written notice of any change in its load requirements to permit FortisBC to determine whether or not it can meet the requirements without changes to its equipment or system.

Notwithstanding any other provision of these General Terms and Conditions, FortisBC will not be required to supply to any Customer Electricity in excess of that previously agreed to by FortisBC.

Customers with a Demand component in the Rate Schedule who wish to change the Contract Demand or the Demand limit, will submit to FortisBC a written request subject to the following provisions;

(a) an increase requested of less than 1,000 kVA will be submitted not less than three Months in advance of the date the increase is intended to become effective; and

(b) an increase requested in excess of 1,000 kVA but less than 5,000 kVA will be submitted not less than one Year in advance of the date the increase is intended to become effective;

(c) an increase requested in excess of 5,000 kVA will be submitted not less than three Years in advance of the date the increase is intended to become effective; and

(d) a decrease requested of up to 10 percent per Year of the existing Contract Demand or Demand limit will be submitted not less than three Months in advance of the date the decrease is intended to become effective. Customers with a Contract Demand in excess of 500 kVA will provide FortisBC by January 31 of each year their best estimate of their annual Electricity requirements to allow FortisBC to forecast future load on its facilities.

If FortisBC approves the request in writing, the Contract Demand or the Demand limit may be changed either by amendment to the Customer's contract or by the parties executing a new contract. FortisBC will not be required to approve any requested change in the Contract Demand or the Demand limit.

9.2 Changes to Facilities

The Customer may be required to pay for the cost of any alterations to FortisBC's facilities necessary to provide the Customer's increased load. If any increase in load, Contract Demand or Demand limit, approved by FortisBC, requires it to add to its existing facilities for the purpose of complying with the Customer's request, the approved increase will be subject to payment of a Customer contribution under Section 4.5 (Customer Contributions). The Customer may also be required to provide a revenue guarantee deposit as set out in Section 4.6 (Revenue Guarantee Deposit).

9.3 Responsibility for Damage

A Customer will be responsible for and pay for all damage caused to FortisBC's facilities as a result of that Customer increasing its load without the consent of FortisBC.

The Customer will indemnify FortisBC for all costs, damages, or losses arising from the Customer exceeding its Demand limit, including without limiting generality, direct or consequential costs, damages or losses arising from any penalty incurred by FortisBC for exceeding its Demand limit with its suppliers of Electricity.

9.4 Power Factor

Customers will regulate their loads to maintain a Power Factor of not less than 90 percent lagging or as otherwise provided for in the applicable Rate Schedule. If the Power Factor of the Customer's load is less than the minimum required, the Customer's bill may be increased by an adjustment for low Power Factor. FortisBC may also require the Customer, at its expense, to install Power Factor corrective equipment to maintain the minimum required Power Factor.

FortisBC may refuse Service for neon, mercury vapour, fluorescent or other types of outdoor lighting or display device which has a Power Factor of less than 90 percent or other detrimental characteristics.

No credit will be given for leading Power Factor.

9.5 Load Fluctuations

The Customer will operate its motors, apparatus and other electrical equipment in a manner that will not cause sudden fluctuation to FortisBC's line voltage, or introduce any element into FortisBC's system that, in FortisBC's opinion, disturbs or threatens to disturb its electrical system or the property or Service of any other Customer. Under no circumstances will the imbalance in current between any two phases be greater than five percent. The Customer will indemnify FortisBC against any liability, loss, cost and expense occasioned by the Customer's failure to operate its electrical equipment in compliance with this section.

10. CONTINUITY OF SERVICE

10.1 Interruptions and Defects in Service

FortisBC will endeavour to provide a regular and uninterrupted supply of Electricity but it does not guarantee a constant supply of Electricity or the maintenance of unvaried frequency or voltage and will not be responsible or liable for any loss, injury, damage or expense caused by or resulting from any interruption, Suspension, Termination, failure or defect in the supply of Electricity, whether caused by the negligence of FortisBC, its servants or agents, or otherwise unless the loss, injury, damage or expense is directly resulting from the willful misconduct of FortisBC, its servants or agents provided, however, that FortisBC, its servants and agents are not responsible for any loss of profit, loss of revenues or other economic loss even if the loss is directly resulting from the willful misconduct of FortisBC, its servants or agents.

All responsibility of FortisBC for Electricity delivered to the Customer will cease at the Point of Delivery, and the Customer will indemnify FortisBC and save it harmless from all liability, loss and expense caused by or arising out of the taking of Electricity by the Customer.

The expense of any interruption of Service to others, loss of or damage to the property of FortisBC through misuse or negligence of the Customer, or the cost of necessary repairs or replacement will be paid to FortisBC by the Customer.

10.2 Refusal of Service and Suspension of Service

FortisBC may refuse Service or demand Suspension of Service if, in the opinion of FortisBC:

(a) conditions other than standard conditions are required by the applicant;
(b) facilities are not available to provide adequate Service;
(c) the Customer's facilities are not satisfactory to FortisBC;
(d) the applicant or owner or occupant of the Premises has an unpaid account for Service or an unpaid amount under a Financing Agreement;
(e) the Customer or applicant occupies the Premises with another occupant who has failed to pay FortisBC's bill, security deposit, or required increase in the security deposit in respect of another Premises that was occupied by that occupant and the Customer at the same time;
(f) the Customer or applicant has provided false or misleading information;
(g) the Customer or applicant is not the owner or occupant of the Premises;
(h) the Customer has failed to apply for Service;
(i) the Service requested is already supplied to the Premises for another Customer who does not consent to having the Service terminated;
(j) the applicant cannot provide satisfactory security for payment as required by FortisBC;

(k) the applicant is in receivership or bankruptcy, or operating under the protection of insolvency legislation and has failed to pay any outstanding bills to FortisBC; or

(l) the applicant has breached any agreement or terms with FortisBC.

The Company will not be liable for any loss, injury or damage suffered by any Customer by reason of a refusal to provide Service.

10.2.1 Suspension of Service for Safety, Repairs or Maintenance

FortisBC and the Customer may demand the Suspension of Service whenever necessary to safeguard life or property, or for the purpose of making repairs on or improvements to any of its apparatus, equipment or work. Such reasonable notice of the Suspension as the circumstances permit will be given.

The Company may suspend Service to the Customer for the failure by the Customer to take remedial action acceptable to FortisBC, within 15 Days of receiving notice from FortisBC, to correct the breach of any provision of these General Terms and Conditions to be observed or performed by the Customer. FortisBC will be under no obligation to resume Service until the Customer gives assurances satisfactory to FortisBC that the breach which resulted in the Suspension will not recur.

FortisBC will have the right to suspend Service to make repairs or improvements to its electrical system and will, whenever practicable, give reasonable notice to the Customer.

10.2.2 Suspension of Service Without Notice

FortisBC will have the right to suspend or terminate Service at any time without notice for any of the following reasons:

(a) the Customer has breached any agreement, including provisions of a Financing Agreement, with FortisBC;

(b) the Customer has failed to pay arrears within the specified time

(c) the Customer has fraudulently used the Service;

(d) the Customer has tampered with FortisBC's equipment or committed similar actions;

(e) the Customer has compromised FortisBC’s Service to other Customers; or

(f) FortisBC is ordered by an authorized authority to suspend or terminate such Service.

The cause of any Suspension must be corrected, and all applicable charges paid before Service will be resumed.

Suspension of Service by FortisBC will not operate as a cancellation of any contract with FortisBC, and will not relieve any Customer of its obligations under these General Terms and Conditions or the applicable Rate Schedule.

11. RIGHTS-OF-WAY AND ACCESS TO FACILITIES

11.1 Rights-of-Way

By applying for electric Service, the Customer agrees to grant to FortisBC such rights-of-way, easements and any applicable permits on, over and under the property of the Customer as may be necessary for the construction, installation, maintenance or removal of facilities.

On request, the Customer, at their own expense, will deliver to FortisBC documents satisfactory to FortisBC in registrable form granting the rights-of-way, easements and executed permits. The Customer will, at their own expense, be responsible for obtaining rights-of-way, easements and any applicable permits on other properties necessary for FortisBC to provide Service to the Customer.

Notwithstanding payment by the Customer towards the cost of electrical facilities installed by FortisBC or that electrical facilities may be affixed to the Customer's property, all electrical facilities installed by FortisBC up to the Point of Delivery will remain the property of FortisBC, and FortisBC will have the right to safe and ready access to upgrade, renew, replace or remove any facilities on the Customer's property at any time.

11.2 Access

FortisBC, through its authorized employees and agents, will have safe and ready access to its electrical facilities at all reasonable times for the purpose of reading meters and testing, installing, removing, repairing or replacing any equipment which is the property of FortisBC. If access is restricted, FortisBC will be supplied with keys to such locks if requested or, at FortisBC's option, a key holder box, where such locations are unattended during reasonable times.

In no case will FortisBC accept keys to private residential properties.

If safe and ready access to FortisBC's electrical facilities is denied or obstructed in any manner, including the presence of animals, and the Customer takes no action to remedy the problem upon being so advised, Service will be suspended and not reconnected until the problem is corrected. In cases where the Customer does not provide FortisBC with safe and ready access to the meter, FortisBC may install a remote meter. The Customer will be responsible for the cost of the remote meter and its installation as set out under the Meter Access Charge in Section 17 (Standard Charges).

Where FortisBC uses radio-frequency technology to remotely communicate with its meters or other infrastructure owned and maintained by FortisBC, the Customer is responsible for ensuring no device or obstruction is placed on or near FortisBC's equipment for the purpose of interfering, attenuating or degrading the signal.

If a FortisBC representative attends a Customer's Premises at the request of a Customer but on attending the Customer refuses access, or the FortisBC representative is unable to perform the requested work because the facilities required to be provided by the Customer for this purpose are found to be deficient a False Site Visit Charge per occurrence may be levied as set out in Section 17.3 (Miscellaneous Standard Charges).

11.3 Exception

Notwithstanding the provisions of Section 11.1 (Rights-of-Way) and Section 11.2 (Access), approval of the B.C. Utilities Commission will be required prior to any removal of plant constructed to serve industrial Customers supplied at 60 kV and above.

12. CUSTOMER-OWNED GENERATION

12.1 Parallel Generation Facilities

A Customer may, at their own expense, install, connect and operate their own electrical generating facilities to its electrical circuit in parallel with FortisBC's electrical system provided that the manner of installation and operation of the facilities is satisfactory to FortisBC, and the facilities have the capacity to be immediately isolated from FortisBC's system in the event of disruption of Service from FortisBC.

Prior to the commencement of installation of any generating facilities, the Customer will provide to FortisBC full particulars of the facilities, and the proposed installation, and will permit FortisBC to inspect the installation. The Customer, at its own expense, will provide approved synchronizing equipment before connecting parallel generating facilities to the FortisBC electrical system.

The Customer's generating facilities will not be operated in parallel with FortisBC's electrical system until written approval has been received from FortisBC. The Customer will not modify its parallel facilities or the installation in any manner without first obtaining the written approval of FortisBC.

If at any time FortisBC's electrical system is adversely affected due to difficulties caused by the Customer's generating facilities, upon oral or written notice being given by FortisBC to a responsible employee of the Customer, the Customer will immediately discontinue parallel operation, and FortisBC may suspend Service until such time as the difficulties have been remedied to the satisfaction of FortisBC.

The Customer will be responsible for the proper installation, operation and maintenance of all protective and control equipment necessary to isolate the Customer's generating facilities from FortisBC's electrical system upon the occurrence of a fault on the Customer's generating facilities or FortisBC's electrical system. The Customer's protective equipment will not be modified in any manner and the settings thereto will not be changed without first obtaining written approval of FortisBC.

The Customer will notify FortisBC in advance each and every time that the Customer's generating facilities are to be connected to or intentionally disconnected from FortisBC's electrical system.

During parallel operation of its generating facilities, the Customer will cooperate with FortisBC so as to maintain the voltage and the Power Factor of Electricity at the Point of Delivery within limits agreeable to FortisBC and as set out in Section 9.4 (Power Factor), and will take and use Electricity in a manner that does not adversely affect FortisBC's electrical system.

Notwithstanding any approval given by FortisBC, parallel operation of the Customer's generating facilities with FortisBC's electrical system will be entirely at the risk of the Customer, and the Customer will indemnify FortisBC and save it harmless from all injury, damage and loss and all actions, suits, claims, demands and expenses caused by or in any manner arising out of the operation of the Customer's generating facilities.

12.2 Standby Generation

A Customer may, at their own expense, install standby generation facilities to provide electrical Service in the event of a disruption of Service from FortisBC. Standby generation facilities will be installed so that they remain at all times electrically isolated from FortisBC's electrical system either directly or indirectly, and will be installed in such a way that it is not possible for the facilities to operate in parallel with FortisBC's electrical system.

The Customer's standby electrical generating facilities will not be operated without the prior inspection and written approval of FortisBC, and the facilities will not be modified thereafter without the written approval of FortisBC.

12.3 Electrical Inspection Authority

The Customer must obtain the approval of the appropriate electrical inspection authority before installation.

13. GENERAL PROVISIONS

13.1 Notices

Any notice, direction or other instrument will be deemed to have been received on the following dates:

(a) if sent by electronic transmission, on the Business Day next following the date of transmission;

(b) if delivered, on the Business Day next following the date of delivery;

(c) if sent by registered mail, on the fifth Business Day following its mailing, provided that if there is at the time of mailing or within two Days thereafter a mail strike, slowdown, lockout or other labour dispute which might affect delivery, then any notice, direction or other instrument will only be deemed to be effective if delivered or sent by electronic transmission.

13.2 Conflicts

In case of conflict between these General Terms and Conditions and the Rate Schedules, the provisions of the Rate Schedules will prevail. Where there is a conflict between a contract and these General Terms and Conditions, the provisions of the contract will apply.

13.3 Force Majeure

If any Large Commercial Service Rate Schedule Customer is prevented from taking Electricity, except for emergency purposes, for a period in excess of five calendar Days by damage to its works from fire, explosion, the elements, sabotage, act of God or the Queen's enemies, or from insurrection, strike, or difficulties with workmen and invokes force majeure, FortisBC will not be bound to make Electricity available during the period of the interruption except for emergency purposes, and commencing on the sixth calendar Day of the interruption but for not more than 25 calendar Days, the Customer will, in lieu of the Demand Charge stipulated in the applicable Large Commercial Service Rate Schedule, pay a reduced Demand Charge for the period of the interruption, commencing on the sixth calendar Day of the interruption to a maximum of 25 calendar Days, derived from the Demand Charge rate multiplied by the maximum Demand recorded during that period of the interruption. The Customer will not be entitled to any adjustment in the monthly Demand Charge under this clause unless the Customer informs FortisBC in writing it is invoking this clause, and FortisBC will read the meters used for billing purposes at the end of the fifth Day of interruption and at the end of the period of interruption. The Customer will be prompt and diligent in removing the cause of the interruption (by restoring its works or such other action as may be necessary and as soon as the cause of the interruption is removed or ceases to exist FortisBC will without delay make Electricity available and the Customer will take and pay for the same in accordance with this Tariff.

The force majeure provisions of this Clause 11.4 will not apply in any Month in which FortisBC purchases Electricity from British Columbia Hydro and Power Authority, unless FortisBC and British Columbia Hydro and Power Authority agree to a force majeure provision, in which case the Customer will be given relief from the Demand Charge in accordance with that agreement.

14. REPAYMENT OF ENERGY MANAGEMENT INCENTIVES

For those Customers supplied under Large Commercial Service or Wholesale Rate Schedules or Customers with a Contract Demand of 300 kVA or more, the unamortized balance of financial incentives paid to the Customer under Rate Schedule 90 will be remitted to FortisBC within 30 Days of billing, if:

(a) the operations at the Customer site are reduced by more than 50% for a continuous period of three Months or longer; or

(b) over 50% of the Electricity previously provided by FortisBC is replaced by another source including self-generation or another supplier.

In both cases the repayment will be prorated based on the amount of energy replaced compared to the amount of energy supplied by FortisBC in the year immediately preceding the Electricity replacement.

15. ENERGY EFFICIENCY IMPROVEMENT FINANCING

Pursuant to section 17.1 of the *Clean Energy Act* and the *Improvement Financing Regulation*, for a two-year period beginning November 1, 2012 and ending January 1, 2015, FortisBC offers a Loan to eligible Customers located in the City of Kelowna and Regional District of Okanagan-Similkameen, excluding the City of Penticton and District of Summerland for energy efficiency improvements to an eligible Premises, or a part of an eligible Premises. The terms and conditions under which financing is offered are contained in Electric Tariff Rate Schedule 91.

16. EXTENSIONS

16.1 Ownership and Maintenance

FortisBC will assume ownership and maintenance of an Extension on public or private property upon connection of the Extension to FortisBC's distribution system.

16.2 Application Requirements

FortisBC will commence construction of an Extension or authorize the connection or disconnection of an Extension constructed by a FortisBC pre-approved contractor once the following conditions have been met:

(a) The applicant for an Extension has completed a contract for Service as required under Section 2 (Application for Service) and any other required documentation;

(b) The applicant has obtained all necessary easements, permits, or licences of occupation;

(c) Where applicable, construction of the new building has advanced to the point where completion seems assured, or the applicant has provided adequate security for the amount of FortisBC's investment; and

(d) the applicant has paid to FortisBC the full estimated CPC less any amount financed by FortisBC and less any amount agreed to by FortisBC pursuant to Section 16.3 (Customer Portion of Costs).

16.3 Customer Portion of Costs

16.3.1 FortisBC Contribution

FortisBC will contribute towards an Extension as follows, multiplied by the number of Customers to be served from the Extension:

Rate Schedule	Maximum FortisBC Contribution
Rate Schedule 1, 2A, 3A	$2,634
Rate Schedule 20, 21	$279 per kW
Rate Schedule 30	$121 per kW
Rate Schedule 50 (Type I, Type II)	$28.15 per fixture
Rate Schedule 60, 61	$3,543

The Applicant will pay the Customer Portion of Costs (CPC). The CPC is the estimated cost to construct the Extension less the FortisBC Contribution towards the Extension, and does not include any applicable connection charges as specified in Section 17 (Standard Charges). The CPC will be paid either in cash or, with FortisBC's agreement, wholly or partly in kind.

16.3.2 Refund of Customer Portion of Costs

FortisBC will have the right to connect additional Customers to an Extension. Additional Customers that take Service from an Extension within five Years of the connection of the Extension to FortisBC's distribution system will pay a share of the Extension Cost (less the FortisBC Contribution towards the Extension), without interest, in proportion to that part of the Extension that is used to provide Service and in proportion to the number of original Customers taking Service from the Extension.

No share of the Extension Cost will be paid where:

(a) the contribution would be less than $200.00 per Customer connected to the Extension; or

(b) more than five Years have passed from the date the Extension was connected to FortisBC's distribution system to the date of the connection of the additional Customer to the Extension.

A refund of the Extension Cost that has been received from an additional Customer connecting to the Extension will be made existing Customers on that Extension.

16.3.3 Financing

FortisBC financing is available to applicants for an Extension on approval of credit. The CPC will be financed based on FortisBC's weighted average cost of capital as approved by the British Columbia Utilities Commission. A downpayment of 20% of the CPC is required from each applicant. Financing is available for one to five Year terms for extensions costing over $2,000. FortisBC will finance a maximum of $10,000 per applicant.

16.3.4 Special Contracts

An applicant for an Extension may be required to make a contribution in addition to the CPC in the following circumstances:

(a) Where additional investment is required in order to upgrade or reinforce existing facilities or install new facilities to provide Service at a phase and voltage not presently available;

(b) For Large Commercial Service and Industrial Applicants, where installation and upgrading of substation and transmission facilities may be required; or

(c) For temporary or standby Service, where the Applicant may also be required to pay the cost of removal of the facilities.

In any of the the above circumstances, FortisBC may request the applicant for an Extension to enter into a special contract arrangement. The special contract may require the applicant to pay for Extension Costs and upgrades or reinforcements of existing facilities, and to pay for any replacements of the Extension that may be required.

16.4 Design and Construction Requirements

Extensions will normally be constructed overhead, but may be constructed underground where such construction is in accordance with FortisBC's distribution system plans or other constraints exist that require underground systems.

Extensions will be designed and constructed in accordance with FortisBC's distribution construction standards and material specifications.

16.5 Designing and Estimating

An applicant for an Extension may select FortisBC or a FortisBC pre-approved contractor to design and/or construct the Extension.

Where an applicant selects FortisBC to design and/or construct the Extension:

(a) Upon receipt of a request for Service requiring an Extension, FortisBC will engineer and design the Extension (Design Package), and provide a quote of the Extension cost (Estimate Package);

(b) The cost of preparing the Design Package, including the cost of any revisions to the Design Package that are requested by the applicant, will be borne by the applicant and will be paid upon receipt of the Design Package;

(c) Prior to the release of the Design Package and the Estimate Package, the Applicant may be required to sign a contract that includes terms and conditions relating to the construction of the Extension.

(d) FortisBC will construct the Extension at the cost quoted in the Estimate Package.

Where an applicant selects a FortisBC pre-approved contractor to design and/or construct the Extension:

(a)_ The Design Package will be engineered and designed to FortisBC standards, and FortisBC will provide an Estimate Package for FortisBC's costs;

(b) Prior to the connection of the Extension to FortisBC's distribution system, the applicant will pay to FortisBC all additional costs, estimated in advance by FortisBC and provided to the applicant in the Estimate Package, incurred for designing, engineering, surveying, obtaining permits, connecting to FortisBC's distribution system, and inspecting the Extension;

(c) FortisBC, in its sole discretion, may survey, at the cost of the applicant, Extensions designed and/or constructed by a FortisBC pre-approved contractor prior to connecting the Extension to FortisBC's distribution system.

16.6 Delay in Construction

Where Customer actions cause construction to be delayed by a period of 6 Months or greater after receipt of the CPC, FortisBC reserves the right to re-quote the CPC using current pricing, excluding any material(s) already purchased. Any additional costs must be paid by the Customer to FortisBC prior to the commencement of construction. Any resulting credit will be promptly refunded by FortisBC to the Customer.

16.7 Limitation on Work Done by FortisBC Pre-approved Contractors

A FortisBC pre-approved contractor may not work on any of FortisBC's electrical facilities, and FortisBC will make all connections to or disconnections from FortisBC's distribution system.

16.8 Easements and Right of Way Clearing

An applicant for an Extension will provide an easement for the Extension, including an easement for vehicle access to the Extension, that is acceptable to FortisBC. For Extensions to be constructed by FortisBC, such easement will be provided prior to the construction of the Extension. For all other Extensions, such easement will be provided prior to the connection of the Extension to FortisBC's distribution system.

The applicant will be responsible for all right of way clearing costs required for the construction of an Extension.

The Applicant will ensure that all right of way clearing is performed in accordance with FortisBC's distribution construction standards.

17. STANDARD CHARGES SCHEDULE

17.1 Installation of New/Upgraded Services

The minimum charge for the installation of a new or upgrading of an existing Service, including one meter, is as follows:

Overhead – Single Phase – 200 Amps or less	$739
Underground – Single Phase – 200 Amps or less	$804

For all other Service connections and a meter, the applicant will pay the Customer Portion of Costs of the Service connection as per Section 4.5 (Customer Contributions).

17.2 Connection Charges

Meter connection, or manual reconnection of a meter after disconnection for violation of the General Terms and Conditions in this Tariff, or Meter Test

Performed during regular working hours	$135
Performed during overtime hours	$224
Performed during callout hours	$462
Each additional Meter connection for one Customer at the same time at one location	$34
Remote reconnection of a meter after disconnection for violation of the General Terms and Conditions in this Tariff	$13
Disconnection and reconnection of meter	$271
Relocation of existing Service requiring a Service drop change on the same building during regular working hours	$902

17.3 Miscellaneous Standard Charges

Account Setup or Transfer	$13
Return Payment Charge	$13
Meter Access Charge – Single Phase Remote Meter	$206
Meter Access Charge – Poly Phase Remote Meter	$419
False Site Visit Charge	$246
Temporary to Permanent Service Charge	$267
Salvage of Temporary Service Charge	$267

17.4 Custom Work

FortisBC may recover the full cost of the following custom work:

(a) At the Customer's request, when a special trip is necessary to inspect a Service due to an outage and the fault is found to be beyond the Point of Delivery, FortisBC will be reimbursed for the full cost;

(b) Installation of facilities beyond those considered necessary by FortisBC in order to provide Service and not provided for elsewhere in FortisBC's tariff;

(c) Replacement or repair of facilities damaged by causes other than reasonable wear and tear;

(d) At the Customer's request, relocation of the Service to permit tree trimming, construction, etc., where recovery of the costs are not provided for in the standard charges above.

18. RADIO-OFF ADVANCED METER OPTION

18.1 Applicable To

A FortisBC Customer with a FortisBC-installed meter with integrated wireless transmit functions enabled, or a Customer scheduled by FortisBC to receive a meter with integrated wireless transmit functions enabled will apply for a Radio-off AMI Meter.

18.2 Application Requirements

Radio-off Customers will apply to FortisBC for a Radio-off AMI Meter consistent with the process required for a standard Application for Service as set out in Section 2 (Application for Service) of FortisBC's Electric Tariff General Terms and Conditions and will be provided with a meter that has the integrated wireless transmit functions disabled.

18.3 Conditions of Service

Radio-off Customers will pay the charges as set out in Section 18.4 (Radio-off Option Standard Charges). Failure to pay these charges will be subject to standard collection procedures and may result in the Discontinuance of Service. The Per-premise set up fee will be charged on the first bill after the Radio-off AMI Meter is installed, and the Per-Read fees will be charged on every subsequent bill.

If a Radio-off Customer elects to stop using the Radio-off AMI Meter Option, FortisBC will obtain a final manual meter read prior to enabling the integrated wireless transmit functions of the meter. The Radio-off Customer will incur one final Per-Read fee for this service.

18.4 Radio-off Option Standard Charges

Radio-off Customers will be charged the following by FortisBC for the Radio-off AMI Meter Option:

Per-Premise Setup Fee	$88
Per-Read Fee	$25

RATE SCHEDULE 1 - RESIDENTIAL SERVICE

APPLICABLE:	To residential use including service to incidental motors of 5 HP or less.
BIMONTHLY RATE:	First 1600 kW.h @ 10.394¢ per kW.h Additional kW.h @ 14.915¢ per kW.h plus:
CUSTOMER CHARGE:	$33.16 per two Month period
OVERDUE ACCOUNTS:	A late payment charge of 1 1/2 % will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.
NOTE:	For the purposes of Monthly billing the Customer Charge will be prorated on a Monthly basis and the threshold will be 800 kW.h per Month.
PERMANENT RATE ESTABLISHMENT:	Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 2 A - RESIDENTIAL SERVICE - TIME OF USE

APPLICABLE: To Residential use including service to incidental motors of 5 HP or less. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	22.435
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	11.869
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9.280

plus:

CUSTOMER CHARGE: $37.39 per two Month period

OVERDUE ACCOUNTS A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 3 A - EXEMPT RESIDENTIAL SERVICE

APPLICABLE: To residential use including service to incidental motors of 5 HP or less. For residential service and use exempted from Rate Schedule 1, including:

1. Farm Customers that qualify for Residential Service as set out in FortisBC's Electric Tariff General Terms and Conditions Section 6.3.3 (Farms) and subject to the SPECIAL CONDITIONS below.

BIMONTHLY RATE: All kW.h @ 11.749¢ per kW.h

plus:

CUSTOMER CHARGE: $37.39 per two Month period

OVERDUE ACCOUNTS: A late payment charge of 1 1/2 % will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

NOTE: For the purposes of Monthly billing the Customer Charge will be prorated on a Monthly basis.

SPECIAL CONDITIONS:

A. Farm Customers who elect to take service under this Rate Schedule must provide to FortisBC a copy of the most recent year's BC Assessment notice, or other acceptable documentation to FortisBC, identifying the subject property as having a farm classification.
B. Schedule 3 A – Exempt Residential Service for farm Customers will remain in effect until such time as a decision is rendered on the next FortisBC rate design application.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 20 - SMALL COMMERCIAL SERVICE

APPLICABLE:	To Commercial Customers whose electrical Demand is generally not more than 40 kW and can be supplied through one meter. Where there is more than one service to the same location and they are of the same voltage and phase classification and they were connected prior to January 5, 1977, the electrical energy and Demands registered for such services will be combined and billed at this rate.
BI-MONTHLY RATE:	All kW.h @ 10.000¢ per kW.h plus:
CUSTOMER CHARGE:	$46.00 per two Month period
DELIVERY AND METERING VOLTAGE DISCOUNTS:	The above rate applies to power service when taken at FortisBC's standard secondary voltage. A discount of 1 1/2% will be applied to the above rate if the electric service is metered at a primary distribution voltage.
OVERDUE ACCOUNTS:	A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.
NOTE:	For the purposes of Monthly billing the Customer Charge will be prorated on a Monthly basis.
PERMANENT RATE ESTABLISHMENT:	Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 21 - COMMERCIAL SERVICE

APPLICABLE: To Commercial Customers whose electrical Demand is generally greater than 40 kW but less than 500 kW and can be supplied through one meter. Where there is more than one service to the same location and they are of the same voltage and phase classification and they were connected prior to January 5, 1977, the electrical energy and Demands registered for such services will be combined and billed at this rate.

MONTHLY RATE: A Demand Charge of:

$11.35 per kW of "Billing Demand" above 40 kW

plus:

An Energy Charge of:

All kW.h 6.875¢ per kW.h

plus:

CUSTOMER CHARGE: $54.00 per Month

"Billing Demand"

The greatest of:

i. twenty-five per cent (25%) of the Contract Demand, or

ii. the maximum Demand in kW for the current billing Month, or

iii. seventy-five per cent (75%) of the maximum Demand in kW registered during the previous eleven Month period.

DELIVERY AND METERING VOLTAGE DISCOUNTS: The above rate applies to power service when taken at FortisBC's standard secondary voltage.

(a) A discount of 1 1/2% will be applied to the above rate if the electric service is metered at a primary distribution voltage.

RATE SCHEDULE 21 - COMMERCIAL SERVICE (Cont'd)

(b) A discount of 28.0¢ per kW of Billing Demand will be applied to the above rate if the Customer supplies the transformation from the primary to the secondary voltage.

(c) If a Customer is entitled to both of the above discounts, the discount applicable to the metering at a primary voltage is to be applied first.

POWER FACTOR: If at FortisBC's option, the Demand is measured in kVA instead of kW then;

40 kW will become 45 kVA
28.0¢ per kW will become 25.0¢ per kVA
$11.35 per kW will become $10.22 per kVA
where used in this schedule.

BILLING CODES: The following letter designations may appear on Customer's bills:

"A" – Demand measured in kW, FortisBC owned transformation from primary to secondary distribution voltage, metering at secondary distribution voltage
"B" – Demand measured in kVA, FortisBC owned transformation from primary to secondary distribution voltage, metering at secondary distribution voltage
"C" – Demand measured in kW, Customer owned transformation from primary to secondary distribution voltage, metering at primary distribution voltage
"D" – Demand measured in kVA, Customer owned transformation from primary to secondary distribution voltage, metering at primary distribution voltage

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 22 A - COMMERCIAL SERVICE – SECONDARY – TIME OF USE

APPLICABLE: To Commercial Customers whose electrical Demand is less than 500 kW and is supplied at a secondary distribution voltage through one meter. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	20.675
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	10.109
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	7.520

plus:

CUSTOMER CHARGE: $23.00 per Month

BILLING: FortisBC may, at its option, bill this rate bimonthly in which case the Customer Charge will be doubled.

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 23 A - COMMERCIAL SERVICE - PRIMARY - TIME OF USE

APPLICABLE: To Commercial Customers whose electrical Demand is less than 500 kW and is supplied at a primary distribution voltage through one meter. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	19.795
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	9.229
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	6.640

plus:

CUSTOMER CHARGE: $54.00 per Month

OVERDUE ACCOUNTS A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 30 - LARGE COMMERCIAL SERVICE - PRIMARY

APPLICABLE: To power service to Customers for a contract Demand of 500 kVA or more, subject to written agreement.

MONTHLY RATE: A Demand Charge of:

$9.19 per kVA of Billing Demand

plus:

An Energy Charge of:

All kW.h @ 5.571¢ per kW.h

plus:

CUSTOMER CHARGE: $945.04 per Month

"Billing Demand"

The greatest of:

i. twenty-five percent (25%) of the Contract Demand, or

ii. the maximum Demand in kVA for the current billing Month, or

iii. seventy-five percent (75%) of the maximum Demand in kVA registered during the previous eleven Month period.

RATE SCHEDULE 30 - LARGE COMMERCIAL SERVICE - PRIMARY (Cont'd)

DELIVERY AND
METERING VOLTAGE
DISCOUNTS: The above rate applies to power service when taken at FortisBC's standard primary distribution voltage available in the area.

(a) A discount of 1 1/2% will be applied to the above rate if the electric service is metered at a transmission line voltage.

(b) A discount of $5.26 per kVA of billing Demand will be applied to the above rate if the Customer supplies the transformation from the transmission line voltage to the primary distribution voltage.

(c) If a Customer is entitled to both of the above discounts, the discount applicable to the metering at a transmission line voltage is to be applied first.

OVERDUE
ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE
ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 31 - LARGE COMMERCIAL SERVICE - TRANSMISSION

AVAILABLE: In all areas served by FortisBC for supply at 60 hertz, three phase with a nominal potential of 60,000 volts or higher as available.

APPLICABLE: Applicable to industrial Customers with loads of 5,000 kVA or more, subject to written agreement.

MONTHLY RATE: A Wires Charge of:

$4.93 per kVA of Billing Demand; plus:

A Power Supply Charge of:

$3.45 per kVA of maximum Demand in current billing Month; plus:

An Energy Charge of:

All kW.h @ 5.367¢ per kW.h

CUSTOMER CHARGE: $3,195.00 per Month

"Billing Demand"

The greatest of:

i. eighty percent (80%) of the Contract Demand, or
ii. The maximum Demand in kVA for the current billing Month; or
iii. eighty percent (80%) of the maximum Demand in kVA recorded during the previous eleven Month period.

Plus, for Customers with a Stand-by Billing Demand under Rate Schedule 37 (except when Rate Schedule 37, Special Provision 7 applies);

Stand-by Billing Demand.

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 32 - LARGE COMMERCIAL SERVICE - PRIMARY - TIME OF USE

APPLICABLE: To power service to Customers for a contract Demand of 500 kVA or more, taking service at a standard primary distribution voltage, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service

RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	19.285
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	8.719
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	6.130

plus:

CUSTOMER CHARGE: $3,195.00 per Month

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 33 - LARGE COMMERCIAL SERVICE - TRANSMISSION - TIME OF USE

APPLICABLE: In all areas served by FortisBC for supply at 60 hertz, three phase with a nominal potential of 60,000 volts or higher as available. Applicable to industrial Customers with loads of 5,000 kVA or more, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	18.395
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	7.829
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	5.240

plus:

CUSTOMER CHARGE: $3,195.00 per Month

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 37 - LARGE COMMERCIAL SERVICE- STAND-BY SERVICE

AVAILABILITY: Stand-by Service is a Back-Up and Maintenance Service intended to provide the Customer with a firm supply of electric power and energy when the Customer's generating facilities are not in operation or are operating at less than full rated capability.

Stand-by Service is available only to those Customers that normally supply all or some portion of load from self-generation and is strictly for the continued operation of Customer facilities at times when the Customer-owned generation is unavailable.

Stand-by Service cannot be used by the Customer in the fulfillment of any power sales obligation.

Stand-by Service in only available to a Customer contracted to receive service under Rate Schedule 31 (Rate Schedule 31).

Rate Schedule 31 Contract Demand is the Customer’s Contract Demand expressed in kilovolt Amperes (kVA) and specified in the General Service Agreement (GSA) between FortisBC and the Customer. If the Customer and FortisBC cannot come to an agreement, the Rate Schedule 31 Contract Demand will be set by the British Columbia Utilities Commission.

Service taken up to a Customer’s Rate Schedule 31 Contract Demand is not considered to occur within a Stand-by Period.

Net Metering Customers are not eligible for Stand by Service.

DEFINITIONS:

In this Schedule,

1. “Customer” has the meaning provided in FortisBC’s Electric Tariff B.C.U.C. No. 2, Section 1 (Definitions).

2. “BCUC” means the British Columbia Utilities Commission.

3. “Maintenance Service” is provided during a FortisBC-approved scheduled outage for maintenance or downtime of the on-site generation.

RATE SCHEDULE 37 – LARGE COMMERCIAL SERVICE - STAND-BY SERVICE (Cont'd)

DEFINITIONS: (Cont'd)

4. "Back-Up Service" is an on-demand service required during unscheduled outages of the self-generation, ensuring that utility capacity is available for a Customer to call on to meet the Customer's load.

5. "Stand-by Period" is the total time during which the Customer is taking service under this Rate Schedule. Service taken up to a Customer's Rate Schedule 31 Contract Demand is not considered to occur within a Stand-by Period.

6. "Stand-by Penalty Period" occurs under the conditions identified in Special Provision 7.

7. "Stand-by Demand Limit (SBDL)", expressed in kVA, is required to be established under this Schedule for billing purposes. The SBDL for a Customer using this Schedule will set the maximum demand of service that can be supplied to the Customer under this Schedule. SBDL is to be agreed to between the Customer and FortisBC and is specified in the GSA between FortisBC and the Customer. If the Customer and FortisBC cannot come to an agreement, the SBDL will be set by the BCUC.

8. "Maximum Level of Stand-by Service", in any Hour, or metered portion thereof, capacity in kVA will be available to a maximum of the difference between the SBDL and the Customer's generation in that Hour in kVA.

SERVICES:

Part A: Maintenance Service

Maintenance Service is supplied during schedule outages of the Customer's generation for the purpose of maintenance of the generation facility. The Customer must schedule maintenance power with FortisBC not less than 30 Days prior to its use. Maintenance power service will be limited to not more than six occurrences and not more than sixty (60) total Days during a calendar Year.

Maintenance Service is terminated upon notification from the Customer that the event is over.

RATE SCHEDULE 37 – LARGE COMMERCIAL SERVICE - STAND-BY SERVICE (Cont'd)

SERVICES: (Cont'd)

Part B: Back-Up Service

Back-Up Service is supplied to replace energy generated by a Customer's own equipment when that equipment is not in service, except during periods of maintenance. Notification for the use of Back-Up Service must be provided as per Special Provision 4 and is limited to 876 Hours per calendar Year.

The provision of Back-Up Service will be considered to be automatically terminated if the Customer has not consumed FortisBC's electricity for 8 continuous Hours, after which time the Customer will be required to provide separate notice for a new instance of Back-Up Service.

CHARGES:

Monthly Rate: A Notification Fee of $200.00 per use; plus

Rate Schedule 37 Energy Charge:

An Hourly Stand-By Energy charge determined by:

(i) The Hourly Powerdex Mid-Columbia (Mid-C) per kWh price for the Hour in which the Stand-by Energy is taken by the Customer. In Hours in which the Mid-C price is negative, a value of $0.00 will be used; and

(ii) System losses as per Rate Schedule 109; and

(iii) Hourly transmission charges from the Mid-C hub to the border of $0.0040 per kWh; and

(iv) Administrative premium of 10 percent.

The Hourly charge is calculated as:

Rate Schedule 37 Energy Charges = [(Stand-by Energy x (1+ loss rate %)) x (Mid-C + 0.0040)] x 1.10

Where "Stand-by Energy" refers to the energy delivered during the Stand-by Period.

RATE SCHEDULE 37 – LARGE COMMERCIAL SERVICE - STAND-BY SERVICE (Cont'd)

CHARGES: (Cont'd)

Scenarios:

a. In any Hour all energy delivered up to or below the Rate Schedule 31 Contract Demand is not Stand-by Energy and is billed under Rate Schedule 31.

b. In any Hour, or metered portion thereof, if a Customer's demand exceeds the Rate Schedule 31 Contract Demand, but the demand in excess of the Rate Schedule 31 Contract Demand is less than the Maximum Level of Stand-by Service then:

   Stand-by Energy = total consumption – Rate Schedule 31 Contract Demand consumption

c. In any Hour, or metered portion thereof, if a Customer's demand exceeds the Rate Schedule 31 Contract Demand plus the Maximum Level of Stand-by Service allowed, service will be charge in accordance with Special Provision 7.

In any billing period, regardless of the above Scenario under which consumption charges are determined, total consumption will be equal to the total metered consumption recorded at the Customer's premise.

SPECIAL PROVISIONS:

1. Stand-by Billing Demand (SBBD) – Billing under this Rate Schedule requires the establishment of a SBBD, expressed in kVA. SBBD for a Customer using this Rate Schedule will be set at an amount between zero and 100 percent of the Customer's SBDL and is to be used in the determination of the Wires Charge in Rate Schedule 31. The SBBD is to be agreed to between the Customer and FortisBC and is specified in the GSA between FortisBC and the Customer. If the Customer and FortisBC cannot come to an agreement, the SBBD will be set by the BCUC.

2. Billing Demand in the underlying rate – The maximum demand recorded during a Stand-by Period will not be used in the calculation of Billing Demand in Rate Schedule 31.

3. Power Supply Demand Charge – The peak demand measured during a Stand-by Period will not be used in the calculation of demand charges in Rate Schedule 31.

RATE SCHEDULE 37 – LARGE COMMERCIAL SERVICE - STAND-BY SERVICE (Cont'd)

SPECIAL PROVISIONS: (Cont'd)

4. Back-Up Notification – The Customer must information FortisBC within 30 minutes of taking energy under the Back-Up provisions of this Schedule and inform FortisBC of the anticipated time that the generator will return to normal operations. If the Customer's generator is not available at the anticipated time, further notice including an updated anticipated time that the generator will return to normal operations must be provided.

5. Metering – The Customer must have FortisBC approved interval metering and meter communications in place prior to initiation of service under this Rate Schedule. FortisBC requires metering that measures the net quantity and direction of flow at the point of interconnection between the Customer and FortisBC and total generator output.

6. Required Equipment – The Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which FortisBC's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and the necessary wiring on both sides of the transformers. All transformers, equipment and wiring will be of types and characteristics approved by FortisBC and their installation, operation and maintenance will be subject to inspection and approval by FortisBC.

7. Stand-by Penalty Period - In any Hour, or metered portion thereof, if a Customer's demand exceeds the Rate Schedule 31 Contract Demand plus the Maximum Level of Stand-by Service allowed or a Customer's demand exceeds the Rate Schedule 31 Contract Demand and the Customer is not eligible for either Maintenance or Back-Up Service due to the restrictions under this Rate Schedule service above the Customer's Rate Schedule 31 Contract Demand will be considered a Stand-by Period subject to the following penalty:

   In a Stand-By Penalty Period Hour:

   a. Rate Schedule 37 Energy Charge (i) will be replaced with:

      The Hourly per kWh price for the Hour in which the Stand-by Energy is taken by the Customer is the greater of:

      i. $1,000

      ii. $50/MWh calculated as:

         [(Stand-by Energy x (1 + loss rate %)) x (0.05 + 0.0040)] x 1.10

      iii. 150 percent of the Energy Charge that would have resulted under the calculation of Rate Schedule 37 Energy Charge (i) in this Rate Schedule calculated as:

         [(Stand-by Energy x (1 + loss rate %)) x ((Mid-C x 1.5) + 0.0040)] x 1.10

RATE SCHEDULE 37 – LARGE COMMERCIAL SERVICE - STAND-BY SERVICE (Cont'd)

SPECIAL PROVISIONS: (Cont'd)

b. Special Provision 2 will not apply. The maximum demand recorded in the Hour during a Stand-by Penalty Period will be used in the current billing period's calculation of Billing Demand in Rate Schedule 31 but will not set a ratchet that will be used in the calculation of Billing Demand in Rate Schedule 31 in future billing periods.

   When Back-Up Service is taken in excess of the calendar Year Hourly limit or when Special Provision 4 has been violated FortisBC will waive the penalty under the following circumstances:

   a. An extreme or unusual circumstance as identified in the force majeure provision in FortisBC's approved tariff, Section 12 limits the self-generation of the Customer; or

   b. A temporary reduction in Customer generation, as a response to a system issue on FortisBC's system, which takes the Customer's generation off-line.

   Where service is taken during a Stand-by Period, but is taken under the circumstances described in items a. and b. above, and is not taken as described in Scenario c. of the Energy Charges section of this Schedule, the duration of the Stand-by Period involved will not be counted toward the limitation on Stand-by Service of 876 Hours per calendar Year.

RATE SCHEDULE 40 - WHOLESALE SERVICE - PRIMARY

AVAILABLE: In Grand Forks, Kelowna, Penticton, Princeton, Summerland, Lardeau and Yahk.

APPLICABLE: To service for resale, subject to written agreement.

MONTHLY RATE: A Wires Charge of:

$8.98 per kVA of Billing Demand

plus:

A Power Supply Charge of:

$4.82 per kVA of maximum Demand in current billing Month

plus:

An Energy Charge of:

All kW.h @ 5.441¢ per kW.h

CUSTOMER CHARGE: $2,645.03 per Point of Delivery per Month

"Billing Demand"

The greatest of:

i. eighty percent (80%) of the Contract Demand, or
ii. the maximum Demand in kVA for the current billing Month, or
iii. eighty percent (80%) of the maximum Demand in kVA registered during the previous eleven Month period.

RATE SCHEDULE 40 - WHOLESALE SERVICE - PRIMARY (Cont'd)

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

DELIVERY VOLTAGE DISCOUNT: The above rate applies to power service when taken at FortisBC's standard primary voltage.

A discount of 0.770¢ per kW.h will be applied to the Energy Charge and a discount of $2.64 per kVA will be applied to the Power Supply Charge if the Customer supplies the transformation from the transmission line voltage to the primary distribution voltage.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 41 - WHOLESALE SERVICE - TRANSMISSION

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

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

MONTHLY RATE: A Wires Charge of:

$6.34 per kVA of Billing Demand

plus:

A Power Supply Charge of:

$4.77 per kVA of maximum Demand in current billing Month

plus:

An Energy Charge of:

All kW.h @ 4.501¢ per kW.h

CUSTOMER CHARGE: $5,974.48 per Month

"Billing Demand"

The greatest of:

i. eighty percent (80%) of the Contract Demand, or
ii. the maximum Demand in kVA for the current billing Month, or
iii. eighty percent (80%) of the maximum Demand in kVA registered during the previous eleven Month period.

RATE SCHEDULE 41 - WHOLESALE SERVICE – TRANSMISSION (Cont'd)

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

RATE FOR EMERGENCY PURPOSES: The additional Demand resulting from emergency or shutdown service (Emergency Demand) will be excluded in determining the application of Item (c) in the calculation of the Billing Demand, provided the City of Nelson requests that the Demand meter be read by FortisBC immediately before and after the emergency or as soon as practical at the commencement of the emergency period. The amount of Emergency Demand will be determined from the meter readings and the best information available. The City of Nelson will compensate FortisBC for any higher Demand charges resulting from the Emergency Demand.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 42 - WHOLESALE SERVICE - PRIMARY -TIME OF USE

APPLICABLE: To power Service to Grand Forks, Kelowna, Penticton, Summerland, Lardeau, and Yahk, at a Primary Voltage for resale, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by FortisBC, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive Months after commencement of Service.

RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	19.995
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	9.429
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	6.840

plus:

CUSTOMER CHARGE: $2,645.03 per Month per Point of Delivery

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 43 - WHOLESALE SERVICE - TRANSMISSION - TIME OF USE

APPLICABLE: To supplementary power service to the City of Nelson, subject to written agreement. At suitable City of Nelson interconnections with FortisBC's 63kV system. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	19.185
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	8.619
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	6.030

plus:

CUSTOMER CHARGE: $895.79 per Month

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 50 - LIGHTING - ALL AREAS

APPLICABLE: To lighting applications where the Customer will contract for service for a term of one Year. FortisBC will supply service for lighting from dusk to dawn daily.

All lighting equipment installed on and after the effective date of this Schedule will be FortisBC approved and conform to all relevant FortisBC design and installation standards and requirements, and be suitable to accept electrical service at FortisBC's available secondary voltage. Other requirements may be supplied under special contract.

This Schedule is not available for equipment other than FortisBC approved lighting fixtures.

TYPES OF SERVICE:

1. Customer-Owned and Customer-Maintained

Type I - For a Customer-owned street lighting fixture or lighting system where the Customer owns and maintains at its own expense the light standards if any, lighting fixtures and all auxiliary equipment.

Electricity at 120/240 volts single phase is supplied by FortisBC at a single point of delivery for each separate Customer system. Multiple light systems will be provided service at a single point of delivery wherever practical. The Customer will supply transformers for other than 120/240 volt single phase supply.

Type I will apply only if the Customer system can be operated and maintained, beyond the point of supply of electricity, independently of FortisBC's system. The installed cost of devices necessary for independent operation will be paid by

the Customer. Where Customer owned lighting fixtures are on FortisBC owned poles maintenance work will only be performed by parties qualified to do the work, and authorised by FortisBC. FortisBC reserves the right to refuse Type I service for any reason.

2. Customer-Owned and FortisBC-Maintained

Type II - Customer-owned street lighting fixtures installed on existing FortisBC poles at the Customer's expense with all maintenance to be performed by FortisBC at costs described below.

RATE SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

TYPES OF SERVICE: (Cont'd)

3. FortisBC-Owned, FortisBC-Installed and Maintained

Type III - For FortisBC-owned street lighting fixtures on existing FortisBC-owned poles where FortisBC performs all maintenance. Facilities provided by FortisBC, including fixtures, lamp, control relay, support bracket, and conductor and energy for operation thereof are owned by FortisBC.

TERMS AND CONDITIONS:

Installation

Type II lighting fixtures of design and specifications approved by FortisBC for installation on FortisBC-owned poles will be installed by FortisBC at the Customer's expense. There will be no charge to the Customer for the use of existing FortisBC-owned poles as standards for mounting of fixtures other than as provided for in this section.

FortisBC will provide to the Customer on request, lighting fixtures and standards, where required, of FortisBC approved design and specifications at its cost plus overheads and handling costs as described in the Cost Recovery section below. For Type III fixtures FortisBC will provide one span of duplex of not more than 30 metres.

Extension of Service

Extensions of service will be provided under the terms of FortisBC's Extension Policy.

Relocation

At the Customer's request, the location of a light may be changed provided the Customer pays for the cost of removal and reinstallation, including cost of extension of service if applicable, with costs recovered as described below.

Other Equipment

Equipment other than lighting fixtures is not permitted on FortisBC-owned poles except with FortisBC's written consent.

Dimmable Lighting

Dimmable service is only available for Type I and Type II lighting service where the Customer has five or more fixtures. For Type II service the Customer will provide to FortisBC an adequate supply of replacement parts at no cost to FortisBC.

RATE SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

TERMS AND CONDITIONS:

Dimmable Lighting (Cont'd)

For each dimmable fixture, the Customer will provide FortisBC with a schedule showing the rated wattage of the lamp and auxiliary devices together with a schedule showing the wattage consumed each Hour and the resultant annual kW.h consumption. FortisBC will bill one-twelfth of the annual consumption each Month. The Customer will provide timely notification of any changes of operation, number and/or wattage of fixtures on June 1 of each year. The Customer will provide access to the dimmable fixtures upon reasonable notice by FortisBC to the Customer.

Maintenance of Type III Lights

Maintenance of Type III lighting fixtures will be performed by FortisBC, the cost of which is provided for in the "Monthly Rate" of this Schedule. Such work will be undertaken by FortisBC during regular working Hours and FortisBC will be allowed ten working Days subsequent to notification by the Customer for performance of such maintenance. Cleaning of the glassware will be carried out only when the lamp is replaced.

The Customer will be responsible for any wilful damage to FortisBC's equipment.

Maintenance of Type II Lights

The Customer will pay maintenance and capital costs, including the cost of installation, maintenance of underground supply, and relocation, on an as spent basis. Customers will inform FortisBC in writing of the location of any lighting fixture requiring maintenance and the time in which the maintenance must be performed. FortisBC will bill the Customer for all costs incurred including the following overheads:

Cost Recovery

Labour Loading

On labour costs excluding overtime	74% of labour rate

Material Loading

Inventory – Material Handling	10% of cost

Loading rates may be adjusted from time to time as required to ensure appropriate recovery of costs.

RATE SCHEDULE 50 - LIGHTING - ALL AREAS (Cont'd)

MONTHLY RATE FOR EACH
TYPE OF SERVICE:

Type of Light	Watts	Monthly Use (kWh)	Nominal Lumens	Rate ($ per Month) Customer-Owned Type I	Customer-Owned Type II	FortisBC-Owned Type III
Fluorescent	*383	140	21,800	27.43		
Mercury Vapour	*125	55	5,000	11.00	11.00	24.30
	*175	78	7,000	15.52	15.52	28.91
	*250	107	10,000	21.31	21.31	34.69
	*400	166	21,000	33.05	33.05	46.43
Sodium Vapour	70	33	6,000	6.67	6.67	19.96
	*100	47	9,000	9.35	9.35	22.72
	*150	70	14,000	13.90	13.90	27.30
	200	91	20,000	18.13	18.13	31.50
	250	111	23,000	22.14	22.14	35.45
	*400	173	45,000	34.46	34.46	47.86

For Type I and Type II, Light Emitting Diode (LED) lighting service will be supplied at a Monthly rate of 0.1989 per kWh as determined according to the General Terms and Conditions.

* No longer available at new locations or as replacement fixtures where existing fixtures are being replaced except at the sole discretion of FortisBC.

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% (compounded monthly 19.56% per annum) will be assessed each month on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 60 - IRRIGATION AND DRAINAGE

AVAILABLE: For an irrigation and drainage season commencing April 1st each year and terminating October 31st each year. Meter readings will be taken within 10 Business Days of the commencement and termination of the irrigation and drainage season. During the non-irrigation season Customers will be automatically transferred to the applicable Commercial rate and billings prorated for a partial first or final service Month when read dates are outside of the 10 Day band.

APPLICABLE: To motors at one point of delivery, which are to be used primarily for irrigation and drainage purposes. This schedule applies to electric service when taken at FortisBC's standard secondary voltage. Incidental lighting essential to the pumping operation will be allowed on this schedule provided that the Customer supplies and installs his own transformers and other necessary equipment as required. Service to motors of 5 HP or less will be single phase, unless FortisBC specifically agrees to supply three phase.

BILLING: Bills will be rendered Monthly or bimonthly but may be estimated in periods of low consumption or when access is restricted.

MONTHLY RATE: All kW.h @ 7.240¢ per kW.h

CUSTOMER CHARGE: $22.09 per Month

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 61 - IRRIGATION AND DRAINAGE - TIME OF USE

APPLICABLE: For Customers normally supplied under Rate Schedule 60. Service to motors of 5 HP or less will be single phase, unless FortisBC specifically agrees to supply three phase. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

RATES BY PRICING PERIOD:

	Summer July-August	**Shoulder** March-June September-November	**Winter** December-February	¢/kW.h
On-Peak	7 am to 12 pm 4 pm to 9 pm Business Days		12 pm to 9 pm Business Days	17.869
Mid-Peak	12 pm to 4 pm Business Days	7 am to 9 pm Business Days	7 am to 12 pm Business Days	7.303
Off-Peak	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	9 pm to 7 am Business Days All Hours on Saturday, Sunday and statutory holidays	4.714

plus:

CUSTOMER CHARGE: $22.09 per Month

OVERDUE ACCOUNTS: A late payment charge of 1 1/2% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

SCHEDULE 85 - GREEN POWER RIDER

APPLICABLE: To any current rate Schedules and on the same terms applicable to rate Schedule under which Service is taken, for the purchase of Electricity from environmentally desirable technologies.

RATE: OPTION A - In addition to all charges on the applicable rate Schedule, an additional charge, of all discounts, of 1.500¢ per kW.h is levied against all kW.h sold.

OPTION B - In addition to all charges on applicable rate Schedule, the Customer may select a dollar amount of their choosing to be added to their periodic billing, but in no case will the amount be less than $2.50 per Month.

SCHEDULE 90 - DEMAND-SIDE MANAGEMENT SERVICES

APPLICABLE: To all Customers in all areas served by FortisBC and its municipal wholesale Customers.

OBJECTIVE: The purpose of FortisBC's Demand-Side Management (DSM) Services is to promote the efficient use of Electricity, in terms of consumption (Conservation) and/or timing (Demand Response).

PROGRAMS: DSM programs, compliant with applicable regulations, address electrical end-uses, through approved Measure(s), which may consist of an energy-efficient product, device, piece of equipment, system, building or process design and/or operational practice which exceeds applicable codes and/or current practice.

FortisBC will maintain an updated DSM program listing on its website, available in print format, detailing current program offerings and rules.

FINANCIAL DETAILS: DSM programs will consist of monetary incentives provided by FortisBC in the form of custom option or product option offerings to promote the purchase and installation of approved Measures. Incentives are targeted to Customers but may also be provided to trade allies who provide or install the Measures.

Monetary incentives are based on the annual kWh savings, or the on-peak kW reduction, attained through the Measure as determined on a prescriptive or custom calculation basis.

Monetary incentives are capped to the lesser of:

i. FortisBC's long-term avoided power purchase costs,
ii. 50% of installed Measure cost for existing construction,
iii. 100% of incremental cost for new construction, or
iv. The amount sufficient for the Customer to achieve a two-Year payback.

Monetary incentives may alternately consist of low-cost financing O.A.C. for residential Customers only.

DSM Services may also consist of non-monetary offerings in the form of: public information, educational programs, or training; audits of Customer Premises or processes or Measures and reports thereof; product samples; pilot projects to test new Measures; and market transformation activities undertaken in conjunction with other utilities and/or governments.

SCHEDULE 90 – DEMAND-SIDE MANAGEMENT SERVICES (Cont'd)

TERMS AND CONDITIONS

The following terms and conditions are an integral part of the Demand-Side Management Services listed under Schedule 90:

FINANCIAL INCENTIVES

1. In order to be eligible for financial incentives, a Customer must receive FortisBC's approval prior to initiation of work on the approved Measure.
2. Only those audit or upgrade costs which are pertinent to DSM considerations will be eligible for financial incentives. An estimate of costs related to such issues as obsolescence, depreciation, maintenance, plant betterment and environmental concerns will be made to isolate that portion of the cost strictly related to energy.
3. Where incentives are in excess of $10,000, payment of one half of the rebate will be deferred for up to one Year. Upon confirmation of project savings, the remaining portion of the rebate will be paid pro rata to the energy savings. No interest will be paid on the withheld portion. Irrespective of actual savings, the final rebate will not exceed the original estimated rebate.
4. For those Customers in receipt of an incentive in excess of $20,000, the unamortized balance of financial incentives paid to or on behalf of the Customer, under Rate Schedule 90 will be remitted to FortisBC within 30 Days of billing, if:

   (a) the incented equipment or facilities are disabled or removed;

   (b) the Customer's electrical load is reduced by more than 50% for a continuous period of twelve Months or longer; or

   (c) over 50% of the Electricity previously provided by FortisBC is replaced by another source including self-generation or another supplier.

   In regards to (c) above, the repayment will be prorated based on the amount of energy replaced compared to the amount of energy supplied by FortisBC in the Year immediately preceding the Electricity replacement.

5. Any consulting or study subsidy offered under the Demand-Side Management tariff is contingent upon available budget and resources. When FortisBC pays more than $1,500 for these Services on behalf of a Customer, any incentive amount that is eventually payable to that Customer will be reduced by the amount of the consulting or study contribution.

SCHEDULE 91 – ON-BILL FINANCING PILOT PROGRAM - CLOSED

APPLICABLE: To all eligible Customers located in the City of Kelowna and the Regional District of Okanagan-Similkameen, excluding the City of Penticton and the District of Summerland for the energy efficiency improvement to an eligible Premises, or a part of an eligible Premises.

ELIGIBLE CUSTOMERS: In order to be eligible for the Loan, the Customer must:

(a) receive or will receive Service from FortisBC;

(b) participate in the Equal Payment Plan as specified in Section 8.6 (Equal Payment Plan);

(c) have paid on or before the due date, all or all but one of FortisBC's bills issued, if any, during the twelve Month period preceding the date of the application for the Loan;

(d) as of the date for applying for the Loan, have a credit rating of at least 650 on the Equifax Beacon rating system (i.e. a credit rating of 650 or higher); and

(e) be the lawful owner of an eligible Premises evidenced by a copy of the Land Title Certificate.

If the copy of the Land Title Certificate is not available, the Customer must consent to FortisBC to conduct a search of the Land Title Office to verify ownership.

ELIGIBLE PREMISES: The Loan is for improving energy efficiency to a Premises, or part of a Premises that is a residential building of three stories or less that occupies no more than 600 square meters of ground service, is habitable all year and is:

(a) a detached home;

(b) a building that is part of a complex of side-by-side attached buildings; or

(c) a mobile home on a permanent foundation.

SCHEDULE 91 – ON-BILL FINANCING PILOT PROGRAM (cont'd)

ELIGIBLE ENERGY EFFICIENCY IMPROVEMENTS: The energy efficiency improvements to a Premises or a part of a Premises eligible for the Loan must

(a) fall into one of the following categories:

(i) air sealing;

(ii) mechanical ventilation;

(iii) attic insulation;

(iv) exterior wall insulation;

(v) basement, crawlspace and header insulation;

(vi) primary method of heating occupied space;

(vii) domestic hot water heating; or

(viii) window and door replacement; and

(b) be a qualified retrofit measure under the Ministry of Energy, Mines and Natural Gas LiveSmart BC program.

ENERGY REPORT: To be eligible for the Loan, the improvements specified herein must be recommended in an energy report respecting the eligible Premises or the part of the Premises. The energy report must be completed and signed by a qualified energy advisor no more than eighteen calendar months before the date of the Financing Agreement. A qualified energy advisor is certified as such by Natural Resources Canada and employed by or under contract with a service organization licenced by Natural Resources Canada to perform EnerGuide Rating System evaluations.

SCHEDULE 91 – ON-BILL FINANCING PILOT PROGRAM (cont'd)

APPLICATION FOR LOAN: A Customer may apply for the Loan to FortisBC in the same way as applying for Services with FortisBC under Section 2 (Application for Service) of the General Terms and Conditions. The number of Customers eligible to receive the Loan will be limited and the determination of eligibility will be made by FortisBC in its sole discretion, acting reasonably. FortisBC reserves the right to deny a Loan to a Customer should FortisBC determine that the terms and conditions for the On-Bill Financing Pilot Program and/or the provisions of the *Improvement Financing Regulations* are not met.

COMPLETION OF IMPROVEMENTS: The energy efficiency improvements must be completed

(a) by the owner of the Premises or a part of the Premises or by a "qualified person" as defined in the *Improvement Financing Regulation*; and

(b) within six calendar months of the date FortisBC approves the application for the Loan.

Failure to complete improvements as specified herein may result in withdrawal of the approval for the Loan or termination of the Financing Agreement.

RIGHT TO INSPECT: FortisBC has the right to inspect the Premises or the part of the Premises subject to the Financing Agreement at a reasonable time up to 36 calendar months after the completion of the improvements.

SCHEDULE 91 – ON-BILL FINANCING PILOT PROGRAM (cont'd)

TERMINATION OF PROGRAM: FortisBC may terminate the On-Bill Financing Pilot Program at any time and without notice subject to the provisions of the *Clean Energy Ac*t [SBC 2010], c. 22 and any regulations promulgated thereunder. Notwithstanding the foregoing, all Financing Agreements and obligations thereunder duly entered into under the On-Bill Financing Pilot Program up to the date of termination will survive such termination.

BASIC TERMS OF THE FINANCING AGREEMENT

In addition to the terms listed above under Schedule 91 and the charges, if applicable, for Disconnection and Reconnection of Meter, Required Cheque Service, and Collection listed under Schedule 80, the following terms and conditions are an integral part of the On-Bill Financing Pilot Program:

1. The Customer must meet all the eligible requirements contained herein and sign the applicable Financing Agreement provided by FortisBC in order to receive the Loan.

2. The Financing Agreements under the On-Bill Financing Pilot Program have a term of ten Years.

3. The Loan will be paid in 120 equal Monthly installments. The equal Monthly installments will form a component of FortisBC's electric utility bill known as the On-Bill Financing Charge and will be subject to normal utility collection procedures, including service disconnect, as outlined in Section 8.2 (Payment of Accounts).

4. Available Loan amounts under the On-Bill Financing Pilot Program are limited to a minimum principal amount of $1,000 and a maximum principal amount of $10,000 per Premises.

5. The interest charged by FortisBC on the principal amount of the Loan does not exceed 4.5 annual percentages.

SCHEDULE 91 – ON-BILL FINANCING PILOT PROGRAM (cont'd)

BASIC TERMS OF THE FINANCING AGREEMENT (cont'd)

6. Subject to FortisBC's written consent, the Customer may transfer the Financing Agreement upon the sale of the Premises or the part of the Premises subject to the Financing Agreement to a new owner provided the new owner must:

   (a) meet all eligibility requirements established herein;
   (b) be approved by FortisBC; and
   (c) sign a Notice of Transfer provided in the Improvement Financing Regulation as a schedule.

   Should the new owner not meet the eligibility requirements or should the new owner not be approved by FortisBC, the balance of the Loan amount due under the Financing Agreement must be paid in full, including applicable interest amounts.

7. The Customer's obligations under the Financing Agreement are not discharged until

   (a) the full amount payable under the Financing Agreement is paid; or
   (b) the Financing Agreement is transferred as specified herein.

RATE SCHEDULE 95 - NET METERING

DEFINITION:

Customer-Generator - An electric Service Customer of FortisBC that also utilizes the output of a Net Metered System.

Net Consumption - Net Consumption occurs at any point in time where the Electricity required to serve the Customer-Generator's load exceeds that being generated by the Customer-Generator's Net Metered System.

Net Generation - Net Generation occurs at any point in time where Electricity supplied by FortisBC to the Customer-Generator is less than that being generated by the Customer-Generator's Net Metering System.

Net Excess Generation - Net Excess Generation results when over a billing period, Net Generation exceeds Net Consumption.

Net Metering - Net Metering is a metering and billing practice that allows for the flow of Electricity both to and from the Customer through a single, bi-directional meter. With Net Metering, consumers with small, privately-owned generators can efficiently offset part or all of their own electrical requirements by utilizing their own generation.

Net Metered System - A facility for the production of electric energy that:

(a) uses as its fuel, a source defined as a clean and renewable resource in the BC Energy Plan;

(b) has a design capacity of not more than 50 kW;

(c) is located on the Customer-Generator's Premises;

(d) operates in parallel with FortisBC's transmission or distribution facilities; and

(e) is intended to offset part or all of the Customer-Generator's requirements for Electricity.

APPLICABLE: To FortisBC Customers receiving Service under Rate Schedules 1, 2A, 20, 21, 22, 22 A, 23 A, 60, 61.

RATE SCHEDULE 95 - NET METERING (Cont'd)

ELIGIBILITY: To be eligible to participate in the Net Metering Program, Customers must generate a portion or all of their own retail Electricity requirements using a renewable energy source. The generation equipment must be located on the Customer's Premises, Service only the Customer's Premises and must be intended to offset a portion or all of the Customer's requirements for Electricity.

Clean or renewable resources include sources of energy that are constantly renewed by natural processes, such as water power, solar energy, wind energy, geothermal energy, wood residue energy, and energy from organic municipal waste, and will have a maximum installed generating capacity of no greater than 50 kW.

RATE: A Customer enrolled in the Net Metering Program will be billed as set forth in the Rate Schedule under which the Customer receives electric Service from FortisBC and as specified in the Net Metering Billing Calculation section in this schedule.

BILLING CALCULATION:

1. Net metering will be, for billing purposes, the net consumption at FortisBC's Service meter(s).
2. If the eligible Customer-Generator is a net consumer of energy in any billing period, the eligible Customer generator will be billed in accordance with the Customer-Generator's applicable Rate Schedule.
3. If in any billing period, the eligible Customer-Generator is a net generator of energy, the Net Excess Generation will be valued at the rates specified in the applicable Rate Schedule and credited to the Customers account.
4. For eligible Customers receiving Service under a Time-of-Use (TOU) Rate Schedule, consumption and generation during On-Peak Hours will be recorded and netted separately from consumption and generation during Off-Peak Hours such that any charges or credits applied to the account reflect the appropriate time-dependent value for the energy.
5. In the event that the operation of a renewable energy generating system results in a credit balance on the Customer-Generator's account at the end of a calendar Year, the credit will be purchased by FortisBC. If such amounts are not large, they will be carried forward and included in the billing calculation for the next period at the discretion of FortisBC.

RATE SCHEDULE 95 - NET METERING **(Cont'd)**

SPECIAL CONDITIONS:

1. Prior to the interconnection of a Net Metering System the Customer-Generator must submit a Net Metering Application for review and execute a written Net Metering Interconnection Agreement with FortisBC.
2. The Net Metered System and all wiring, equipment and devices forming part of it, will conform to FortisBC's, "GUIDELINES FOR OPERATING, METERING And PROTECTIVE RELAYING FOR NET METERING SYSTEMS UP TO 50 kW And VOLTAGE BELOW 750 VOLTS" and will be installed, maintained and operated in accordance with those Requirements.
3. Unless otherwise approved by FortisBC, the Customer-generator's Service will be metered with a single, bi-directional meter.
4. The Contract Period for Service under this schedule will be one (1) Year and thereafter will be renewed for successive one-Year periods. After the initial period, the Customer may terminate Service under this Rider by giving at least sixty (60) Days previous notice of such Termination in writing to FortisBC.
5. If the Customer-Generator voluntarily terminates the net-metering Service, the Service may not be renewed for a period of 12 Months from the date of Termination.
6. FortisBC maintains the right to inspect the facilities with reasonable prior notice and at a reasonable time of Day.
7. FortisBC maintains the right to disconnect, without liability, the Customer-Generator for issues relating to safety and reliability.
8. Inflows of Electricity from the FortisBC System to the Customer-Generator, and outflows of Electricity from the Customer-Generators Net Metering System to the FortisBC System, will normally be determined by means of a single meter capable of measuring flows of Electricity in both directions.
9. Alternatively, if FortisBC determines that flows of Electricity in both directions cannot be reliably determined by a single meter, or that dual metering will be more cost-effective, FortisBC may require that, at the Customers cost, separate meter bases be installed to measure inflows and outflows of Electricity.
10. Except as specifically set forth herein, Service supplied under this schedule is subject to the General Terms and Conditions set forth in FortisBC's Electric Tariff on file with the British Columbia Utilities Commission.

RATE SCHEDULE 95 - NET METERING **(Cont'd)**

SPECIAL CONDITIONS: (Cont'd)

1. A Net Metered System used by a Customer-Generator will meet all applicable safety and performance standards established as set forth in FortisBC's Rules and Regulations.
2. A Customer-Generator will, at its expense, provide lockable switching equipment capable of isolating the Net Metered System from FortisBC's system. Such equipment will be approved by FortisBC and will be accessible by FortisBC at all times.
3. The Customer-Generator is responsible for all costs associated with the Net Metered System and is also responsible for all costs related to any modifications to the Net Metered System that may be required by FortisBC including but not limited to safety and reliability.
4. The Customer will indemnify and hold FortisBC or its agents harmless for any damages resulting to FortisBC or its agents as a result of the Customer's use, ownership, or operation of the Customer's facilities other than damages resulting to FortisBC or its agents directly as a result of FortisBC or its agents own negligence or willful misconduct, including, but not limited to, any consequential damages suffered by FortisBC or its agents. The Customer is solely responsible for ensuring that the Customer's facilities operate and function properly in parallel with FortisBC's system and will release FortisBC or its agents from any liability resulting to the Customer from the parallel operation of the Customer's facilities with FortisBC's system other than damages resulting to the Customer from the parallel operation of the Customer's facilities with FortisBC's system directly as a result of FortisBC or its agents own negligence or willful misconduct.

RATE SCHEDULE 100 - NETWORK INTEGRATION TRANSMISSION SERVICE

AVAILABILITY: For Network Integration Transmission Service.

RATE: Monthly Network Transmission Revenue Requirement:

Customers will be charged the applicable Load Ratio Share of one twelfth ($1/12^{th}$) of the Network Transmission Revenue Requirement per Month. The Network Transmission Revenue Requirement is as set forth in Attachment H to Electric Tariff Supplement No. 7.

NOTE: The terms and conditions under which Network Integration Transmission Service is supplied are contained in Electric Tariff Supplement No. 7 and capitalized terms appearing in this Rate Schedule, unless otherwise noted, will have the meaning ascribed to them therein.

RATE SCHEDULE 101 - LONG-TERM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

AVAILABILITY: For transmission of Electricity on a firm basis from one or more Point(s) of Receipt (POR) to one or more Point(s) of Delivery (POD).

ANNUAL RATE FOR LONG-TERM FIRM SERVICE:

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 (BC Hydro) and the power is being delivered to a load with or beyond the BC 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.

RATES FOR SHORT-TERM FIRM SERVICE

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 the POD is a point of interconnection between the Transmission System and the transmission system of BC Hydro and the power is being delivered to a load within or beyond the BC 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.

MINIMUM PRICE: $0.002 per kW per Hour

MAXIMUM PRICE: The Transmission Customer will pay each Month for Reserved Capacity designated at the POD at rates not to exceed the applicable charges set forth below.

Delivery	Transmission	Distribution
	per kW of Reserved Capacity Demand	
Monthly	$4.20	$8.07
Weekly	$0.9692	$1.8623
Daily	$0.1381	$0.2653
Hourly	$0.0058	$0.0111

RATE SCHEDULE 101 - LONG-TERM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE (Cont'd)

SPECIAL CONDITION:

Discounts: Three principal requirements apply to discounts for Transmission Service as follows:

1. any offer of a discount made must be announced to all Transmission Customers on the FBC website in a timely manner;

2. any Customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must be provided to other Transmission Customers on the FBC website; and

3. once a discount is negotiated, details must be immediately posted on the FBC website. For any discount agreed upon for Service on a path, from POR to POD, an offer of the same discounted transmission Service rate for the same time period must be made for all unconstrained transmission paths that go to the same POD on the Transmission System.

NOTE: The terms and conditions under which Transmission Service is supplied are contained in Electric Tariff Supplement 7. Capitalized terms appearing in this Rate Schedule, unless otherwise noted, will have the meaning ascribed to them therein.

PENALTY CHARGE:

A penalty charge will be applied at the rate of 125 per cent of the applicable rate for all usage in excess of the Reserved Capacity.

RESERVED CAPACITY BILLING DEMAND:

The sum of the Reserved Capacity designated at each POD for the applicable period.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 103 - SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

PREAMBLE: This Service is required to schedule the movement of power through, out of, or within the Service territory.

The Transmission Customer must purchase this Service if taking supply under Rate Schedules 100, 101 and 102.

MAXIMUM MONTHLY RATE: $0.16690 per kW.h of Reserved Capacity per Month

MAXIMUM WEEKLY RATE: $0.03850 per kW.h of Reserved Capacity per week

MAXIMUM DAILY RATE: $0.00550 per kW.h of Reserved Capacity per day

MAXIMUM HOURLY RATE: $0.00023 per kW.h of Reserved Capacity per Hour

NOTE: A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 104 - REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICES

PREAMBLE: In order to maintain Transmission Voltages on transmission facilities within acceptable limits, generation facilities under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain Transmission Voltages within limits that are generally accepted in the region.

The Transmission Customer must purchase this Service if taking supply under Rate Schedules 100, 101, and 102.

RATE: $0.82500 per kW.h of Reserved Capacity per Hour

NOTE: A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 105 - REGULATION AND FREQUENCY RESPONSE SERVICE

PREAMBLE: Regulation and Frequency Response (RFR) Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The Transmission Customer must either purchase this Service from FortisBC or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below.

AVAILABILITY: In support of the transmission of Electricity under Rate Schedules 100 and 101.

RATE: $9.31 per mega-watt per Hour of generating capacity requested for RFR.

The required amount of RFR Service is a minimum of 2% of the Customer's load located in FortisBC's Service territory.

NOTE: A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 106 - ENERGY IMBALANCE SERVICE

PREAMBLE: Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a FortisBC's Service territory over a single Hour. FortisBC must offer this Service when the transmission Service is used to serve load within its Service area. The Transmission Customer must either purchase this Service from FortisBC or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. FortisBC will establish a deviation band of +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied Hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Parties should attempt to eliminate energy imbalances within the limits of the deviation band within thirty (30) Days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by FortisBC. If an energy imbalance is not corrected within thirty (30) Days or a reasonable period of time that is generally accepted in the region and consistently adhered to by FortisBC, the Transmission Customer will compensate FortisBC for such Service. Energy imbalances outside the deviation band will be subject to charges to be specified by FortisBC. The charges for Energy Imbalance Service are set forth below.

AVAILABILITY: In support of the transmission of Electricity under Rate Schedules 100 and 101.

ENERGY IMBALANCE: Energy imbalances are calculated Hourly based on deviations from scheduled generation and load. Positive imbalances occur when actual generation is greater than scheduled or when actual load is less than scheduled load and results in a delivery of Energy from the Customer to FortisBC. Negative imbalances occur when actual generation is less than schedule generation or when actual load is greater than scheduled load and results in a delivery of Energy from FortisBC to the Customer.

RATE SCHEDULE 106 - ENERGY IMBALANCE SERVICE (Cont'd)

A positive imbalance will be credited as the lower of:

(i) The Tranche 1 Energy Price set out in BC Hydro Rate Schedule 3808 as of January 1 in the calendar Year in which the available surplus power is delivered; and

(ii) The Hourly Powerdex Mid-Columbia index price for the Hour in which the positive Energy Imbalance Service is taken by the Customer. In Hours in which the Mid-Columbia index price is negative, the negative value will be used result in a charge to the Customer for those Hours;

plus:

(iii) An administrative premium of 10 percent will be subtracted from the credited amount or added to the charged amount if the Mid-Columbia index price was negative.

A negative imbalance will be charged as follows:

1. For Hourly negative Energy Imbalance Service less than or equal to 4 MW, the charge will be:

(i) The amount of negative Energy Imbalance Service x (1 x loss compensation percentage under Rate Schedule 109);

multiplied by:

(ii) The Hourly Powerdex Mid-Columbia per kW.h price for the Hour in which the negative Energy Imbalance Service is taken by the Customer. In Hours in which the Mid-Columbia per kW.h price is negative a zero value will be used;

plus:

(iii) The Bonneville Power Authority's (BPA) wheeling rate from B.C.-U.S. Border to Mid-Columbia. per kW.h;

plus:

(iv) An administrative premium of 10 percent.

RATE SCHEDULE 106 - ENERGY IMBALANCE SERVICE (Cont'd)

2. For hourly negative Energy Imbalance Service greater than 4 MW, the charge will be:

   (i) The amount of negative Energy Imbalance Service x (1 x loss compensation percentage under Rate Schedule 109);

   multiplied by the greater of:

   (ii) $50/MWh, or

   (iii) 150 percent of the Hourly Powerdex Mid-Columbia per kWh price for the Hour in which the negative Energy Imbalance Service is taken by the Customer. In hours in which the Mid-Columbia price is negative, a zero value will be used;

   plus:

   (iv) The BPA wheeling rate from B.C.-U.S. Border to Mid-C per kW.h;

   plus:

   (iv) An administrative premium of 10 percent.

NOTE: BPA's wheeling rate is available on the BPA website.

A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017

RATE SCHEDULE 107 - OPERATING RESERVE (OR) - SPINNING RESERVE SERVICE

PREAMBLE: Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. FortisBC must offer this Service when the transmission Service is used to serve load within its Service area. The Transmission Customer must either purchase this Service from FortisBC or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below.

AVAILABILITY: In support of the transmission of Electricity under Rate Schedules 100 and 101.

RATE: $9.31 per mega-watt per Hour of generating Capacity requested for OR - Spinning.

The required amount of Spinning Reserve Service, for a Customer's load located in FortisBC's Service area, depends upon the type of generation serving the load. When the load is served by hydro generation, the required amount of Spinning Reserve Service is a minimum of 2.5% of the Customer's load. When the load is served by thermal generation, the required amount of Spinning Reserve Service is a minimum of 3.5% of the Customer's load.

NOTE: A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017.

RATE SCHEDULE 108 – OPERATING RESERVE (OR) – SUPPLEMENTAL RESERVE SERVICE

PREAMBLE: Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. FortisBC must offer this Service when the transmission Service is used to serve load within its Service Area. The Transmission Customer must either purchase this Service from FortisBC or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below.

AVAILABILITY: In support of the transmission of Electricity under Rate Schedule 100 and 101.

RATE: $9.31 per mega-watt per Hour of generating Capacity requested for OR-Supplemental.

The required amount of Supplemental Reserve Service, for a Customer's load located in FortisBC Service area, depends upon the type of generation serving the load. When the load is served by hydro generation, the required amount of Supplemental Reserve Service is a minimum of 2.5% of the Customer's load. When the load is served by thermal generation, the required amount of Supplemental Reserve Service is a minimum of 3.5% of the Customer's load.

NOTE: A description of the methodology for discounting the Services provided under this Schedule is contained in Section 3 of Electric Tariff Supplement No. 7.

PERMANENT RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission (Commission) Order G-11-17, rates under this schedule, which were made interim by Commission Order G-180-16, are now made permanent, effective January 1, 2017

RATE SCHEDULE 109 - TRANSMISSION LOSSES

APPLICABLE: All transactions under rate Schedules 100 and 101 will incur real power losses as follows:

Wholesale Service - Transmission	6.08%
Wholesale Service - Primary	11.53%
Large Commercial Service - Transmission	6.08%

RATE SCHEDULE 110 – GENERAL WHEELING SERVICE – BC HYDRO

AVAILABILITY: Available to BC Hydro for the Wheeling of electricity over FortisBC's transmission facilities in accordance with the terms and conditions as set forth in Electric Tariff Supplement No. 9.

APPLICABLE: Applicable to the Point of Supply and the Point of Delivery as specified in Electric Tariff Supplement No. 9.

ANNUAL RATE: The annual rate for Wheeling from the Point of Supply to the Point of Delivery, pursuant to Tariff Supplement No. 9, will be adjusted by the annual rate of inflation published by Statistics Canada using the British Columbia Consumer Price Index (all items) for the Month of January in the calendar Year in which the adjustment is made. The base rate is as follows:

Point of Supply to Point of Delivery

On 1 January 2017, $26,118.89 per MVA of Nominated Wheeling Demand

MONTH CHARGE: The Monthly charge will be one twelfth of the above annual rate per MVA of Nominated Wheeling Demand for the Point of Supply.

NOMINATED WHEELING DEMAND: The maximum amount, as determined in Section 4 of Electric Tariff Supplement No. 9, at which FortisBC will Wheel electricity for BC Hydro during a stated year.

EMERGENCY WHEELING: The rate for electricity deliveries that exceed the Nominated Wheeling Demand will be as set forth in Section 6 of Electric Tariff Supplement No. 9.

DEFINITIONS: All terms capitalized above are defined in Electric Tariff Supplement No. 9.

RATE SCHEDULE 111 – WANETA EXPANSION RESIDUAL CAPACITY – BC HYDRO

AVAILABILITY: Available to BC Hydro for the purchase of WAX Capacity in accordance with the terms and conditions as set forth in Electric Tariff Supplement No. 10 until September 30, 2025.

APPLICABLE: Purchased Capacity is deemed to be available to BC Hydro at the Kootenay Interconnection, as specified in Electric Tariff Supplement No. 10.

HOURLY CAPACITY RATE: The Monthly Demand Charge, in $ per kW/Month, will be as determined pursuant to the Power Purchase Agreement (including all rate riders and excluding any taxes) and set out from time to time in BC Hydro's Rate Schedule 3808 or its successor Rate Schedule.

The Hourly capacity rate ($ per MW/Hour) for the Purchased Capacity made available to BC Hydro is the Monthly Demand Charge multiplied by 1000 and divided by 730.

PURCHASED CAPACITY: The amount of WAX Capacity that will be made available to BC Hydro during each Hour of the Term will be the lesser of:

(i) 50 MW; and

(ii) the amount of Residual Capacity (in MW) for that Hour, rounded to one decimal place.

The amounts payable by BC Hydro for each Hour of a Billing Month will be summed, and the sum for all Hours of the Billing Month will be invoiced by FortisBC.

DEFINITIONS: All terms capitalized above are defined in Electric Tariff Supplement No. 10.

Note: The terms and conditions under which service is provided to BC Hydro are contained in the Residual Capacity Agreement, Electric Tariff Supplement No. 10.

Appendix I

RATE HARMONIZATION BACKGROUND

Appendix I-1

1998 JOINT BC HYDRO WKP HARMONIZATION APPLICATION

5 October, 1998

Mr. R.J. Pellatt
Commission Secretary
B.C. Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Dear Mr. Pellatt:

Re: British Columbia Hydro and Power Authority ("BC Hydro") and West Kootenay Power Ltd. - Rate Harmonization

B.C. Hydro and Power Authority ("B.C. Hydro") and West Kootenay Power Ltd. ("WKP") have jointly developed a proposal to include language within their respective transmission tariffs which will harmonize rates between their respective service areas. The purpose and effect of the amendments is to relieve wholesale transmission customers from the requirement to pay both B.C. Hydro's and WKP's wholesale transmission rate by charging only the wholesale transmission rate of the utility whose service area the customer is located within. As described below, the application proposes changes to the wholesale transmission schedules, and not the terms and conditions of access.

Attached as Appendix A are the proposed changes to B.C. Hydro's Schedules 3001 and 3002 which have been highlighted for your convenience. The attached Appendix B contains proposed changes to WKP's Schedules 101 and 102. The gist of these amendments is that for wheeling to points of interconnection between B.C. Hydro and West Kootenay Power, the wholesale transmission rate is set at zero.

WKP and B.C. Hydro agree that these harmonization arrangements should not influence WKP's decision as to whether to source energy under its existing power purchase agreement with B.C. Hydro (Rate Schedule 3808) or from alternative sources. Similarly B.C. Hydro's purchases from WKP under WKP's Rate Schedule 40 should not be influenced. To reflect this principle, the parties have agreed that the various power purchase agreements should be amended to include the additional terms found in the attached Appendix C.

The proposed changes to the power purchase agreements set out in Appendix C should ensure neutrality in WKP's and B.C. Hydro's evaluations of their supply alternatives in most foreseeable circumstances. However, if actual experience after harmonization is introduced leads either party to believe that WKP's or B.C. Hydro's supply decisions are being affected by the harmonization arrangements, the parties will work together to determine what further steps can be taken to ensure ongoing neutrality. Failing agreement, either party may ask Commission approval of further changes as necessary but the parties agree that in any proceeding before the Commission, they will continue to support the principle of neutrality outlined in this letter.

The Commission should note that while the proposed arrangements are neutral as between B.C. Hydro and WKP, they are likely not neutral as between their respective ratepayers. Because the net flow between the two service areas is likely to be into WKP's service area, the effect of the harmonization arrangements will be to reduce the responsibility of WKP customers who purchase energy from sources other than WKP, for the embedded costs of the B.C. Hydro transmission system. WKP customers currently pay their share of those costs through the transmission component of the bundled Rate Schedule 3808. The reverse is true but has a smaller impact for B.C. Hydro's wholesale purchases from WKP. In B.C. Hydro's view the lack of neutrality is an unavoidable consequence of harmonization between the two systems and it will be for the Commission to determine whether the benefits of harmonization are sufficient to justify this impact.

Yours very truly,

Darlene Cathcart
Senior Vice-President
Marketing & Customer Services
British Columbia Hydro and Power Authority

Robert Hobbs
Direct Regulatory and Government Affairs
West Kootenay Power Ltd.

Attachments

c: Robert Hobbs

APPENDIX A

CHANGES TO B.C. HYDRO WHOLESALE TRANSMISSION SERVICE SCHEDULES

(Suggested language is shown shaded)

SCHEDULE 3001: LONG-TERM AND SHORT-TERM FIRM POINT TO POINT TRANSMISSION SERVICE

Rates for Long Term Firm Service

The Reserve Capacity Charge for the Long-Term Firm Service Rate will be up to a maximum price as set out below except where the POD is a point of interconnection between the Transmission System and the transmission system of West Kootenay Power Ltd., in which case the rate shall be zero ($0.00).

Rates for Short Term Firm Service

The posted prices will be above a minimum price and below a maximum price as set out below except where the POD is a point of interconnection between the Transmission System and the transmission system of West Kootenay Power Ltd., in which case the rate shall be zero ($0.00)

SCHEDULE 3002 - NON-FIRM POINT TO POINT TRANSMISSION SERVICE

Rates for Short Term Non-Firm Service

The Transmission Customer shall compensate B.C. Hydro each month for a Reserved Capacity designated at the POR at the posted prices which will be above the minimum price and below a maximum price as set out below except in all cases where the POD is a point of interconnection between the Transmission System and the transmission system of West Kootenay Power Ltd., in which case the rate shall be zero ($0.00).

APPENDIX B

CHANGES TO WEST KOOTENAY POWER LTD. WHOLESALE TRANSMISSION SERVICE SCHEDULES

(Suggested language is shown shaded)

Original Sheet 71

SCHEDULE 101 - LONG-TERM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

Availability: For transmission of electricity on a firm basis from one or more Point(s) of Receipt (POR) to one or more Point(s) of Delivery (POD).

Annual Rate for Long-Term Firm Service:

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 B.C. Hydro and Power Authority.

Monthly Rate:

Wholesale Service-Transmission
A customer charge of $208 per POD to a maximum of $208 in any calendar month.
plus
$2.24 per kVA of Reserved Capacity Billing Demand.

Wholesale Service-Primary
A customer charge of $1,122 per POD to a maximum of $1,122 in any calendar month. plus
$4.35 per kVA of Reserved Capacity Billing Demand.

Large General Service-Transmission
A customer charge of $1,417 per POD to a maximum of $1,417 in any calendar month. plus
$2.37 per kVA of Reserved Capacity Billing Demand.

APPENDIX B - Continued
CHANGES TO WEST KOOTENAY POWER LTD.
WHOLESALE TRANSMISSION SERVICE SCHEDULES

(Suggested language is shown shaded)

Original Sheet 72

SCHEDULE 101 - LONG-TERM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE (cont'd)

Rate for Short-Term Firm Service:

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 the POD is a point of interconnection between the Transmission System and the transmission system of B.C. Hydro and Power Authority.

Minimum Price: $0.002 per kW per hour plus the applicable customer charge.

Maximum Price:

The Transmission Customer shall pay each month for Reserved Capacity designated at the POD at rates not to exceed the applicable charges set forth below:

Monthly Delivery:

Wholesale Service-Transmission
A customer charge of $208 per POD to a maximum of $208 in any calendar month. plus
$3.02 per kVA of Reserved Capacity Billing Demand.

Wholesale Service-Primary
A customer charge of $1,122 per POD to a maximum of $1,122 in any calendar month. plus
$5.87 per kVA of Reserved Capacity Billing Demand.

Large General Service-Transmission
A customer charge of $1,417 per POD to a maximum of $1,417 in any calendar month. plus
$3.20 per kVA of Reserved Capacity Billing Demand.

APPENDIX B - Continued
CHANGES TO WEST KOOTENAY POWER LTD.
WHOLESALE TRANSMISSION SERVICE SCHEDULES

(Suggested language is shown shaded)

Original Sheet 76

SCHEDULE 102 - NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

Availability: For transmission of electricity on a Non-firm basis from one or more Point(s) of Receipt (POR) to one or more Point(s) of Delivery (POD).

Rates for Short-Term Non-Firm Service

Rate for Short-Term Non-Firm Service:

The Transmission Customer shall pay each month for Reserved Capacity designated at the POR at the posted prices which will be above a minimum price and below a maximum price as set out below.

Minimum Price: $0.001 per kW per hour

Maximum Price:
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 B.C. Hydro and Power Authority.

Monthly Delivery

Wholesale Service-Transmission
A customer charge of $208 per POD to a maximum of $208 in any calendar month. plus
$3.02 per kVA of Reserved Capacity Billing Demand.

Wholesale Service-Primary
A customer charge of $1,122 per POD to a maximum of $1,122 in any calendar month. plus
$5.87 per kVA of Reserved Capacity Billing Demand.

Large General Service-Transmission
A customer charge of $1,417 per POD to a maximum of $1,417 in any calendar month. plus
$3.20 per kVA of Reserved Capacity Billing Demand.

APPENDIX C

CHANGES TO POWER PURCHASE AGREEMENTS

WKP Purchases from B.C. Hydro

For the purposes of this clause, and this clause only, capitalized items shall have the same meaning as contained in B.C. Hydro's Tariff Supplement No. 30 - Terms and Conditions applicable to wholesale transmission service.

When the B.C. Hydro Transmission System is used by West Kootenay Power or an agent to transmit power purchased from any person other than B.C. Hydro to serve West Kootenay Power's Native Load Customers, to a Point of Interconnection or to the Point of Supply (as defined in the General Wheeling Agreement between B.C. Hydro and West Kootenay Power dated October 15, 1986), West Kootenay Power shall pay to B.C. Hydro an amount equal to the Hourly Price for Reserved Capacity which would have been payable for transmission of that energy under Rate Schedule 3001, times the amount of energy delivered.

B.C. Hydro Purchases from WKP

For the purposes of this clause, and this clause only, capitalized items shall have the same meaning as contained in West Kootenay Power's Tariff Supplement No. 7 Terms and Conditions applicable to wholesale transmission access.

When the West Kootenay Power Transmission System is used by B.C. Hydro or an agent to transmit power purchased from any person other than West Kootenay Power to serve B.C. Hydro's Native Load Customers at a point of interconnection. B.C. Hydro shall pay to West Kootenay Power an amount equal to the Hourly Price for Reserved Capacity which would have been payable for transmission of that energy under Rate Schedule 101 for Wholesale Service - Primary, times the amount of energy delivered.

Appendix I-2

COMMISSION LETTER DATED OCTOBER 23, 1998

BF Nov. 2/98
Nov 6/98.

BRITISH COLUMBIA UTILITIES COMMISSION

ROBERT J. PELLATT
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
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SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

VIA FACSIMILE

October 23, 1998

Dear Registered Intervenor:

Re: British Columbia Hydro and Power Authority ("B.C. Hydro") and West Kootenay Power Ltd. ("WKP") – Rate Harmonization

On October 5, 1998, B.C. Hydro and WKP jointly submitted a proposal to include language within their respective transmission tariffs which will harmonize rates between their service areas. The purpose and effect of the amendments is to relieve wholesale transmission customers from the requirement to pay both B.C. Hydro's and WKP's wholesale transmission rate by charging only the wholesale transmission rate of the utility within whose service area the customer is located.

In order to determine how to proceed in this matter, the Commission is requesting your views with respect to the following two questions no later than November 9, 1998. First, is a formal public hearing required to dispose of this matter? Second, is it acceptable to treat the rate harmonization proposal as an interim measure subject to review after two years based on the history of activities and the impacts on each utility?

A copy of the Rate Harmonization proposal is attached for your convenience.

Yours truly,

Robert J. Pellatt

DWE/yl
Attachment
cc: Ms. Darlene M. Cathcart
Senior Vice President, Marketing and Customer Services
British Columbia Hydro and Power Authority
Mr. R.H. Hobbs
Director, Regulatory and Government Affairs
West Kootenay Power Ltd.

BCH/Cor/WKP-BCH-WTS;WKP-TAA

PHH ✓
981020
cc: G. Isherwood
R Siddall
B. van Yzerloo

Appendix I-3

COMMISSION ORDER G-12-99

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-12-99

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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

and

Applications by West Kootenay Power Ltd.
and British Columbia Hydro and Power Authority
for Approval of Rate Harmonization on their Transmission Systems

BEFORE:

P. Ostergaard, Chair)
L.R. Barr, Deputy Chair)
K.L. Hall, Commissioner) January 28, 1999
F.C. Leighton, Commissioner)

O R D E R

WHEREAS:

A. The Commission, by Order No. G-29-98, set down a Pre-hearing Conference on West Kootenay Power Ltd.'s ("WKP") then-current Transmission Access Application. During the April 23, 1998 Pre-hearing Conference, attendees identified the need for harmonizing the transmission wheeling rates between WKP and British Columbia Hydro and Power Authority ("B.C. Hydro"). The objective of harmonization is to eliminate rate stacking or "pancaking" – that is, the payment by customers of two transmission wheeling tariffs on transactions where power is moved between utility service areas; and

B. By Letter No. L-19-98, the Commission directed that WKP and B.C. Hydro should work together to develop suitable arrangements and to issue a joint proposal. In the event that no agreement could be reached, then separate proposals were to be filed by each utility. Letter No. L-68-98 extended the date by which the proposals should be filed; and

C. On October 5, 1998, B.C. Hydro and WKP jointly applied to the Commission for approval of a Rate Harmonization proposal to harmonize transmission wheeling rates between their respective service areas. The effect of the proposed tariff and power purchase agreement amendments is to relieve transmission service customers from the requirement to pay both B.C. Hydro's and WKP's transmission wheeling rates by charging only the transmission service rate of the utility within whose service area the customer taking service is located; and

D. On October 23, 1998, the Commission wrote to intervenors registered in either of B.C. Hydro's or WKP's open access proceedings, to elicit views on the disposition of the harmonization proposal; and

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-12-99

E. On December 3, 1998, the Commission provided an information request to B.C. Hydro and WKP to which they jointly responded on January 6, 1999; and

F. The Commission has reviewed the joint proposal between WKP and B.C. Hydro and finds that it should be approved and Reasons for Decision issued.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves the joint B.C. Hydro/WKP rate harmonization proposal subject to review after two years, effective immediately. Reasons for Decision are attached as Appendix A to this Order.

2. B.C. Hydro and WKP are directed to file amended electric tariffs reflecting this decision.

3. B.C. Hydro and WKP are to provide copies of the approved tariffs, this Order and Reasons for Decision to all known participants and interested parties on this matter.

DATED at the City of Vancouver, in the Province of British Columbia, this 4th day of February 1999.

BY ORDER

Peter Ostergaard
Chair

Attachment

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY AND WEST KOOTENAY POWER LTD.
TRANSMISSION RATE HARMONIZATION APPLICATION

REASONS FOR DECISION

1.0 INTRODUCTION

1.1 Background

On April 23, 1998, a pre-hearing conference was held regarding West Kootenay Power Ltd.'s ("WKP") then-current Transmission Access Application. At that conference, discussions took place among WKP, the British Columbia Hydro and Power Authority ("B.C. Hydro"), the British Columbia Utilities Commission ("Commission") staff, and other participants concerning the need to harmonize transmission wheeling rates between WKP and B.C. Hydro. The objective of harmonization is to eliminate rate stacking or "pancaking" — that is, the payment by customers of two transmission wheeling tariffs on transactions where power is moved between utility service areas.

During the pre-hearing conference, there appeared to be agreement that transmission wheeling rate harmonization was desirable, and that WKP and B.C. Hydro should work together to craft a suitable arrangement. By Letter No. L-19-98, the Commission directed WKP and B.C. Hydro to file, by September 18, 1998, a joint letter outlining their common proposal. In the event that no agreement could be reached by that date, separate letters were to be filed by each utility. By Letter No. L-68-98, the Commission granted an extension of the September 18th deadline to October 2, 1998.

On October 5, 1998, B.C. Hydro and WKP filed a joint transmission wheeling rate harmonization proposal with the Commission. On October 23, 1998, the Commission wrote to intervenors registered in either of B.C. Hydro's or WKP 's open access proceedings to elicit views on the disposition of the rate harmonization proposal. In particular, the Commission asked about the need for a formal public hearing and about the acceptability of approval, subject to review after two years. Any responses were to be received by November 9, 1998.

The Interior Municipal Electrical Utilities, the Consumers Association of Canada (BC Branch) et al ("CAC(BC)"), the Bonneville Power Administration, WKP, and the Industrial Customers all agreed that a formal public hearing into this issue was not warranted at this time. In addition, all parties except the CAC(BC) supported adopting the proposal, subject to review after two years. The CAC(BC) argued for a review after just one year.

1.2 Description of the Application

B.C. Hydro and WKP have proposed to harmonize their transmission wheeling rates using a "license plate" approach. Under such a scheme, the transmission customer is charged only the transmission wheeling rate of the utility within whose service territory the customer is located. To accomplish this, WKP's Rate Schedules 101 and 102 and B.C. Hydro's Rate Schedules 3001 and 3002 would be amended so that the transmission rate is set at zero for wheeling to points of interconnection between the two Utilities.

Amendments to various power purchase agreements are also proposed to ensure that electricity trade between the two Utilities is not favoured relative to other suppliers, by the absence of a wheeling charge on energy bought under either B.C. Hydro's Rate Schedule 3808 or WKP's Rate Schedule 40. No changes are needed to the terms and conditions of access for either Utility.

2.0 ISSUES FOR CONSIDERATION

This Application has raised two major areas for Commission consideration. First, the Commission has sought to ensure that the license plate approach to harmonization is appropriate for the provincial circumstance. Second, the Commission has evaluated the prospect of extending harmonization beyond just transmission rates, and into the areas of transmission losses and ancillary services.

2.1 The License Plate Approach

The license plate approach to harmonization can create a transfer of revenue responsibility between the ratepayers of participating utilities. Since most open access transactions in B.C. are expected to run from the B.C. Hydro system to the WKP system, and since these transactions will tend to displace Rate Schedule 3808 transactions – through which WKP ratepayers make their contribution to the B.C. Hydro transmission system – there is likely to be a net transfer of cost responsibility for the B.C. Hydro system toward B.C. Hydro ratepayers and away from WKP ratepayers. B.C. Hydro describes this lack of neutrality as an unavoidable consequence of harmonization between the two systems.

The extent of this revenue shift would be determined by market prices, since WKP 's eligible transmission customers would only leave the Utility's embedded-cost supply when the delivered market price is below WKP's Schedule 40 rate. According to B.C. Hydro and WKP, this would require a market price of less than 2.4 cents per kWh, which the Utilities hold to be unlikely.

For perspective, the extreme case of all WKP's wholesale customers switching to suppliers other than WKP would produce an $8 million revenue loss for B.C. Hydro. In such a case, B.C. Hydro and WKP have said that they would consider establishing a mechanism to collect the lost revenue from WKP customers, where such losses could not be offset by margins from increased market sales.

2.2 Commission Determinations

The Commission supports a license plate approach for its simplicity. As well, the Commission sees few problems with its application as long as the use of wheeling tariffs is relatively low. Still, the license plate approach is probably not a harmonization method that could survive indefinitely, since in a high-use environment the shifting of revenue responsibility would reach unacceptable levels.

Therefore, the Commission accepts that a license plate approach to transmission wheeling rate harmonization is appropriate, subject to review after two years.

2.3 Loss and Ancillary Services Harmonization

Questions have been raised, notably by the Industrial Customers, about the harmonization of losses, something that is not a part of the current proposal. In particular, the Industrial Customers assert that summing the line losses of both Utilities for a cross-boundary transaction would lead to an over recovery of losses (the Industrial Customers argue that if the average losses on each system are 7 percent, for example, then the average losses on a combined system would also be 7 percent, so charging a joint 14 percent is inappropriate). As such, the Industrial Customers have asked the Commission to instruct the Utilities to eliminate this "double recovery".

B.C. Hydro and WKP have stated their belief that rate harmonization is appropriate only for the allocation of embedded costs, since these costs are not affected by individual wheeling transaction. Rate harmonization is not appropriate where additional costs are caused by individual wheeling transactions. The Utilities assert that wheeling transactions impose real line losses on both Utilities, and should correctly be additive – not, as the Industrial Customers appear to suggest, averaged across both systems.

The Utilities take a similar position with respect to ancillary services, suggesting that each utility should charge for the ancillary services that it provides. B.C. Hydro and WKP state, however, that only Scheduling, System Control and Dispatch ("SSCD") and Reactive Supply and Voltage Control ("RSVC") would need to be purchased from both Utilities.

2.4 Commission Determinations

The Commission agrees with the Utilities' position on harmonizing losses and ancillary services. While the average loss rate on a combined WKP/B.C. Hydro system may not be exactly the sum of the individual loss rates, it would not simply be the average of the two rates, either. In any case, a postage stamp approach to losses makes no representations of capturing the real losses of any given transaction, so any inaccuracies created by failing to harmonize system losses are unlikely to be unique in either kind or scope.

Considering that the permanency of a license plate approach to harmonization is open to question, the Commission does not support the investment of further resources to modify the existing proposal. Specifically, attempting what would be a quite complex harmonization of losses does not seem to be a useful expenditure of utility or intervenor resources at this time.

As such, the Commission approves, subject to review after two years, the changes identified as Appendices A, B, and C in the October 5, 1998 Application from WKP and B.C. Hydro.

Appendix J

APRIL 10, 2017 MINISTER'S LETTER TO FBC AND BC HYDRO

APR 10 2017

BRITISH COLUMBIA

Ref: 100212

Ms. Jessica McDonald
President and Chief Executive Officer
BC Hydro
PO Box 8910
Vancouver, BC V6B 4N1

Mr. Michael Mulcahy
President and Chief Executive Officer
FortisBC
Suite 100, 1975 Springfield Road
Kelowna, BC V1Y 7V7

Dear Ms. McDonald and Mr. Mulcahy:

I am in receipt of the British Columbia Utilities Commission (BCUC) Report on the Impact of BC Hydro and FortisBC's Residential Inclining Block (RIB) Rates.

I am impressed with the level of participation by utilities, intervenors and customers in reviewing inclining block rates. The participation rate in this process no doubt represents the level of discussion occurring across the province with respect to electricity and RIB rates.

My colleagues and I have heard from many BC Hydro and FortisBC customers who have received large utility bills, who feel they are being penalized by RIB rates, and do not feel that they have the ability to make a significant reduction in their electricity use. Some customers report bills of over $1,500 in winter months, with the vast majority of that being charged in the higher tier.

We hear from customers who have attempted to make their homes energy efficient, and still see high bills. Customers who choose to heat their homes with electricity to limit their impact on the environment, and customers who simply have no access to natural gas, report that they feel the rate structure is unfair to customers with electric space and water heating. We have also heard from some low-income customers who face a significant burden from the cost of paying their electricity bills.

The RIB rates are not new and have been approved by the BCUC in 2008 for BC Hydro, and 2012 for FortisBC. During the proceedings, and in subsequent reports, the evidence shows that the majority of customers, and in fact the majority of customers without access to natural gas, pay less under these rates, and that these rates create an effective incentive for conservation.

.../2

However, some customers of both utilities have seen significant bill increases due to their electricity consumption. Tier 2 rates for BC Hydro customers are 25% above an equivalent flat rate (ie the residential farm rate), while Tier 2 rates for FortisBC customers are 33% above an equivalent flat rate.

In light of these concerns, I asked the BCUC, in 2015, to report on five questions:

1. Do the residential inclining block rates cause a cross-subsidy between customers with and without access to natural gas services?
2. What evidence is available about high bill impacts on low income customers?
3. What evidence is available about factors that lead to high energy use and, therefore, bill impacts for customers without access to natural gas, including low income customers?
4. What is the potential for existing Demand Side Management (DSM) programs to mitigate these impacts?
5. Within the current regulatory environment, what options are there for additional Demand Side Management programs, including low income programs?

I asked that these questions be the focus of the review and specifically asked that any analysis of higher greenhouse gas emissions, electricity conservation, revenue neutrality resulting from the residential inclining block rates and any analysis of alternative rate structures are best left to existing regulatory processes rather than within the context of this review. Over the last 18 months, utilities and the BCUC managed an extensive consultation process to answer these questions. In addition to organizations that frequently participate, the BCUC heard from many other communities and members of the public who do not typically participate in regulatory proceedings. The detailed feedback from stakeholders and the 669 letters received from communities and individual customers speak to the level of interest among these customers.

Having read the report, I am satisfied that RIB rates do not represent a cross-subsidy between customers. However, many customers are concerned specifically about how tiered rates affect their bills and the difference between tiered rates and flat rates. It is not always clear for a customer who has seen a bill increase to distinguish between the impact of RIB rates on their bill, the general rate increases that have also taken place, and the differences in consumption from one heating season to the next, as the effects can occur at the same time. While the utilities engage through various channels to explain these bill impacts, I am encouraging utilities to consider additional measures to improve the understanding of the impact of these factors to their customers, including through examples of bill impacts of stepped rates for typical examples of different types of customers.

.../3

I am satisfied that the vast majority of low income customers are better off under the RIB rate in both BC Hydro and FortisBC service areas, as outlined in the report. That being said, low income customers, especially the minority with bill impacts of 10% or more under tiered rates, face challenges with their bills. While only about 1% of low income BC Hydro customers see bill increases of 10% or more, nearly 10% of FortisBC customers making less than $30,000 per year do. I note that FortisBC has recently increased its funding for low income DSM programs, and I encourage continued work on these programs.

The evidence submitted on factors that affect energy use confirms that customers who use electricity for space and water heating, and that live in single family homes, are more likely to have high energy consumption. Appliances and conservation choices also play a role for customers of both utilities. Utility evidence also shows that the size of a home is a factor in high energy use. While most homes in both utilities' service areas are less than 2,000 square feet in heated area, the majority of high-use homes are over 2,500 square feet in heated area.

As well as providing utility customers with additional information on flat and stepped rates, I am encouraging BC Hydro and FortisBC to conduct the following:

1. Collect and provide more information to utility customers about the potential impact of appliance and housing types on their bills, in addition to information currently provided on conservation opportunities.
2. Ensure that the information you collect on your customers' end-use includes robust data on customers without access to natural gas, low income customers, high-use customers, and customers who use electricity for space and water heating so that you, and the BCUC, have a clear understanding of rate impacts on those groups.

The BCUC has noted that there are opportunities for additional actions to benefit all customers and particularly for people who use electricity for space and water heating. Since customers without access to natural gas typically use electricity for space and water heating, these actions would be especially beneficial to them. With this context, I am also encouraging FortisBC to:

1. Extend existing programs to offer energy assessments, by certified energy advisors, for those customers who have high bill impacts and for those who use electricity for space and water heating, so that they know why their consumption is high and what effective measures they can undertake to reduce their consumption.
2. Leverage and enhance existing programs to mitigate energy consumption for customers without access to natural gas and low income customers, including those with high bills.

.../4

In the case of BC Hydro, considerable work has already been undertaken to modernize its DSM program offers to increase efficiency and better reflect customer and system needs and these changes are currently being examined by the BC Utilities Commission and interveners as part of the current Revenue Requirements Application proceeding. .

While the BCUC has recently approved continuation of BC Hydro's RIB, I note that FortisBC will be making a rate design application to the BCUC later this year, and BC Hydro will be submitting Module 2 of their Rate Design Application. I understand that BC Hydro is taking this opportunity to examine the potential for optional rates that could provide more choice and flexibility to residential customers. For FortisBC, a full rate design application presents the same opportunity, as well as the opportunity to examine a range of alternative rate designs with price signals for energy efficiency and electrification.

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 electrification.

Sincerely,

WR Bennett

Bill Bennett
Minister

pc: Mr. David Morton
Chair and Chief Executive Officer
British Columbia Utilities Commission

Appendix K

KEREMEOS IRRIGATION LETTER

Keremeos Irrigation District

P.O. BOX220
712 - 6th Avenue
KEREMEOS, B.C.VOX lNO

Phone (250) 499-5651
Fax (250) 499-5696

November 2, 2017

Mr. Corey Sinclair
Manager, Regulatory Affairs
FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, BC V17 7V7

via email: corey.sinclair@fortisbc.com

Dear Mr. Sinclair;

Irrigation Districts have a large capacity and power demands during the irrigation season and a much lower demand during the winter months when irrigation season has ended and the systems only provide water mainly for domestic use for our customers. This leaves substantial reservoir capacity that is not being used during our non-irrigation season.

At present we are billed under the Schedule 60 during the irrigation season and under a non-irrigation season rate during the winter months.

FortisBC has peak load requirements during the day time during the non-irrigation season, particularly during the December/ January time period. Much of this peak load needs to be purchased from other sources at substantial premiums to non-peak load electricity.

If the irrigation districts had the option to utilize a "time of use," rate structure we could reduce this peak load by not pumping water to our reservoirs during the daytime peak load periods in the winter months, allowing Fortis to reduce peak load costs of electricity.

We would like to request that FortisBC incorporate the option to allow Irrigation Customers to utilize "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.

Sincerely,

KE~~-

Roger Mayer
Board Chair

RM/ceh

Appendix L

2017 PROPOSED RATE CHANGE SUMMARY

FortisBC Inc. Fully Bundled Rates

Rate Class	Code	Current FortisBC Rates						Proposed FortisBC Rates					
		Basic Charge ($/month)	Energy Rate (cents/kWh)		Demand Rate ($/kVA)			Basic Charge ($/month)	Energy Rate (cents/kWh)		Demand Rate ($/kVA)		
Residential RCR[1]	RS01	16.05	Tier 1	10.117	n/a			16.58	Tier 1	10.394	n/a		
			Tier 2	15.617					Tier 2	14.915			
Residential Exempt	R03	18.70	11.749		n/a			18.70	11.749		n/a		
Small Commercial	RS20	19.40	10.195		n/a			23.00	10.000		n/a		
Commercial	RS21	16.48	Tier 1	8.663	7.72			54.00	6.875		10.22		
			Tier 2	7.191									
Large Commercial - Primary	RS30	945.04	5.571		9.19			945.04	5.571		9.19		
Large Commercial - Transmission	RS31	3116.03	5.516		Wires	PS		3195.00	5.367		Wires	PS	
					4.93	2.77					4.93	3.45	
Irrigation	RS60	20.06	7.259		n/a			22.09	7.240		n/a		
Primary Wholesale	RS40	2645.03 / POD / mo.	5.441		Wires	PS		2645.03 / POD / mo.	5.441		Wires	PS	
					8.98	4.82					8.98	4.82	
Transmission Wholesale	RS41	5978.48	4.501		Wires	PS		5978.48	4.501		Wires	PS	
					6.34	4.77					6.34	4.77	

Figures in red are higher than the equivalent current rate. Figures in green are lower than the equivalent current rate.

[1] Proposed RCR Rate shown is for the first year of the phase-in period.

Point-to-Point Transmission Service					
	Current Rates			Proposed Rates	
	Large Commercial Service Transmission	Wholesale - Primary	Wholesale - Transmission	Transmission	Primary
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

Ancillary Services							
			Current Rates			Proposed Rates	
			Large Commercial Service Transmission	Wholesale - Primary	Wholesale - Transmission	Primary	Transmission
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 service required per Tariff	$13.62			$9.31	
Transmission Losses	109		6.08%	11.53%	6.08%	4.26%	2.86%