BC Hydro
Power smart

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December 18, 2015

Ms. Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
2015 Rate Design Application (2015 RDA)

In accordance with BCUC Order G-156-15A (Exhibit A-6), BC Hydro submits its responses to Round 1 information requests (**IRs**) as follows:

Exhibit B-5	Responses to BCUC and Intervener IRs (Public Version) (Except responses to **BCUC IR 1.43.1** and Commercial Energy Consumers Association of British Columbia (**CEC**) **IRs 1.7.1**, **1.7.1.1**, **1.7.1.1.1**, **1.7.1.1.2** and **1.8.1)**
Exhibit B-5-1	Responses to BCUC and Intervener IRs (Confidential Version)

BC Hydro advises that responses to the following IRs will be provided at the RDA procedural conference on January 12, 2016 for the following reasons:

BCUC IR 1.43.1	On December 15, 2015 BC Hydro sent a draft of this response, which concerns BC Hydro's Residential E-Plus proposal, to the E-Plus Homeowners Group (intervention application is Exhibit C10-1) for comment
CEC IR 1.7 series, CEC IR 1.8.1	These IRs ask about BC Hydro's expectations concerning potential liquefied natural gas (**LNG**) load since approval of the 2013 Integrated Resource Plan in November 2013. The issue of LNG load is potentially relevant to the energy Long-Run Marginal Cost. Additional time will permit BC Hydro to provide more fulsome responses

BC Hydro takes the opportunity to note the following:

1. **Confidential IR Responses** - As provided by section 42 of the B.C. *Administrative Tribunals Act* and section 1 of the Commission's Confidential Filings Practice Directive, BC Hydro requests confidential filing with the Commission for responses and/or attachments to responses to the following IRs: British Columbia Old Age Pensioners' Organization *et al* (**BCOAPO**) IR 1.183.1; BCUC IRs 1.124.1, 1.127.2 and 1.128.1; and CEC IR 1.84.1. The reason for each request is set out in the public version of each response.
2. **IR Response Adequacy** - BC Hydro declined to respond to a number of intervener IRs requesting information concerning matters such as cost recovery issues, which should be addressed as part of BC Hydro's F2017 Revenue Requirement Application (**RRA**) to be filed with the Commission in February 2016; BC Hydro's Residential Demand Side Management (**DSM**) programs, which are either premature if they are in scope for purposes of responding to the B.C. Minister of Energy and Mines' letter of July 6, 2015 concerning the Residential Inclining Block rate report (**Minister RIB Report Letter**) or should be addressed as part of BC Hydro's DSM expenditure schedule determination request to be filed contemporaneously with or as part of the F2017 RRA; and RDA Module 2 issues such as Non-Integrated Area rate design. In each case, the basis is set out in the IR response. Consistent with past practice, BC Hydro requests that interveners who have issues regarding the adequacy of responses to their IRs contact BC Hydro counsel, Craig Godsoe, prior to taking any formal steps with the Commission. Craig Godsoe can be reached at 604-623-4403 or craig.godsoe@bchydro.com.
3. **Electric Tariff Amendments** – In section 8.5 of Exhibit B-1, BC Hydro stated that it would file a copy of the Electric Tariff with BC Hydro's proposed changes as part of BC Hydro's responses to the first round of IRs. BC Hydro will submit its proposed amendments to the Electric Tariff on or before Tuesday, December 22, 2015.
4. **Minister RIB Report Letter** – BC Hydro's position concerning Questions 4 and 5 of the Minister RIB Report Letter is set out in its responses to BCUC IR 1.51.1 and BCOAPO IR 1.102.1. In BC Hydro's view, it is premature to be undertaking review of BC Hydro's low income and other Residential DSM programs at this time for purposes of Questions 4 and 5 because it has not been established that the RIB rate results in bill impacts of 10 per cent or greater on either BC Hydro's low income customers or customers without access to natural gas.

BC Hydro requests that the Commission make the following two RIB Report Letter-related methodology decisions prior to the RDA procedural conference:

- Confirm BC Hydro's proposal in section 5.5.1 of Exhibit B-1 to use Statistics Canada's Low Income Cut-Off as the method for defining low income customers. No RIB Report-related participant opposes this proposal. FortisBC Inc. (**FortisBC**) supports this proposal;
- Confirm BC Hydro's proposal in section 5.5.3 of Exhibit B-1 to use a community approach to define "access to natural gas". It appears to BC Hydro that no RIB Report-related participant opposes this proposal, although this is less clear than with

respect to the method for defining low income customers. FortisBC supports this proposal. The list of communities in BC Hydro's service area without access to natural gas is found in BC Hydro's response to BCUC IR 1.48.2, which may be revised through additional discussion with FortisBC. In BC Hydro's view, the Commission can endorse the community approach even if there are revisions to the community list.

Confirmation of these two methodologies is required for purposes of moving forward with BC Hydro's report to the Commission concerning the RIB rate, and in particular to undertake modelling of the RIB rate/flat rate impacts on customers without access to natural gas as part of the RDA Round 2 IR process.

Finally, the Commission by letter dated November 10, 2015 granted BC Hydro the opportunity to respond to RIB Report-related participant methodology submissions (Exhibit A-6 in the RIB Report proceeding). BC Hydro confirms that it provided this reply in responses to RDA BCUC IRs 1.46.2 through to 1.51.6.

For further information, please contact Gordon Doyle at 604-623-3815 or by e-mail at bchydroregulatory@bchydro.com.

Yours sincerely,

Original signed

Tom Loski
Chief Regulatory Officer

cg/af

Enclosure

Copy to: BCUC (BC Hydro 2015 Rate Design Application) Registered Intervener Distribution List.

Glossary of Commonly Used Terms and Abbreviations in Information Responses

A

ABSBC	Accenture Business Services of British Columbia
aMW	Average megawatt; The average number of megawatt-hours over a specified time period
AMPC	Association of Major Power Consumers of British Columbia
Apt	Apartment
A/R	Accounts receivable
ATA	*B.C. Administrative Tribunals Act*
AUC	Alberta Utilities Commission

B

B.C.	British Columbia
BCOAPO	British Columbia Old Age Pensioners' Organizations *et al*
BCSEA	BC Sustainable Energy Association and Sierra Club British Columbia
BCTC	British Columbia Transmission Corporation
Commission	British Columbia Utilities Commission
BPA	Bonneville Power Administration
Burrard	Burrard Thermal Generating Station

C

CAPP	Canadian Association of Petroleum Producers
CARC	Class Average Rate Change
CBL	Customer Baseline Load – a measure of historical consumption used for BC Hydro's Transmission Service stepped rate (RS 1823), expressed in kWh
CEA	B.C. *Clean Energy Act*
CEBC	Clean Energy BC

CEC	Commercial Energy Consumers Association of British Columbia
CFL	Compact fluorescent lamp
CP Demand	Coincident peak; the level of demand of a customer or customer class at the time of system peak demand
Commission	British Columbia Utilities Commission
Commission RIB Report Methodology Letter	Commission letter dated 17 August 2015; copy available at Exhibit B-1, Appendix C-1D
COPE 378	Canadian Office and Profession Employees Local 378
COS	Cost of Service – a study that functionalizes, classifies, and allocates BC Hydro's costs to rate classes
COS Consultants	Cuthbert Consulting, Inc. and NewGen Strategies and Solutions, LLC
COS Methodology Review	*Final Report: Cost of Service Methodology Review*, 20 December 2013; copy at Exhibit B-1, Appendix C-2A
CPCN	Certificate of Public Convenience and Necessity
CPR	Conservation Potential Review
CPUC	California Public Utilities Commission

D

DARR	Deferral Account Rate Rider
DCAT	Dawson Creek/Chetwynd Area Transmission Project
DSM	Demand Side Management
DSM Regulation	Demand-Side Measures Regulation, B.C. Reg. 326/2008

E

E3	Energy & Environmental Economics, Inc.
ECAP	BC Hydro's Energy Conservation Assistance Program
EFT	Electronic funds transfer
EH	Electric heat
EPA	Electricity Purchase Agreement

ERP	BC Hydro Energy and Resource Planning
ESA	Electricity Supply Agreement (TS 5)
ESK	BC Hydro's Energy Savings Kits
EV	Electric Vehicle
Exhibit B-1	BC Hydro's 2015 Rate Design Application to the BCUC

F

F	Fiscal Year – BC Hydro's fiscal year ending March 31. Dates marked with an F refer to the year ending March 31 in the year given.
F2014 LGS and MGS Evaluation Report	*F2014 Evaluation of the Large and Medium General Service Conservation Rates* report; Copy at Appendix C-4A of Exhibit B-1
FACOS	Fully Allocated Cost of Service
FMA	Field Metering Analyst
FNEMC	First Nations Energy & Mining Council
FNG	Fort Nelson Generating Station
FNOD	Final Notice of Disconnection
FOIPPA	B.C. *Freedom of Information Request and Protection of Privacy Act*
FortisBC	FortisBC Inc.
FTE	Full Time Equivalent

G

GHG	Greenhouse gas – any of the atmospheric gases that contribute to climate change such as water vapour, methane, or carbon dioxide
GRTA	Generation Related Transmission Assets

GWh	Gigawatt-hour – one billion watt-hours or one million kilowatt hours of Electric Energy being an amount of Electric Energy that will serve about 100 residential customers for one year

H

Heritage Contract Report	Commission's October 2003 *Heritage Contract and Stepped Rates Report and Recommendations*
HLH	High Load Hours, calculated as set out in the applicable rate schedule or other tariff document

I

IEP/LTAP	BC Hydro's 2006 Integrated Electricity Plan/Long-Term Acquisition Plan
IEPR	2013 Industrial Electricity Policy Review
IFRS	International Financing Reporting Standards
IPP	Independent Power Producer
IR	Information Request
IRP	BC Hydro's 2013 Integrated Resource Plan
ISD	In-Service Date
IT	Information Technology
IVR	Interactive Voice Response

K

kV	Kilovolt - one thousand volts. Volt is the basic unit of measurement of electromotive force, the force required to change the random motion of electrons into an electric current
kV.A	The product of the effective volts across the terminals of a circuit and the effective amperes through it, divided by 1,000. A kilovolt ampere is equal to 1,000 Volt-amperes
kW	A kilowatt is equal to one thousand watts; the commercial unit of measurement of Electric Power. One kilowatt is required to light ten 100-watt light bulbs

kW-year	Kilowatt-year
kWh	Kilowatt-hour – The amount of energy delivered in one hour, when delivery is at a constant rate of one kilowatt.; on average residential customers in B.C. use about 10,000 kWh per year

L

LEAP	Ontario Low Income Energy Assistance Program
LED	Light-emitting diode
LGIC	Lieutenant Governor in Council
LGS	Large General Service rate class for BC Hydro customers with a billing demand of at least 150 kW or greater or use more than 550,000 kWh of electricity per year
LI	Low income
LICO	Low-income cut-off, established by Statistics Canada
LLH	Low Load Hours, calculated as set out in the applicable rate schedule or other tariff document
LNG	Liquefied Natural Gas
LRB	Load-Resource Balance
LRMC	Long-Run Marginal Cost

M

MABC	Mining Association of B.C.
MEM	B.C. Ministry of Energy and Mines
MEM Policy Letter	B.C. Ministry of Energy and Mines 17 September 2015 letter to BC Hydro, copy at Appendix C-1C of Exhibit B-1
MGS	Medium General Service rate class for BC Hydro customers with a billing demand between 35 kWh and 150 kWh and use less than 550,000 kWh of electricity per year
Mid C	Mid-Columbia; Wholesale electricity trading hub located in the U.S. Pacific Northwest
Minister	B.C. Minister of Energy and Mines

Minister RIB Report Letter	B.C. Minister of Energy and Mines 6 July 2015 letter to the Chair of the Commission; Copy at Appendix C-1D of Exhibit B-1
MPUB	Manitoba Public Utilities Board
MSDSI	B.C Ministry of Social Development and Social Innovation
MVAr	Mega Volt Ampere Reactive - One million volt ampere reactive
MW	Megawatt – one million watts or one thousand kilowatts
MWh	Megawatt hour
MyHydro	BC Hydro on-line tool for customer accounts

N

NCP Demand	Non-Coincident; The maximum demand of a customer or customer class during the billing period, regardless of when the system peak occurs.
New Westminster New West	City of New Westminster
NEU	City of Vancouver Neighbourhood Energy Utility
NIA	Non-Integrated Area – BC Hydro service areas that are not connected to the transmission grid. Local diesel or hydroelectric generation supplies power to these areas
NSA	Negotiated Settlement Agreement
NSF	Non-sufficient funds
NSP	Negotiated Settlement Process

O

OEB	Ontario Energy Board
OH	Overhead
OIC	Order-in-Council
O&M, OMA	Operations, maintenance and administration

P

PLT	BC Hydro power line technician
Powerex	Powerex Corp.
PPA	BC Hydro-FortisBC Power Purchase Agreement
PRG	Prince Rupert Generating Station

R

R/C Ratio	Revenue to Cost ratio – calculated by dividing a rate class' revenue by assigned costs as determined by a COS study
Rate Rebalancing Amendment	B.C. reg. 140/2015, amending section 9 of Direction No. 7 to the Commission; refer to pages 2-7 and 2-8 of Exhibit B-1 for a description
RDA	Rate Design Application
RDR	Remote Disconnection / Reconnection: The disconnection or reconnection of an electrical service at a customer's meter using functionality within SMI meters. RDR is triggered remotely and does not require the meter to be physically disconnected on-site
REUS	Residential End-Use Survey
Rev 6	Revelstoke Unit 6
RIB	Residential Inclining Block rate
2013 RIB Evaluation Report	*Evaluation of the Residential Inclining Block Rate: F2009-F2012*, copy at Appendix C-3B of Exhibit B-1
RRA	Revenue Requirement Application
RS	Rate Schedule
RTP	Real time pricing rate

S

SCGT	Simple Cycle Gas Turbine - A stand-alone generating plant that uses combustion gases to propel a turbine similar to a jet engine connected to an electrical generator
SDA	Substation Distribution Assets
SFD	Single family dwelling
SFU	Simon Fraser University
SGS	Small General Service rate class for BC Hydro customers with a billing demand of less than 35 kW
SLR	Standard labour rate
SMI	Smart Metering and Infrastructure

T

T&D	BC Hydro Transmission and Distribution
TOU	Time-Of-Use rate; a rate that prices electricity according to the season or time of day that it is used
TRC	Total Resource Cost test
TS	Tariff Supplement
TSR	Transmission Service Rates

U

UBC	University of British Columbia
UCA	B.C. *Utilities Commission Act*
UCC	Unit Capacity Cost
UEC	Unit Energy Cost
UG	Underground

V

VAr	Voltage-Ampere reactive

W

W	A watt is the basic unit of “resistive” electrical power
WACD	Weighted Average Cost of Debt

X

XLGS	Potential class of large LGS customers with demand greater than 2,000 kV

Y

YECL	Yukon Electrical Co Ltd.
YVR	Vancouver Airport Authority

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November 10, 2015

BC HYDRO 2015 RATE DESIGN
EXHIBIT A-5

Mr. Tom Loski
Chief Regulatory Officer
Regulatory & Rates Group
British Columbia Hydro and Power Authority
16th Floor – 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Mr. Loski:

Re: British Columbia Hydro and Power Authority
2015 Rate Design Application

Further to your September 24, 2015 filing of the 2015 Rate Design Application and the Regulatory Timetable set out in Order G-166-15, enclosed please find Commission Information Request No. 1. In accordance with the Regulatory Timetable, please file your responses no later than Friday, December 18, 2015.

Yours truly,

Erica Hamilton

kbb
Enclosure
cc: Registered Interveners

TABLE OF CONTENTS **PAGE**

A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION 2

B. CHAPTER 3 – COST OF SERVICE 8

C. CHAPTER 4 – RATE CLASS DETERMINATION 18

D. CHAPTER 5 – RESIDENTIAL RATE DESIGN 18

E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN 27

F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN 43

G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS 54

A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

1.0 Reference: Exhibit B-1, Application, Section 1.1.3 Orders Sought, pp. 1-5 and 1-11 BC Hydro seeking interim rate orders

On page 1-5, BC Hydro says it will seek interim rate orders, to be effective April 1, 2016, when filing the F2017 revenue requirement application (RRA) in late February 2016 and that its request will include an interim order increasing the RIB rate pricing elements in accordance with the requested RIB Pricing-Principles. On page 1-11, BC Hydro says that it would be requesting an interim rate order for the rate schedule (RS) 1823 F2017-F2019 pricing principles. No such requests for the medium general service (MGS) and large general service (LGS) are noted by Commission staff given that BC Hydro is proposing a flat energy charge for these rates.

1.1 Given the critical importance of pricing principles in the design of conservation rate structures and the overall intent of the rate structures to encourage conservation, would the two interim rate order requests that combine RRA rate increase and rate design pricing principles create customer confusion by distorting the price signals of the conservation rate structures? Please describe the benefits and disbenefits perceived by BC Hydro in requesting these interim rate orders.

2.0 Reference: Exhibit B-1, Application, Section 2.2, pp. 2-6 and 2-14 Legal regime

On page 2-6 BC Hydro says: "The net result in BC Hydro's view is that the Commission may, but is not obliged to, consider and be guided by the British Columbia's energy objectives, subject to the proviso that in the event of a conflict between an energy objective and a rate-setting provision of the [*Utilities Commission Act* (UCA)], the latter must prevail."

On page 2-14, BC Hydro says:

> At Workshop 8a, BC Hydro set out its position that Policy Action No. 4 of the 2007 Energy Plan does not oblige the Commission to ignore the eight Bonbright rate design criteria in favour of a conservation objective or to prioritize the Bonbright efficiency criterion over the other seven criteria. BC Hydro implemented an inclining block rate for its Residential customers in October 2008 (the RIB rate; refer to section 2.3.1.6 below). BC Hydro also explored the possibility of inclining block rates for its General Service customers, but as noted in Chapter 6 of the Application, BC Hydro concludes such rate structures are not viable given the heterogeneous nature of each of the SGS, MGS and LGS rate classes. BC Hydro also explored optional interruptible rates and what is referred to as an optional 'Efficiency Rate Credit' for General Service customers, and an optional clean energy credit for its Residential customers. As described in section 1.5.2 of the Application, BC Hydro will address optional rates for General Service and Residential customers as part of 2015 [Rate Design Application (RDA)] Module 2.

2.1 Please identify any of the energy objectives in the *Clean Energy Act* that are in conflict with BC Hydro's rate design proposal.

2.2 While BC Hydro argues that the Commission is not obligated to be guided by the BC government energy objectives, would BC Hydro agree that the Commission should consider and give

significant weight to those energy objectives? Why or why not?

2.3 Are there any government energy objectives that are in conflict with the eight Bonbright criteria? If so, how should the Commission weigh the competing objectives and criteria? Why?

2.4 With respect to a possible General Service class "efficiency rate credit" to be considered in module 2, what impact would such an incentive have in support of BC Hydro's proposed flat energy and flat demand charges for MGS and LGS customers? For example, if the efficiency rate credit were to incent efficiency and conservation, one might expect that to provide added support for the flat rate proposals since the "efficiency rate credit" might satisfy the efficiency and conservation concerns.

3.0 Reference: Exhibit B-1, Application, Section 2.2.2.1 Postage Stamp Rates, pp. 2-9 and 2-10 Postage stamp rates

On page 2-9, BC Hydro says that postage stamp rates are a method of cost allocation and that the underlying premise is that all customers jointly develop electricity resources and should equally share in the costs. It further describes the postage stamp rate as a fundamental BC government rate design policy, subject only to two discrete and generally accepted exceptions such as limits on the cost of new extensions and Zone II rate design.

3.1 Is it more accurate to describe postage stamp rates as a method of revenue collection as opposed to cost allocation?

3.2 On page 1-11, BC Hydro requests a final order approving a revision, among other things, to the definition of High Load Hours (HLH) to provide BC Hydro discretion to determine the HLH periods that will apply based on a customer location/region which affords BC Hydro the possibility to curtail. Is this another exception to the postage stamp rates?

3.3 Is RS 1852 (Modified Demand Transmission) an exception to the postage stamp rate because its availability is location specific?

4.0 Reference: Exhibit B-1, Application, Section 2.2.3.3, Customer focus groups, pp. 2-23, and 2-25 Bill understanding

On page 2-23 BC Hydro states that: "…most (residential) participants were aware of the total amount of their electricity bills as opposed to the RIB rate structure; and most participants reject a three step rate as too complicated." And on page 2-25 BC Hydro states: "Most (LGS/MGS) customers reportedly look at their electricity bills, but this is mainly in regards to total dollar amount."

4.1 Given BC Hydro's preferred rate structure for the Residential class is the status quo, what further actions can BC Hydro take under the status quo scenario to improve customers' understanding of their bills to promote the rate design objectives of efficiency and conservation? Are there any promotional materials being contemplated?

5.0 Reference: Exhibit B-1, Application, Section 2.3.1.4;
2005 Transmission Service Rate Application, p. 2-36, Footnote 74
Commission jurisdiction to review exempt customers

Footnote 74 on page 2-36 indicates that the exemption customers from the transmission stepped rate originally extended to Aquila, now FortisBC Inc. In May 2013, BC Hydro applied to the Commission to replace the Power Purchase Agreement with FortisBC Inc. under RS 3808.

5.1 Given BC Hydro's comment on page 2-16 that the Commission can only be given jurisdiction to review and make recommendations concerning exempt entities through a section 5 UCA inquiry review process and only the Lieutenant Governor in Council can refer this matter to the Commission under section 5 of the UCA, please provide a brief history of how FortisBC Inc. became separated from the exempt group.

6.0 Reference: Exhibit B-1, Application, Sections 1.5 and 2.4,
Rate Assessment Methodology, pp. 1-20, 2-37, 2-56 – 2-57 and 2-61
Bonbright criteria weighting

Tables 1.2 and 2.7 provide Bonbright rate design criteria and BC Hydro's application of the criteria. "In section 1.5.1 of the Application, BC Hydro set out that it prioritizes the Bonbright customer understanding and acceptance, stable rates for customers, and fair apportionment of costs among customers criteria for purposes of 2015 RDA Module 1."

On page 2-37 BC Hydro states that: "The 2007 RDA was BC Hydro's first comprehensive RDA since 1991."

6.1 How have BC Hydro's experiences since 2007 modified its interpretation and priorities of the eight Bonbright rate design criteria on Table 2.7? For example, natural gas prices, electricity market prices and differentials, self-sufficiency, reduced Long-Run Marginal Cost (LRMC), and government policy.

6.2 BC Hydro notes that the eight Bonbright criteria presented in Table 2.7 are presented in no particular order. For Table 1.2, three of the Bonbright criteria are said to be "prioritized criteria." Please explain how Table 1-2 and Table 2-7 relate to each other.

6.3 Have BC Hydro's experiences with the lack of conservation achieved under the MGS and LGS rate structures downgraded the efficient price signal rate design priority not only for the GS class but also for the Residential and Transmission classes? Please explain.

6.4 Is there value in prioritizing some Bonbright criteria over others in the context of the overall Rate Design Application? In other words, why would it not be more reasonable to consider that some Bonbright criteria might be more relevant than others when assessing a particular aspect of the Application, but that the most relevant criteria might change depending on the particular issue being reviewed? Please explain.

7.0 Reference: Exhibit B-1, Application, Section 2.3.1.5 2007 RDA, p. 2-39
10 Percent maximum bill impact threshold

On page 2-39, BC Hydro says that in the 2007 RDA, it was criticized for excluding RRA increases from the

10 percent maximum bill impact test, and in response, the 10 percent bill impact test used to develop the 2015 RDA is inclusive of RRA increases.

7.1 Does BC Hydro accept that customer response from general rate increases will, all things being equal, result in natural conservation whereas customer response from rate design changes such as stepped rate structure, all things being equal, will result in demand-side management (DSM) conservation savings? If yes, does including RRA increase when analyzing bill impact in a rate design study blur the definition of the two types of conservation savings?

7.2 Please provide a table showing two columns of data, historical and projected, between F2006 to F2019: Column 1 showing annual RRA increases and Column 2 showing the room for rate design increases under the 10 percent bill impact threshold.

8.0 Reference: Exhibit B-1, Application, Section 2.3.2.2 LRMC, p. 2-46
Energy LRMC

On page 2-46, BC Hydro defines LRMC as the change in the long-run cost resulting from a change in the quantity of output produced. In short, LRMC represents the price of the most cost-effective way of satisfying incremental customer demand where existing resources are insufficient to meet that demand.

8.1 The energy LRMC was set out in the 2013 IRP. Please explain if the results of the conservation savings from the MGS and LGS Evaluation Report, which were considerably less than forecast, had been incorporated into the resource stacks and resource load balance in the 2013 IRP. If not, how would the difference between forecast and actual MGS and LGS conservation savings affect the estimate of the energy LRMC, if at all?

9.0 Reference: Exhibit B-1, Application, Section 2.3.2.2, p. 2-52 and
Integrated Resource Plan (Appendix 3B: Site C Information Sheet)
Energy LRMC

The Application states that DSM and Energy Purchase Agreement (EPA) renewals are marginal resources until about 2030, after which BC Hydro would require green-field clean or renewable independent power producers (IPPs). According to BC Hydro's Integrated Resource Plan (Appendix 3B: Site C Information Sheet), the estimated in-service date for Site C is fiscal 2024.

9.1 It doesn't appear that BC Hydro included Site C costs in its calculation of LRMC. If not, why not?

9.2 If Site C costs were included in the calculation of LRMC, what would the inflation-adjusted range in the Energy LRMC be?

10.0 Reference: Exhibit B-1, Application, Section 2.3.2.2, Tables 2-5 and 2-6, pp. 2-53 and 2-54
Energy LRMC

On page 2-53, BC Hydro states that: "BC Hydro reviewed distribution losses and finds that they are still reasonably close to 6 per cent of distribution load."

10.1 Based on this statement one would expect the difference between tables 2.5 and 2.6 to be, uniformly 6 percent, but this does not appear to be the case for all years. Why not?

11.0 Reference: Exhibit B-1, Application, Sections 2.3.2.2 & 2.3.2.3 LRMC, p. 2-54 Table 2-6 Inflation adjusted range in energy LRMC for distribution service

On page 2-54, BC Hydro states that for purposes of this Application and as identified in the 2013 IRP, the LRMC for capacity resources is based on Revelstoke 6, the most cost-effective generation capacity on a unit cost basis.

11.1 On page 2-55, BC Hydro summarizes the grounds advanced by participants in the pre-filing workshops for including a generation capacity value in the energy LRMC. Both grounds involved the RIB rate. Please confirm that the small general service (SGS) rate structure also includes no demand charge. Please also confirm that the demand charge in SGS is recovered, in part, through the energy rate.

11.2 Please replicate Table 2-6 with a column that includes capacity LRMC.

The Application states on page 2-54 that the 2013 IRP shows that the unit capacity cost (UCC) of natural gas-fired simple cycle gas turbine generators (SCGTs) would be $88/kW-year. Table 3-27 on page 3-75 of the 2013 IRP shows the UCC cost of SCGTs at two locations would be $84 or $180.

11.3 Please explain the discrepancy between the IRP cost estimate and that cited in the Application.

12.0 Reference: Exhibit B-1, Application, Section 2.3.2. Current Environment Context, p. 2.54 LRMC for Distribution Service; Commission Reasons for Decision to Order G-124-08

Commission Reasons for Decision to Order G-124-08 on the BC Hydro RIB Rate Application states: "BC Hydro estimated that about three to four cents/kwh … ought to be added to the marginal cost of new energy supply for the purpose of establishing the marginal rate ceiling …" (pp. 92, 93)

12.1 Please estimate (in $/k@-year and cents/kwh equivalent) the F2016 BC Hydro 'transmission LRMC' and 'network (transmission plus distribution) LRMC for load located in the Lower Mainland.

12.2 Does BC Hydro consider that a reasonable proxy for the 'network LRMC' could be BC Hydro's embedded network costs? Please explain.

12.3 Please explain what the 'three to four cents/kwh' in BC Hydro's 2008 RIB proceeding was intended to represent, and if BC Hydro has improved the accuracy of this costing data for the 2015 RDA.

12.4 Please updated table 2-5 and 2-6 in the Application to show BC Hydro's "total LRMC" (i.e., energy, capacity and network) estimates.

13.0 Reference: Exhibit B-1, Application, Section 2.3.2.3, p. 2-55, and Section 5.2.5.1, p. 5-34, Fig. 5-18 Capacity LRMC and Step 2 RIB pricing

On page 2-55, the Application notes that while the RIB is an energy conservation rate, it delivers anticipated capacity savings, and states that "BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction."

BC Hydro also references the 2011 RIB Re-Pricing Decision where the Commission stated that the RIB Step 2 rate should be based on a "price signal for customers to understand *what is happening to the cost of energy* they will consume in the future" (emphasis added by BC Hydro).

13.1 Notwithstanding the Commission's previous findings on the issue, and the fact that the RIB Step 2 rate is generally referred to as the Step 2 energy rate, does naming the rate an "energy rate" or an "energy conservation rate" reflect an overly precise view of the rate, given the anticipated capacity savings, and if so should a capacity value be included in the LRMC? If not, why not?

Figure 5-18: Requested RIB Rate Pricing Principles Option 1 shows that for the period F2017–F2019 the Step 2 rate is approximately equal to or above an LRMC that includes a capacity cost based on the UCC of Revelstoke Unit 6.

13.2 Please confirm that, even though the proposed Step 2 rate approximates the LRMC that includes a capacity cost, BC Hydro does not agree that including a capacity cost in the LRMC for the purpose of setting a Step 2 rate is appropriate (for the reasons set out in section 2.3.2.3), and that the proposed step 2 rate is the result of its proposal to maintain the current differential between the Step 1 and Step 2 energy rates, rather than the use of an LRMC that includes a capacity cost as a reference point.

14.0 Reference: Exhibit B-1, Application, Section 2.4, Rate Assessment Methodology, pp. 2-58 and 2-59; Section 5, 2.5.1, Figures 5-20 to 5-22
Bonbright Criteria – Ten percent bill impact test

> …BC Hydro uses the 10 per cent bill impact test as an amber signal rather than a stop-or-go constraint. For example, BC Hydro believes that it is acceptable for bill impacts to exceed 10 per cent per year where the absolute dollar value of the increases is very small.
>
> …
>
> Some stakeholders suggested using the 95 percentile or 90 percentile. After calculating the bill impacts of all customers and then sorting from the highest percentage increase to the lowest percentage increase, the customer that is 95 per cent of the way up the ranking would be the 95th percentile customer on bill impact. In BC Hydro's view, applying the 10 per cent test to any threshold level other than the most adversely impacted customer will lead to definitional problems or will have unintended consequences.

14.1 Please explain why BC Hydro considers that the 10 percent test should be applied only to the most adversely impacted customer when that criterion may impede progress towards fair pricing for the vast majority of a rate class.

14.2 Please explain or discuss the "unintended consequences."

14.3 Would BC Hydro agree that a situation where it might be appropriate to use a 90th or 95th percentile customer in the bill impact test might be where the data shows a significant discontinuity at the extreme ends of the population distribution (i.e. where the energy consumption of the 100th percentile customers was significantly higher or lower than any other customer)? If not, why not?

14.4 Referring to the plots in Figures 5-20 to 5-22, in BC Hydro's view does the consumption pattern of residential customers show enough continuity in the distribution of energy consumption to support relying on the 100th percentile rather than the 90th or 95th percentile? Please explain why or why not.

B. CHAPTER 3 – COST OF SERVICE

15.0 Reference: Exhibit B-1, Application, Section 3.1.2 F2016 COS Study, p. 3-2
Filing of Annual Fully Allocated COS (FACOS)

On page 3-2, BC Hydro says that it would continue to submit FACOS results with the Commission every year pursuant to 2007 RDA Direction 2. The FACOS would reflect any Commission findings concerning the F2016 COS.

15.1 Please clarify if it is BC Hydro's intention to file FACOS results annually with the Commission pursuant to the methodologies approved in the 2007 RDA, <u>in addition to</u> any newly approved or endorsed methodologies in the 2015 RDA decision.

16.0 Reference: Exhibit B-1, Application, Section 3.1 Cost of Service, pp. 3-1 and 3-2
Lieutenant Governor in Council rate rebalancing amendment

BC Hydro identifies on page 3-1 that: "…rate design is informed by a comparison of energy, demand and customer-related costs, as identified in the F2016 COS study, and revenue from energy, demand and basic charges."

BC Hydro further states on page 3-2 that: "The F2019 COS would be the subject of stakeholder engagement prior to filing and would include a rate rebalancing proposal if appropriate. BC Hydro would continue to submit Fully Allocated COS results with the Commission every year pursuant to 2007 RDA Direction 2."

16.1 Since the Commission cannot use this COS review for the purpose of changing the revenue-to-cost (R/C) ratios, and since the proposed shifts in basic charges and demand cost revenue collection are well below the allocated costs, is there much purpose in undertaking a detailed evaluation of the 2016 COS Study (COSS)? Please discuss.

16.1.1 BC Hydro is proposing to continue to submit its annual Fully Allocated COS results in the intervening years before a full COSS in F2019. What is BC Hydro's expectation in how the Commission would use the information filed?

17.0 Reference: Exhibit B-1, Application, Section 3.5.2, Cost of Service, p. 3-10, Table 3-1 & Table 3-6
2007 RDA COS methodology

17.1 Please provide a revised Table 3-6 in which the right-hand column is calculated using the same data as was used for the final F2016 COS study. Are the differences in the R/C ratios an indication of the legitimate differences in assumptions as they impact the accuracy of the final R/C findings?

18.0 Reference: Exhibit B-1 Application, Section 3.5.4, pp. 3-12 and 3-13
Load data

On pages 3-12 and 3-13, BC Hydro discusses the increased accuracy of the load research data and customer load profiles due to SMI.

18.1 Please identify and quantify the benefits, if any, which are created by the increased accuracy of the load data or a reduction in the costs of acquiring the data.

18.2 Are any such benefits included in the allocation of Smart Meter Infrastructure (SMI) costs? If so, how, and if not, should they be?

BC Hydro refers to the availability of SMI information for analysis that "can be done" and "would yield" much greater accuracy.

18.3 Please confirm that the detailed SMI information was used as described on pages 3-12 and 3-13 in the development of residential load profiles and demand usage. If not, why not?

19.0 Reference: Exhibit B-1 Application, Section 3.6.3, p. 3-14
Functionalization of Generation

BC Hydro says that subsidiary net income, which is primarily derived from Powerex, is assigned to the Generation function on the basis that the income is associated with energy sales.

19.1 Presumably, Powerex energy sales require delivery on the BC Hydro transmission system to an Interconnection with a neighbouring system. Please confirm that none of the subsidiary net income is assigned to the Transmission function, and the reason for that is because any transmission-related revenues in the gross income are offset by charges for transmission under the OATT and any other transmission charges on neighbouring systems. If that is not the case, please explain.

20.0 Reference: Exhibit B-1 Application, Section 3.6.3, p. 3-14
Sub-functionalization of Distribution

BC Hydro states that it has sub-functionalized the Distribution system into: substations, primary system, transformers, secondary/services and meters, based on the advice of the COS consultants and the Commission's comment in the 2007 RDA.

20.1 Please provide a reference in the COS model where this sub-functionalization is shown.

21.0 Reference: Exhibit B-1 Application, Section 3.6.5, pp. 3-15 to 3-17;
Appendix C-2A, Cost of Service Methodology Review (leidos report), p. 4-7; and
Appendix C-2B, Workshop 4 Consideration Memo, p. 31, Table 8
Functionalization procedure

BC Hydro says that it functionalizes O&M costs using Schedules 5.0 to 5.4 of the F2015-F2016 RRA Financial model, which map business groups to different functional areas. If a business group provides services to multiple functional areas (e.g. Environmental Risk Management or Aboriginal Relations), the RRA maps it according to the functional area that captures a majority of the costs incurred.

BC Hydro also says that it considered using bottom-up methods to estimate the proportion of work that spans multiple functional areas, but observed that it would be administratively complex without a corresponding gain in accuracy. On pages 3-16 and 3-17, BC Hydro sets out four reasons for choosing to functionalize business group costs entirely to the predominant functional areas.

Reason 1 on page 3-16 states that with the exception of IT costs, the total dollars from business groups that span multiple functional areas are relatively small, representing less than one percent of the F2016 revenue requirement. Reason 2 states that the difference between splitting the costs among multiple functional areas versus functionalizing to a primary group has a negligible impact on R/C ratios.

The leidos report says on page 4-7 that:

> One general observation we made from our review of the BC Hydro COS model is that BC Hydro utilized a more limited sub-functionalization of its revenue requirement compared with the levels being used by other utilities of similar size and complexity. Significantly greater detailed information for both costs and operational aspects of the utility may be available to BC Hydro, and this more detailed information may add value if incorporated into the COS methodology.

21.1 Is BC Hydro's decision not to use "bottom up" methods essentially a decision to reject the observation of the leidos report that BC Hydro might benefit from a higher degree of sub-functionalization? Please explain.

21.1.1 Table 8 on page 31 of the Workshop 4 Consideration Memo indicates that BC Hydro has diverged from Direction 4 of the 2007 RDA Decision, and has sub-functionalized the distribution system. Is this an instance where BC Hydro has adopted the observation of the leidos report? If so, has BC Hydro adopted the leidos recommendation to increase the degree of sub-functionalization anywhere else in the F2016 COS study?

21.2 Please provide an approximate estimate of the accuracy of the R/C ratios derived from the business group mapping method that BC Hydro has used (e.g. +0.1 to -0.05).

21.3 Please provide an approximate estimate of the accuracy of the R/C ratios that would be created if a "bottom up" or sub-functionalization approach was broadly used (e.g. in areas such as customer care costs).

22.0 Reference: Exhibit B-1 Application, Section 3.6.5, pp. 3-15 and 3-16
Functionalization of Aboriginal Relations costs

BC Hydro says that the operating costs of its Aboriginal Relations group are functionalized entirely to T&D even though some of the operating cost is likely Generation related.

22.1 Schedule 5.4 of the F2015–F2016 RRA Financial model shows Aboriginal Relations operating costs of $5.1 million under T&D and $0 in Schedule 5.2 under generation. However, Schedule 1.0: Functionalization Details of the COS model appears to show that, out of a total of approximately $43 million of OM&A related to First Nations, about $19 million was functionalized to Generation and $24 million to Transmission. Please explain these differences.

23.0 Reference: Exhibit B-1 Application, Section 3.6.6, pp. 3-19 and 3-20; Appendix C-2B, Workshop 4 Consideration Memo, p. 7; and Appendix C-2A, Cost of Service Methodology Review (leidos report), p. 4-6
Demand-side management

BC Hydro has proposed to functionalize DSM as 90 percent generation, 5 percent transmission and 5 percent distribution, but notes on page 7 of the Workshop 4 Consideration Memo (in Appendix C-2B) that "…allocation of the final 10 per cent wholly to Generation, wholly to Transmission, or as between Transmission and Distribution, will not materially impact the allocation of cost to rate classes."

The Cost of Service Methodology Review (leidos report) on page 4-6, recommends that "…BC Hydro consider functionalizing DSM costs based on the relative proportions of BC Hydro's generation plant in service to transmission plant in service. As such, the functionalization approach would be consistent with the classification approaches."

23.1 If BC Hydro adopted the approach recommended by the leidos report, what would be the functionalization percentages of DSM costs?

23.2 Please discuss why BC Hydro has rejected the approach recommended by leidos in favour of its proposed functionalization of DSM costs.

24.0 Reference: Exhibit B-1, Application, Chapter 3 Cost of Service, pp. 3-20 – 3-21; Appendix C-2B, Workshop 4 Discussion Guide, p. 5
Functionalization of regulatory accounts

In Appendix C2-B (p. 64 of 205), BC Hydro states:

> Deferral accounts have historically been functionalized as 100% Generation and classified as 42% energy and 58% demand, which is the classification for the aggregate Generation costs using a plant-in-service ratio. Going forward, BC Hydro proposes to align Deferral account classification with total Cost of Energy which has a split of about 90% energy and 10% demand.
>
> Regulatory accounts have historically been lumped together with Deferral accounts but not all of these accounts should be functionalized as Generation."

24.1 Please explain and clarify the difference between Regulatory accounts and Deferral accounts. What are the properties and cost drivers of each type?

BC Hydro explains that the Rate Smoothing regulatory account, an amount of $122.4 million in the F2016 RRA, was previously assigned to each function proportionate with functionalized O&M.

24.2 Please explain the rationale behind the previous functionalization to O&M. Are all of the accruals into the Rate Smoothing regulatory account necessarily all related to O&M costs? If not, please explain whether amounts related to costs other than O&M are material, and if so, what they are related to.

24.3 Aside from the Rate Smoothing regulatory account, what other regulatory accounts exist with BC Hydro that also have large balances? How are these regulatory accounts proposed to be treated in terms of functionalization and why?

24.4 Please summarize the rationale for the COS Consultant's recommendation that the Rate Smoothing regulatory account now be functionalized as proportionate to the functionalization of the total revenue requirement. Please provide a reference in the COS Consultant's report to the recommendation.

24.5 Given that Regulatory accounts have historically been lumped together with Deferral accounts which have been functionalized as 100 percent Generation, please explain the first line of Table 3-3, which shows that the "previous O&M method." This line item indicates that the Rate Smoothing regulatory account was previously functionalized to each category of Generation, Transmission, Distribution and Customer Care. Please clarify.

24.6 In Table 3-3, using the COS Consultant's recommended method increases the functionalization to Generation, while reducing the functionalization to Transmission, Distribution and Customer Care. Which customer classes will most likely be impacted by the higher proportional functionalization to Generation costs? Please discuss.

25.0 Reference: Exhibit B-1 Application, Sections 3.7.1 and 3.7.3, pp. 3-23 to 3-26; Appendix C-2A; Cost of Service Methodology Review (leidos report), and Workshop 2 Discussion Paper; Appendix C-2B, Workshop 4 Discussion Guide, pp. 5 to 7; and Workshop 4 Consideration Memo, pp. 9–12
Classification of Heritage hydro generation

On page 8 of the Workshop 2 Discussion Paper/Strawman Proposal (in Appendix C-2A), BC Hydro says in Table 2, in the 'Cons' for Option 1, that Option 1 "…implies that IPPs, net imports and hydroelectric generation should be treated with a load factor approach because all these sources serve load. If confirmed, this may overestimate the demand contribution of these resources."

Footnote 137 on page 3-24 of the Application states: "Given that BC Hydro proposes to classify IPPs separately from Heritage hydroelectric…it is appropriate to adjust the load factor calculation to remove the impact of IPPs serving load. System load factor is calculated based on loads almost entirely served by Heritage hydroelectric supply."

Page 3-26 of the Application states that BC Hydro's preferred IPP classification is the "Value of Capacity" option, which results in a 93 percent energy and 7 percent demand classification.

25.1 With respect to the statement that: "…it is appropriate to adjust the load factor calculation to remove the impact of IPPs serving load," please describe more precisely how the load factor calculation is adjusted to remove the impact of IPPs.

25.1.1 Similarly, for the related remark that system load factor is calculated based on loads almost entirely served by Heritage hydroelectric supply, please explain how the load factor is calculated to exclude load that is not served by Heritage hydroelectric supply.

25.2 Does the adoption of a Value of Capacity option reduce or eliminate the concern raised in Table 2 of the Workshop 2 Discussion Paper (page 8) that a load factor approach to classifying IPPs could result in an overestimate of the demand contribution of these resources? If so, to what extent?

25.3 Bullet 2 on page 6 of the Workshop 4 Discussion Guide (Appendix C-2B) states that the capacity factor calculation can be variable year over year because of the addition of hydroelectric

generating capacity. Completion of Mica Units 5 and 6 in F2016 increases generation capacity by more than 800 MW and decreases the system capacity factor.

25.3.1 Is this also a factor in favour of the plant capacity approach, to the extent that the plant capacity factor approach recognizes specific expenditures incurred in order to meet peak load, whereas the load factor approach does not? Why or why not?

The last bullet on page 3-23 of the Application describes the plant capacity factor approach as: "A plant capacity factor approach (i.e., ratio of average plant load to nameplate plant capacity) that sub-functionalizes hydro generating facilities in service and O&M costs by individual plant or groups of plants and then uses corresponding plant capacity factors to classify hydro plant and O&M costs, excluding water costs."

25.4 Using the example given in bullet 2 on page 6 of the Workshop 4 Discussion Guide (Appendix C-2B) that completion of Mica Units 5 and 6 in F2016 increases generation capacity by more than 800 MW and decreases the system capacity factor, please describe in more detail how the completion of Mica Units 5 and 6 would decrease the system capacity factor.

Bullet 4 on page 6 of the Workshop 4 Discussion Guide says that the load factor approach has jurisdictional support (e.g, Newfoundland Power, Idaho Power, Avista).

On pages 4-1 to 4-3 of its report, leidos uses the results of its jurisdictional review to support its recommendation that BC Hydro consider using either a system load factor approach or a plant capacity factor approach to classify hydro costs, excluding water rental costs. Table C-1 in Appendix C of the leidos report confirms the use of the system load factor method by Newfoundland Power, Idaho Power and Avista-Washington.

25.5 It is not evident that any of the surveyed utilities shown in Table C-1 use a plant capacity approach, unless the Peak Credit method is essentially similar to the plant capacity approach. Is the Peak Credit method fundamentally the same as the plant capacity approach? If not, what is the jurisdictional support for the recommendation that BC Hydro consider the plant capacity approach?

25.6 Did leidos, in its jurisdictional review, also review the decisions of the relevant regulatory bodies with regard to their reasons for accepting or rejecting either the system load factor approach or the plant capacity factor approach? If they did, or if BC Hydro has separately reviewed them, please summarize the relevant findings and provide citations (or links) to the original decisions.

25.7 In footnote 3 to Table C-1, leidos says that Avista Corporation – Idaho indicated that a system load factor approach to classification would be preferable, but to potentially limit the number of issues in their case, Avista used the prior Peak Credit method in the cost of service study. Can leidos provide the reasons why Avista – Idaho would prefer a system load factor approach?

26.0 Reference: Exhibit B-1 Application, Appendix C-2B Workshop 4 Discussion Guide, p. 9 Classification of Heritage Thermal Generation

On page 9 of the Workshop 4 Discussion Guide (Appendix C-2B), BC Hydro proposes to classify the Burrard Thermal Generating Station's O&M and capital costs as 100 percent demand, and its associated fuel costs as 100 percent energy.

26.1 Since BC Hydro cannot rely on Burrard for firm energy and will continue to use Burrard for voltage support, would it be more consistent to treat all of Burrard's costs, including fuel, as 100 percent demand? Why or why not?

26.1.1 What would be the impact on R/C ratios of the treating all Burrard costs as 100 percent demand?

27.0 Reference: Exhibit B-1 Application, Sections 3.7.3, p. 3-26; Appendix C-2A; Workshop 2 Discussion Paper, Attachment 4 and COS Methodology Review Presentation, slide 43; and Appendix C-2B, Workshop 4 Consideration Memo, p. 8
Classification of Generation – independent power producers

Page 3-26 of the Application states that BC Hydro's preferred IPP classification is the Value of Capacity option, which results in a 93 percent energy and 7 percent demand classification.

Attachment 4 to the Workshop 2 Consideration Memo (Appendix C-2a) notes on page 1 that as of April 1, 2014, BC Hydro had 86 Electricity Purchase Agreements (EPAs) with in-service IPP projects and a further 41 for under-development IPP projects. Attachment 4 provides contract information for 4 EPAs with fixed cost components and discusses the energy and capacity contributions of the 4 EPAs. It says that classifying EPA purchases on the basis of the fixed and variable components would produce counter intuitive results.

Slide 43 of the COS Methodology Review Presentation (Appendix C-2A) shows the percent classified as demand for IPPs using the Value of Capacity method.

On page 8 of the Workshop 4 Consideration Memo BC Hydro agrees that its preferred Option 2 ('Value of Capacity') for classifying IPP costs is based on the 2013 IRP's Long-Run Marginal Cost for energy (upper end of $100/MWh) and for Generation-related capacity ($55/kW-year) in $2013.

27.1 Please provide a table or calculation that shows the Value of Capacity derivation of the IPP classification of 93 percent energy and 7 percent demand for IPP contracts.

28.0 Reference: Exhibit B-1 Application, Section 3.7.4, pp. 3-26 and 3-27
Classification of Generation-related DSM

BC Hydro states that its rationale for functionalizing 90 percent of DSM to Generation is that "…DSM expenditures are primarily incurred to avoid generation-related costs, which also avoids the classification of those same costs into energy and demand. Therefore, to be consistent with the rationale for functionalizing DSM costs to generation, BC Hydro believes that the classification of Generation-related DSM costs should mirror the classification of overall Generation costs in the revenue requirement."

28.1 Does this mean that it mirrors the classification of Heritage hydro Generation-related costs, which make up the bulk of the costs, or that it reflects a weighted average of all Generation-related costs, including thermal and IPPs, or something different than either of those alternatives? Please explain, including references to the sheets in the COS model where the treatment of Generation DSM related costs is shown.

29.0 Reference: Exhibit B-1 Application, Section 3.7.7, pp. 3-27 to 3-29; and Appendix C-2B, Workshop 4 Discussion Guide, p. 2 Table 1, and pp. 13-14; and Appendix C-2A; Cost of Service Methodology Review (leidos report), pp. 4-4 to 4-6
Classification of Distribution Costs

BC Hydro says on page 3-28 of the Application that: "Generally there are three approaches to classifying distribution costs: (1) minimum system; (2) zero-intercept; and (3) the use of professional judgment to separate demand-related and customer-related distribution costs." BC Hydro further notes that the COS consultants recommended approach (3). On page 3-29, BC Hydro says that it proposes to classify Distribution costs based on Table 1 of the Workshop 4 Discussion Guide (in Appendix C-2B), which appears to be based on the adoption of approach (3). Table 1 of the Workshop 4 Discussion Guide separates and classifies distribution cost categories under the Preferred Option and an Alternative for Sensitivity analysis.

29.1 The cell in Table 1 showing the Alternative for Sensitivity Analysis for distribution indicates a 100 percent demand classification for secondary/services and a 100 percent customer classification for services. Is it correct to assume that this should show a 100 percent demand classification for the secondary portion and a 100 percent customer classification for services?

29.2 If the assumption in the above question is correct, then does BC Hydro accept that the table below accurately reflects the classifications of the Distribution asset categories shown in Table 1 of the Workshop 4 Discussion Guide? If not, please provide a corrected copy of the table.

Asset Category	BC Hydro Preferred Option	Alternative for Sensitivity Analysis
Substations and primary system	100% Demand	100% demand
Transformers	50% demand; 50% customer	100% demand
Secondary/services asset category (split 50% secondary; 50% services)		
• Secondary Portion	100% demand	100% demand
• Service Portion	100% customer	100% customer
Meters	100% customer	100% customer

29.2.1 Is it correct to conclude that the only difference between BC Hydro's Preferred Option and the Alternative for Sensitivity Analysis is in the classification of transformers? If not, why not?

On page 22 of the Workshop 4 Consideration memo (Appendix C-2B), BC Hydro says that the 50 percent demand / 50 percent customer classification should not impact the total costs allocated to each rate class because the direct assignment approach will be used for assigning costs among rate classes.

29.3 It would seem reasonable to conclude that a result of the direct assignment of transformer costs is that the percentage of transformer costs classified as customer or demand will not impact the overall costs assigned to a customer class. However, Table 7 on page 14 of the Workshop 4 Discussion Guide indicates that there is a difference in the R/C ratios under BC Hydro's Preferred Option 1 and Option 2. Please explain.

30.0 Reference: Exhibit B-1 Application, Section 3.8.4, pp. 3-33 to 3-34; Appendix C-2C, Stakeholder Feedback, p. 63 of 79, APMC March 16, 2015 Comments
Allocation of distribution demand-related costs

BC Hydro is using 1NCP (non-coincidental peak) based on average rate class load profiles for five years to assign Distribution demand related costs. The APMC, in its March 16, 2015 comments says that:

> The demand determinants used by BC Hydro are based on a 5-year average, and the energy determinants are based inconsistently on a single year F2016 forecast. Demand and energy allocators should both be determined as a 5-year average of actual recorded data and not based on forecasts, particularly for a single year such as F2016.

30.1 Please confirm that BC Hydro's COS model energy allocator is based on an F2016 energy forecast, and that the Distribution demand allocator is based on average rate class load profiles for 5 years (F2010 to F2014).

30.1.1 If no, please clarify which data are used for the energy and demand allocators.

30.1.2 If yes, would it be preferable, for reasons of consistency and stability of values, to use five year averages for both the energy and demand allocators? Please explain.

31.0 Reference: Exhibit B-1 Application, Section 3.8.4, p. 3-35; Appendix C-2B, Workshop 4 Consideration Memo, p. 24; and Appendix E, 2016 COS Model, Schedules 3.2 and 5.1
Allocation of distribution demand-related costs

In Table 3-5 on page 3-35 of the Application, BC Hydro says that: "Separate NCP allocators are used to allocate distribution demand related costs to primary and secondary distribution customers. The draft model used a single allocator covering all distribution customers."

On page 24 of the Workshop 4 Consideration Memo, BC Hydro says that each rate class is assigned a 1NCP percentage allocator based on its annual peak load as a proportion of the sum of all rate classes annual peak load.

Schedule 3.2 of the COS model (Appendix E) shows that the Distribution Demand Related allocator is NCP; the Distribution Secondary Demand Related allocator is NCP w/o primary. Both of these refer to Schedule 5.1, which has columns for 4 CP, NCP w/o Transmission and NCP w/o Primary.

31.1 Please confirm that the NCP and NCP w/o Transmission are 1NCP allocators. If not, please explain.

Reference to Schedule 5.1 indicates that the NCP allocator for Distribution Demand (in Schedule 3.2) is the same as the NCP w/o Transmission in Schedule 5.1. The allocator for Distribution Secondary Demand

Related is shown in both Schedule 3.2 and 5.1 as NCP w/o Primary.

31.2 Please describe the method of deriving the NCP w/o T and the NCP w/o primary allocators.

32.0 Reference: Exhibit B-1 Application, Section 3.8.5, p. 3-34; Appendix C-2B, Workshop 4 Discussion Guide, pp. 14–16, Figure 1 and Table 7
Allocation of customer care costs

BC Hydro allocates customer care costs using a 90/10 weighted allocator between number of customers and revenue by rate class. The Workshop 4 Discussion Guide (pp. 15–16) compares the Customer Care Weighted Allocator method with a more detailed bottom up analysis. On page 3-34 of the Application, BC Hydro refers to the Workshop 4 Discussion Guide and says that Figure 1 demonstrates that the existing 90 percent/10 percent allocator aligns well with a direct allocation of customer costs.

32.1 Please elaborate on the pros and cons of the weighted allocator versus the bottom up methods of allocating customer costs. In other words, given that the weighted allocator method and the direct allocation method align well with each other, would it be appropriate to adopt the more direct approach (direct allocation)?

33.0 Reference: Exhibit B-1 Application, Appendix C-2A, Distribution COS Study, pp. 9 and 10; Appendix C-2C (page 28), Schedule RRA 3.4, line 10
Substation Distribution Asset (SDA) Allocation

On page 10 of the Distribution COS study (Appendix C-2A), BC Hydro says that: "The SDA function revenue requirement is shown in Table 1 above and is $32.8 million in F2010." Schedule RRA 3.4 of the F2016 COS model shows the largest of the Internal Allocations is the SDA Allocation at $148.3 million. Please describe the reason(s) for the difference between the SDA function F2010 revenue requirement of $32.8 million and the F2016 SDA Internal Allocation of $148.3 million.

33.1 Table 1 on page 9 of the Distribution COS Study shows that the Internal Allocation of SDA Asset charges, has ranged from $25.3 million in F2007 to $32.8 million in F2010. If the reason for the difference between the F2010 SDA amount and the F2016 internal allocation amount is a result of growth in the SDA, please explain the main reason(s) for such high growth from F2010 to F2016 relative to the F2007 to F2010 period.

34.0 Reference: Exhibit B-1, Application, Section 3.9 Revenue to Cost Ratios, p. 3-36 Table 3-6; Workshop 2 Consideration Memo, p. 29
Final Study R/C Ratios Filed in the RDA

In the BC Hydro Consideration of Participant Feedback on the June 19, 2014 Workshop No. 2, BC Hydro says on page 29:

> BC Hydro plans to propose a 95 percent to 105 per cent R/C ratio range of reasonableness as part of its 2015 RDA. BC Hydro expects SMI-related information will further improve confidence in COS results relative to BC Hydro's 2007 RDA proposed R/C ratio range of reasonableness of 90 per cent to 110 per cent.

As a result of BC Regulation 140/2015 deposited on July 15, 2015 (see Exhibit B-1, page 2-7) which ordered that "the Commission must not set rates for the purposes of changing the R/C ratio for a class

of customers," BC Hydro's intended range of reasonableness proposal was not put forward in the 2015 RDA.

Table 3-6 presents the R/C ratios of two different COS study methodologies. It appears that most of the R/C ratios have not changed much from the February 8, 2014 filing based on 2007 RDA Decision except for Residential and SGS.

34.1 Please summarize the factors that led to the large reduction in the SGS R/C ratio and the modest increase in Residential R/C ratio in the current filing.

C. CHAPTER 4 – RATE CLASS DETERMINATION

35.0 Reference: Exhibit B-1, Application, Section 4.3.2.2 Potential Extra Large General Service Class, p. 4-14
Extra large general service (XLGS) Segmentation

On page 4-14, BC Hydro indicates that it commits to undertaking additional engagement with stakeholders who potentially would take service under an LGS Transmission Service Rate (TSR)-like rate, and bringing forward its analysis and proposal as part of RDA Module 2.

35.1 BC Hydro is requesting a flat energy rate as default rate for the LGS class in Module 1. If the flat rate is approved in Module 1, would BC Hydro be requesting the TSR-like rate to be an option for the LGS rate class customers under the default flat rate or would the TSR-rate be only available to a segmented group of XLGS customers as default rate? Please discuss.

36.0 Reference: Exhibit B-1 Application, Section 4.5 Irrigation rate class, p. 4-23
Irrigation

BC Hydro proposes no changes to the existing Irrigation class. The service RS 1401 is available to customers for electricity use during the Irrigation Season, defined as the period between March 1 and October 31.

36.1 Does BC Hydro consider that conservation savings can be targeted from the Irrigation class? Does BC Hydro have information on price sensitivity of irrigation customers? If so, please provide the information. If not, please explain why BC Hydro has not targeted this rate class for conservation savings.

D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

37.0 Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, pp. 5-3 and 5-16; Appendix C-3B, Evaluation of the RIB report
RIB Conservation Savings

The existing RIB rate is BC Hydro's preferred default Residential rate.

BC Hydro states that the 2013 RIB Evaluation report "concluded that the RIB rate appears to be achieving its overall objective of encouraging conservation through Residential customer response..." BC Hydro also states that the RIB is expected to have delivered approximately 480 GWh/year in cumulative

conservation over the first ten years of implementation, which is from October 2008 through F2017 (p. 5-3).

37.1 Is the successful delivery of conservation savings the major reason for BC Hydro's preference? Has adverse bill impacts (compared to flat rate) and economically efficiency rate structures been design issues when BC Hydro was selecting its preferred rate design?

37.2 Please discuss the forecast of cumulative conservation for the first ten years of implementation. If available, please provide the annual forecast between F2009 and F2015, comparing to actual conservation achieved. If annual information is unavailable, provide the cumulative forecast and cumulative savings achieved.

37.3 Can BC Hydro's model be used to determine (ignoring bill impact constraints) the (i) optimum tier 1 / tier 2 spread to maximize conservation, or (ii) the optimum Step 1 threshold to maximize conservation? If yes, please provide the optimum levels. If no, please explain the usefulness of the model in identifying conservation benefits from alternative rate designs.

38.0 Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, p. 5-18
Customer responsiveness, awareness, and understanding

BC Hydro indicates that a total of 50 percent of Residential customers appear to be aware of the RIB rate as of February 2012. During Workshop 9a, BC Hydro responded to a BCSEA inquiry as to whether the 50 percent customer awareness could be increased. BC Hydro indicated that an increase in customer awareness would come at a cost.

38.1 Presumably, customer awareness has increased since the launch of the RIB rate in 2008. Has BC Hydro monitored this increase in awareness over the last number of years? If so, please comment on the results.

38.1.1 For those customers who displayed awareness of the RIB rate, please describe the respective percentage shares (e.g., for F2010 and F2014) of those customers who: (a) experienced lower bill impact than flat rate; (b) who experienced higher bill impact that flat rate; and (c) who experienced neutral impact. Please comment if the awareness is related to positive or negative bill impacts.

38.2 Please comment on whether this 50 percent awareness is reasonable in BC Hydro's view. What is the basis of comparison? Is BC Hydro aware of the results of comparative rates for utilities in other jurisdictions?

39.0 Reference: Exhibit B-1, Application, Section 5.2.4.1 Flat Rate, p. 5-22
Bill Impacts

BC Hydro states that its primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers.

39.1 Assuming that above scenario (i.e., adverse bill impact) took place but it was for a good policy objective such as conservation savings, should the bill impact be analyzed only for the purpose of designing mitigating factors? Should the rate structure design in itself primarily address economic efficiency and rate stability criteria?

40.0 Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, pp. 5-25 to 5-29 Three Step Rate

BC Hydro modelled and assessed three different options for a 3-step rate and only option A was carried forward in the Application. BC Hydro states that it does not anticipate much incremental conservation by adopting the 3-step A option and there would be moderate decreases in customer understanding and acceptance, as compared to the RIB rate.

40.1 In Slide 50 of Workshop 9a presentation materials (Exhibit C-3b), please explain the line labelled "Cumulative conservation vs. SQ." How does this compare to the "incremental conservation" identified in the preamble?

40.2 Please confirm that the "cumulative conservation" identified on Slide 50 is calculated based on the price elasticity of -0.10 for Step 2 or the class average price elasticity of -0.05 for natural conservation.

40.3 Please confirm whether BC Hydro is using the same Step 2 price elasticity of -0.10 to calculate the potential conservation from step 3? Is empirical evidence available to support that consumption at the third tier has higher elasticity than consumption in the lower tiers?

40.4 If only a very small percentage of customers consume at Step 3, does it matter that there is a "moderate decrease in customer understanding and acceptance?"

BC Hydro indicates that only one Canadian jurisdiction, YECL, has a 3-step rate structure.

40.5 Please discuss whether YECL would be a valid comparator at all to BC Hydro, given its geography, percentage of electric heat, size and customer types.

40.6 BC Hydro also indicates that the CPUC had recently reduced the current four step residential rate structure of three large California utilities to 2 steps. To the best of BC Hydro's knowledge, please generally discuss if the 3-step rate achieved the expected conservation savings and the reasons for reducing the multi-tier rate to a 2-tier rate. ?

41.0 Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, p. 5-33 to p.5-35 RIB pricing principles

BC Hydro explains that by applying the RRA increases equally to all 3 rate elements, the step 2 energy rate would exceed the upper range of BC Hydro's LRMC (option 1).

Option 2 is to apply the RRA increase to the Step 1 energy rate and basic charge while holding step 2 energy rate at its current level.

41.1 In the Commission's 2011 RIB Rate Re-pricing decision (page 8 of 19), it was affirmed that the levelized weighted average plant-gate price of BC Hydro's most recent call for energy as a proxy for LRMC. It does not include BC Hydro's capacity costs. Would including capacity costs in the LRMC estimate arguably lend the 2-step rate to be an economically efficient rate?

41.2 For Figure 5-19 please discuss whether economic efficiency may still be achieved given that the Step 2 rate will be higher than LRMC for option 2 (with more differential in F17 and less so by F19).

42.0 Reference: Exhibit B-1, Application, Section 5.2.5.2 Basic Charge; Section 5.2.5.3 Minimum Charge, pp. 5-41 to 5-43
Basic Charge and Minimum Charge

BC Hydro states that the Basic Charge is intended to recover a portion of its customer costs, while minimum charges are intended to recover a minimum contribution towards fixed costs, or some portion of the cost of customers remaining connected to the system during periods of very low consumption or dormancy.

Currently the Basic Charge is the Minimum Charge. It is stated in the Application that $15 a month Minimum Charge is roughly equivalent to the average fixed Distribution and customer-related cost per month per Residential customer. However, BC Hydro is not proposing a minimum charge.

42.1 Please clarify whether BC Hydro, when modelling the $15 per month minimum charge, also considered generation and transmission costs in addition to customer cost and distribution costs?

42.2 What percentage of customer-related costs is recovered through the current basic charge?

42.3 On page 5-42, BC Hydro discusses its jurisdictional assessment of Canadian utilities' residential Basic Charge cost recovery. Does BC Hydro also have a jurisdictional assessment of minimum charges?

42.4 Please provide the F2014 and F2015 data, in tabular format, of Residential customers who paid the Minimum Charge for a) 12 months of the year, b) 9 months of the year, c) 6 months of the year, and d) 3 months of the year.

42.4.1 Please provide the regional breakdown to the F2014 and F2015 data.

43.0 Reference: Exhibit B-1, Application, Section 5.3 Residential Dual Fuel E-Plus Rate, pp. 5-54 to 5-56
E-Plus customers interruption notice

BC Hydro favours amending RS 1105 Special Condition 1 to provide a practical interruptible option. As its business practice, one of the ways of notifying E-plus customers for interruption is "up to one week's notice that an interruption event is likely to occur."

43.1 Please provide an example of an *event* that will allow BC Hydro to provide up to one week's notice to E-Plus customers regarding interruption.

43.2 Please describe the investigation work – planning, execution and outcome – undertaken on residential demand response described on page 5-54.

44.0 Reference: Exhibit B-1, Application, Section 5.4 Low Income rate, p. 5-57 and p. 5-58
Low income rate

BC Hydro states that low income rates are likely to be seen as unduly preferential or unduly discriminatory and divorced from the cost causation principle (p. 5-58). BC Hydro also states that in those jurisdictions where low income rates have been introduced, legislation has been introduced.

44.1 If low income rates were introduced and approved, please discuss how BC Hydro would verify

income data without violation of personal information. Please also discuss any administrative barriers in this regard.

45.0 Reference: Exhibit B-1 Application, Section 5.2.5.1, Table 5-8, pp. 5-34 to 5-37
F2017–F2019 Pricing principles and bill impacts

On page 5-34, BC Hydro provides a table showing the bill impacts under Pricing Principles Option 1. For Option 2, BC Hydro provides a figure for each of the three fiscal years (Figures 5-20 to 5-22) showing the cumulative bill impacts versus annual consumption.

45.1 Please provide similar figures for Option 1.

46.0 Reference: Exhibit B-1, Application, Section 5.5.1 Definition of Low Income Customers, p. 5-63
RIB Rate Report Proceeding – Definition of low income customers

In the Commission's RIB Rate Report proceeding, BCOAPO's submission dated October 16, 2015, states on pages 4 to 5: "…given the high incidence (over 25%) of non-responses, it would be useful if BC Hydro were to examine the basic parameters (e.g. electricity usage, heating type) of the two groups (respondents vs. non-respondents) in order to assess whether the inclusion of these records skews the general characteristics of 'low income' customers."

In the Commission's RIB Rate Report Proceeding, COPE's submission dated October 16, 2015, COPE states on page 5: "Energy or fuel poverty is already a growing issue in Canada and BC but given the ever steepening curve of energy cost increases in the future, its relevance and importance is bound to grow."

46.1 As part of its RIB Rate Report proceeding, please confirm if BC Hydro would assess whether the estimate of the characteristics of the low income population is skewed as per BCOAPO's suggestion? Why or why not?

46.2 Does BC Hydro agree with COPE's assertion in the preamble? Please comment on the relevance of examining energy or fuel poverty in the RIB Rate Proceeding report and the feasibility of doing so.

46.3 Please comment on the usefulness and feasibility of using data from the Ministry of Social Development and Social Innovation, such as crisis grant provision data, or other data, to respond to the three questions from the Minister, which relate to low income customers.

47.0 Reference: Exhibit B-1, Application, Section 5.5.2 Defining Factors Leading to High Energy Use, p. 5-69
RIB Rate Report Proceeding – High energy use

BC Hydro defines "high energy use" to include both energy consumption and peak demand. BC Hydro identifies a) electricity consumption by heating fuel: and b) electricity consumption by housing type within region as the factors driving higher than average annual electricity consumption. BC Hydro rejected number of occupants as a factor because it is correlated with the floor area of the home.

In the Commission's RIB Rate Report proceeding, BCOAPO's Submission dated October 16, 2015, states on page 6 that:

There would appear to be merit in both BC Hydro and FortisBC exploring domestic water heating fuel and the presence of other electric high use end-uses, assuming the data exists in their respective REUS's to do so... given that the Minister's questions focus on customers without access to natural gas and low income customers, both Companies should seek to refine their analysis to specifically look at which factors lead to high energy use for each of these two groups as opposed to the Residential class in general.

47.1 Please confirm if "high energy use" is synonymous with "high electric use" in BC Hydro's definition. In BC Hydro's view, should there be a difference in definition for the purpose of the RIB Rate Report?

47.1.1 If the response to the above question is affirmative, please comment on the feasibility of BC Hydro reporting on high energy (or electricity) use for residential customers without access to natural gas and those with access.

47.2 Please comment on the feasibility and usefulness of responding to the Minister's Question 3 for total household energy-use (i.e. all fuel sources).

47.2.1 What data, listed below, does BC Hydro have to examine total household energy use?

a) Data on number and amount of consumption of non-electric end-uses from the Residential End-Use Survey (REUS)?
b) Estimates of the cross-elasticity of demand between electricity and natural gas prices?
c) Other?

47.2.2 Please comment on the feasibility and usefulness of modelling total energy use from all sources by converting energy use into a common measure (e.g., GJ or kWh) and comparing the cost of total energy consumption between those with and those without access to natural gas. Furthermore, given that natural gas prices are at historically low levels, please provide comment on the usefulness of modelling three comparisons; one with natural gas rates in 2008, another using 2012 rates and another using current 2015 rates. If not useful, please provide any other alternative approaches.

47.2.3 Please comment on the feasibility and usefulness of the Commission requesting BC Hydro's comments in the report on the Minister's questions about the impact of natural gas prices on electricity consumption for those with access to natural gas.

47.3 Please specify if there are additional regions other than Vancouver Island, the North, South Interior and Lower Mainland in the analysis of "housing type within region." Please explain whether or not the regions should be broken down further.

47.4 Please comment on the feasibility of BC Hydro reporting on other "factors" that lead to high energy use such as various end-uses including but limited to water heating fuel, pools, hot tubs, etc.

47.4.1 What specific end-use data does BC Hydro have from its 2012 REUS?

47.4.2 Is BC Hydro amenable to reporting on household occupancy even though it may be correlated to home floor area? If not, why not? If not, please provide evidence of the

correlation between household occupancy and home floor area.

48.0 Reference: Exhibit B-1, Application, Section 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, p. 5-70
RIB Rate Report Proceeding – definition of access to natural gas

BC Hydro proposes adopting a community approach to define access to natural gas.

In the Commission's RIB Rate Report proceeding, BCOAPO's Submission dated October 16, 2015, states on page 12 that: "In our view, an equally valid definition of "access to natural gas" could include residential customers who cannot afford to switch from electricity to natural gas or are unable to switch for other reasons, even if they could connect to natural gas service in their homes."

In the Commission's RIB Rate Report proceeding, BCSEA's Submission dated October 16, 2015, states on page 4 that:

> BCSEA-SCBC recommend that the Commission elaborate the definition of 'with and without access to natural gas' to deal with customers in communities such Revelstoke (which has access to piped propane), and customers who are outside of both the communities listed by FEI as having natural gas service and the communities listed by BC Hydro (and FBC in due course) as not having natural gas service.

48.1 Please comment on the feasibility of adopting the definition of access to natural gas as proposed by BCOAPO. Can this aspect of the access be reported on in any way?

48.2 Please comment on the feasibility of adopting the definition of access to natural gas as proposed by BCSEA.

49.0 Reference: Exhibit B-1, Application, Section 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, p. 5-70
RIB Rate Report Proceeding – cross-subsidy

The Application that "BC Hydro will assess the possibility of the RIB rate causing a 'cross-subsidy between customers with and without access to natural gas service' posed by Minister RIB Report Letter question 1 using cost of service information."

In the Commission's RIB Rate Report proceeding, BCOAPO's Submission dated October 16, 2015, states on page 7 that: "Both companies' COS analyses require detailed load data, including not only customer counts and energy use but also non-coincident peak (NCP) and coincident peak (CP) data for each of the groups being assessed."

In the Commission's RIB Rate Report proceeding, BCOAPO's Submission dated October 16, 2015, states on pages 14 to 15 that:

> BCOAPO assumes that [the Minister] refers to intra-class cross-subsidy. BCOAPO considers it most likely that such cross-subsidy will exist within many residential rate classes… should the Commission determine that the RIB rates do actually cause cross-subsidy between customers with and without access to natural gas, and that the cross-subsidy is significant, BCOAPO wonders what relevance such a finding would have.

In the Commission's RIB Rate Report Proceeding, Mr. Marty's Submission dated October 16, 2015, states on page 2 that: "Question 1 can only be answered by comparing the revenue flows under the Residential Conservation Rate, as currently structured, with a theoretical two-tier pricing system in which each and every resident experiences the same percentage of electricity consumption in Block 2."

49.1 Please confirm that BC Hydro will examine intra-rate class cross-subsidy based on "with" and "without" access to natural gas in its report for the Minister's Question 1, using a cost of service approach, including examining demand and energy costs.

49.1.1 Please comment on the usefulness of BC Hydro including in the report on Question 1 a discussion of intra-class subsidy in general and the usefulness and relevance of any finding on intra-class subsidy from the report.

49.1.2 Please comment on the feasibility and usefulness of the Commission requesting BC Hydro's comments in the report on the Minister's questions about potential cross-subsidy created by the impact of natural gas prices on electricity consumption for those with access to natural gas.

49.2 Please provide BC Hydro's position on BCOAPO's submission on the cost of service analysis required and specifically the use of CP and NCP. Please explain if adequate data regarding NCP and CP is available.

49.3 Please provide comment on Mr. Marty's submission above.

50.0 Reference: Exhibit B-1, Application, Section 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, p. 5-71
RIB Rate Report Proceeding – Minister's Question 3
High energy use and bill impacts

In the Commission's RIB Rate Report proceeding, BCSEA's Submission dated October 16, 2015, BCSEA states on page 6 that:

> BCSEA-SCBC recommend that the Commission clarify or confirm that there are two subject groups in question 3: (a) customers, regardless of income, without access to natural gas, and (b) low income customers without access to natural gas. If confirmed, note that this is different than in question 2, where the subject group is low income customers with and without access to natural gas (i.e. low income customers in all areas of the utility's service territory).

In the Commission's RIB Rate Report Proceeding, Mr. Marty's Submission dated October 16, 2015, states on page 3 that:

> it is essential that FBC incorporate the other major factors affecting the electricity consumption of these two end-uses for which they have data; particularly, outside temperatures, water heating fuel and secondary home heating fuel… FBC should be directed to examine samples of residences that consume around 30,000 kWh/year, 20,000 kWh/year and 10,000 kWh/year and explain, to the fullest extent possible, the differences in electricity consumption among them. In addition to responding to the Minister's Question 3, such analysis could shed light on how much of the differences in electricity use among customers might be due to the level of household energy

efficiency, which is important for addressing Questions 4 and 5.

50.1 Please confirm that BC Hydro will report on the Minister's Question 3 using the two groups as defined by BCSEA and that BC Hydro will report on the factors that lead to high energy use for each of these two groups.

50.2 Please comment on the feasibility or usefulness of reporting on factors such as temperature, water heating fuel and secondary heating fuel as suggested by Mr. Marty. Does BC Hydro have these data?

50.3 Please comment on the feasibility and usefulness of BC Hydro examining sample residences that consume 30,000 kWh/year, 20,000 kWh/year and 10,000 kWh/year.

50.3.1 Will BC Hydro be able to make any general observations about residences with the consumption levels suggested by Mr. Marty? If not, why not?

50.3.2 Please comment where the analysis suggested by Mr. Marty could shed light on how much of the differences in electricity use among customers might be due to the level of household energy efficiency.

50.4 Please confirm whether BC Hydro will provide actual numbers of low income customers that would be worse off under a flat rate, in addition to percentages.

51.0 Reference: Exhibit B-1, Application, Section 5.6 BC Hydro Residential Demand Side Management Programs, pp. 5-72-78
RIB Rate Report Proceeding – Minister's Questions 4 and 5
Demand-side management programs

In the Commission's RIB Rate Report proceeding, FortisBC Inc.'s submission dated September 30, 2015, states on page 5:

> The Company proposes to provide a list and brief description of existing programs that customers can participate in that can impact the factors identified in response to question 3 above that lead to high energy use…The Company will provide a discussion of any potential additional DSM programs, or potential modifications to existing programs, that could be undertaken within the existing regulatory environment.

In the Commission's RIB Rate Report Proceeding, BCSEA's submission dated October 16, 2015, states on page 6: "BCSEA-SCBC recommend that the Commission clarify that the core of question 4 is what is the potential for existing DSM programs to reduce electricity usage and hence customer bills. For example, what is the potential for an existing DSM program to be ramped up, say with higher incentives, in order to achieve increased energy savings?"

In the Commission's RIB Rate Report Proceeding, Mr. Marty's Submission dated October 16, 2015, states on page 3:

> The potential for FBC's existing DSM programs to mitigate the electricity bill impacts of the RCR depends on two factors:
>
> - energy inefficiency must account for a significant portion of the household's

higher electricity consumption; and

- the household must be contemplating a renovation or replacement of aging energy-using equipment (such as the hot water heater or space heating system).

In the Commission's RIB Rate Report Proceeding, BCOAPO Submission dated October 16, 2015, states on page 13: "…it would be helpful for the companies to comment on whether DSM measures that they each propose would run contrary to the prescribed fuel switching guidelines."

51.1 Please confirm that BC Hydro will report on the Minister's Questions 4 and 5 as FortisBC Inc. has proposed.

51.2 Please comment on BCSEA's recommendation above.

51.3 Please confirm whether BC Hydro will report on the Minister's Question 4 using the two groups proposed by BCSEA: "(a) customers, regardless of income, without access to natural gas, and (b) low income customers without access to natural gas."

51.4 Please comment on the feasibility and usefulness of an analysis of the two factors suggested by Mr. Marty.

51.5 Please comment on the feasibility and usefulness of BC Hydro indicating which of its existing or potential DSM programs could result in fuel switching from electricity to natural gas.

51.6 Please comment on the feasibility and usefulness of the Commission requesting BC Hydro to identify in its report on the Minister's questions any population(s) that have no access to natural gas, high electricity use and a) no access to DSM programs; and b) no access to DSM programs, and are low income.

E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

52.0 Reference: Exhibit B-1, Application, Section 6.1 General Service, p. 6-3
RS 1278

BC Hydro proposes no change to RS 1278. This rate was not reviewed in the 2015 RDA stakeholder engagement process and therefore specific engagement with the customer did not occur. Accordingly, BC Hydro believes it would be inappropriate to eliminate RS 1278 at this time.

52.1 This rate has only one customer and has been closed since the 1970s. Please explain whether BC Hydro would discuss its elimination in module two?

52.2 Is electricity sold to this customer below allocated cost? If so, what rate design principles are achieved by continuing at this rate?

53.0 Reference: Exhibit B-1, Application, Section 6.2.3.1 SGS Rate Structure, pp. 6-8, 6-10
SGS's flat energy rate

The flat energy rate of 11.01 cents/kWh (F2017) as proposed by BC Hydro is within BC Hydro's energy LRMC range (upper bound is 11.13 cents/kWh for F2017).

BC Hydro is proposing a one-time increase to the RS 13xx basic charge to 45 percent recovery of customer-related costs attributable to the SGS class in the F2016 study, and a one-time offsetting reduction of the energy rate in order to maintain revenue neutrality.

53.1 On page 22 of the Consideration Memo in Tab Workshop 11(a)/11(b) in Appendix C4, BC Hydro states that the SGS and RIB basic charges do not recover any demand-related costs. Demand-related costs are recovered through the respective SGS flat energy rate and RIB rate Step 1 and Step 2 energy rates. Approximately what percentage of the proposed flat energy rate of 11.01 cents/kWh is demand cost recovery?

53.2 BC Hydro is proposing an increase of basic charge for SGS customers to 45 percent recovery of customer-related costs. This recovery percentage is similar to the RIB basic charge recovery (see page 5-41). Approximately what percentage of the proposed energy rates of RIB step 1 and step 2 is demand cost recovery?

53.3 If the Commission were to consider including a capacity value to the LRMC as more appropriate, does BC Hydro agree that the proposed recovery of customer-related costs be reduced to a lower level so that the flat rate can be increased to be closer to the LRMC?

54.0 Reference: Exhibit B-1, Application, Sections 6.2.3.2, 6.2.4 & Workshop 11A, Slide 25 Small General Service, p. 6-12 & Slide 25
Small General Service Basic Charge

BC Hydro proposes to increase the SGS basic charge

> … from about 33 per cent to a level comparable to the RIB rate basic charge customer-related cost recovery of about 45 per cent (F2016 COS). As set out in Table 3-7 in Chapter 3, Residential and SGS customer cost allocation is similar, as are energy and demand cost allocations. BC Hydro concluded that the RIB rate basic charge customer-related cost recovery level is the appropriate reference.

BC Hydro also states that only COPE 378 does not support an increase to the SGS basic charge cost recovery since it is directionally counter to energy conservation.

54.1 How will the proposed basic charges for SGS compare to the proposed basic charges for LGS and MGS customers in terms of customer cost allocation?

55.0 Reference: Exhibit B-1, Application, Sections 6.2.4 Small General Service, Table 6-3
Small General Service bill impacts

Table 6-3 shows that the bill impacts from the increase in basic charge is minimal for most customers, although the impact on the smallest customer and the lowest 10 percent of customers exceed BC Hydro's 10 percent bill impact amber signal.

55.1 How many customers are impacted in the lowest 10 percent group of customers? Is there anything BC Hydro would propose to minimize the bill impact on these customers?

56.0 Reference: Exhibit B-1, Application, Sections 6.3.2.1, 6.3.3.2 & Appendix C-4A Medium General Service, pp. 6-17, 6-22 & C-4 A, pp. 8 and 9
Medium General Service Conservation

BC Hydro states on page 6-17: "The two-part energy rate structure was approved for the MGS class under the terms of the NSA. The overarching objective of the two-part rate structure was to provide MGS customers with an efficient price signal to induce energy conservation." Slides from Workshop 8A and 8B identify that the development of the baseline rates for LGS and MGS was a result of Direction 19 of the 2007 RDA directing the development of a LGS rate that encouraged conservation while not harming or benefiting customers unduly.

Page 6-22 states that

> The evaluation of these multiple lines of evidence indicated that the customer response to the MGS two-part energy rate was considerably less than forecast. Awareness and demonstrated understanding of the MGS rates was low. Evaluated net energy savings for MGS rate were not statistically different than zero in 2011, 2012 and F2014, relative to calendar year 2010, as compared to a forecast conservation savings of about 140 GWh/year.

56.1 Does BC Hydro consider that the twin-goal to achieve both conservation and not harming or benefiting customers is inherently incompatible?

56.1.1 Is it fair to conclude that BC Hydro has determined that there is no conservation rate alternative that would be fair to the diverse customer base of the MGS class? Please discuss. In the discussion, please comment whether the conservation shortfall is the result of rate complexity, customer heterogeneity, and low elasticity of demand to rate signals, e.g., factors such as tax deductibility of electricity charges for commercial customers or the relatively low cost of electricity as a business cost to MGS customers as reflected in the low elasticity?

57.0 Reference: Exhibit B-1, Application, Section 6.3.2 Medium General Service, pp. 6-19 and 6-34; Section 6.4.5 Large General Service Rate Structure, pp. 6-55 to 6-56
Medium and Large General Service demand charges

BC Hydro states on page 6-19: "Most jurisdictions have flat or declining demand charges. The key issue associated with the existing MGS three-step inclining block demand charge is that it does not align with BC Hydro's cost to serve MGS customer peak demand, which is generally flat on a $/kW basis."

AMPC commented at Workshop 8b that a flat demand charge would better reflect cost causation.

57.1 Please provide the reference to the COSS demonstrating the demand cost causality being generally flat on a $/KW basis?

57.2 Is this true for all classes of customers?

57.3 Please explain why BC Hydro no longer proposes a first tier demand charge (i.e, 35 kW at zero cost) for MGS and LGS customers. Please comment if retaining this first tier would smooth customers' transition between SGS and MGS rates.

58.0 Reference: Exhibit B-1, Application, Section 6.3.3.2 Medium General Service, p. 6-22, Footnote 237
Medium General Service demand charges

"The MGS forecasted conservation savings were based on the overall commercial customer price elasticity of -0.1 (consisting of rate structure induced conservation and natural conservation) based on the jurisdictional assessment set out in Appendix E to the BC Hydro's 2008 Long-Term Acquisition Plan, with adjustments."

58.1 On page 6-22, BC Hydro states that "evaluated net energy savings for MGS rate were not statistically different than zero in 2011, 2012 and F2014, relative to calendar year 2010, as compared to a forecast conservation savings of about 140 GWh/ year." What level of DSM conservation is expected from the proposed new MGS rate structure and what levels of price elasticity are now assumed for each of the general service classes?

59.0 Reference: Exhibit B-1, Application, Section 6.3.4.2 MGS Screening of Alternatives and Stakeholders Engagement, pp. 6-28 and 6-29
Methodology to estimate energy and peak demand savings

On page 6-28, BC Hydro says: "…. AMPC stated that the inability to annually adjust baselines to reflect changes in use is a significant problem for a heterogeneous class, and thus a flat energy rate may be more useful in providing a conservation price signal than a tiered energy rate."

59.1 In BC Hydro's view, does the above concern hold only for a heterogeneous general service rate class? For example, does the statement also apply to customers taking service at transmission voltage or to Residential customers? Please explain.

59.2 Please elaborate on how a flat energy rate may be more useful in providing a conservation price signal than a tiered energy rate. For example, should the flat energy charge be always set within the LRMC range? Should basic charge and demand charge be lowered in order to allow a higher energy charge within the constraints of revenue neutrality in rate design?

The Application states on page 6-29 that "15 of the 22 feedback forms submitted by attendees favoured the MS-5 MGS flat energy rate alternative with many emphasizing DSM programs as the better vehicle for conservation; three preferred the MS-2 flatten the energy charges but retain the baseline alternative; and two favoured the existing MGS rate."

59.3 Please provide in your response the following data related to MGS customer annual consumption profile:

a. Percentage of MGS customers consuming energy for 12 consecutive months in Part 1 only.
b. Percentage of MGS customers consuming energy for 12 consecutive months at Part 1 and Part 2 rates.
c. Percentage of Part 1 only MGS customers consuming at Tier 2 only for at least 12 consecutive months.
d. Percentage of Part 1 only MGS customers consuming at both Tier 1 and Tier 2 for at least 12 consecutive months.
e. Percentage of MGS customers who trigger the Price Limit Band provision.

60.0 Reference: Exhibit B-1, Application, Section 6.3.4.2 Medium General Service, pp. 6-30 and 6-32 Medium General Service demand charges

BC Hydro reviewed two demand charge related items in the workshop. One item is as follows:

> An increase in demand charge recovery of demand-related costs from 15 per cent to 35 per cent. The 35 per cent cost recovery level was arrived at by targeting an increase that would result in a flat energy rate that remained generally reflective of the energy LRMC, thereby balancing the competing Bonbright economic efficiency criterion. There is no single 'correct' level of demand charge cost recovery and demand charge cost recovery cannot be targeted in isolation from other factors. The effect of an increase to 35 per cent cost recovery is to more evenly offset and distribute the bill impacts of BC Hydro's preferred MGS flat energy rate and MGS flat demand charge among customers with differing load factors and consumption levels.

On page 6-32, the Application comments that "BC Hydro acknowledged that as a result of the proposed increase to the demand charge, the MGS flat energy rate under its proposal drops below the lower bound of the energy LRMC range (F2017: MGS flat energy rate is 8.54 cents/kWh and the lower end of the energy LRMC range is 9.46 cents/kWh)."

In its Workshop 11a/11b consideration memo, BC Hydro adopted the perspective of AMPC that the energy LRMC should not be relied on with a "false precision." BC Hydro regards the MGS flat energy rate under its proposed demand charge cost recovery increase to be reflective of the energy LRMC.

60.1 Would it not have been preferable to have proposed a demand cost recovery percentage that would have kept the flat energy rate closer to LRMC? Please discuss the trade off between customer bill impacts and LRMC price signals.

60.2 What would the energy rate be in Table 6-9 if the flat demand cost recovery were set at 20 percent, 25 percent or 30 percent?

60.3 Under the conservative rate structure, the Step 2 or upper tier rate was designed to have the energy LRMC as referent. In BC Hydro's view, is it still necessary for a flat rate (as proposed for the MGS rate class) to be reflective of the LRMC given that some MGS customers may always be consuming at the current Part 1 level of the 2-part rate?

60.4 When the upper tier of a two-tier rate structure exceeds the LRMC, it may be considered that the pricing is not economically efficient. Does the false precision perspective, advanced by AMPC and adopted by BC Hydro, apply to proposed rates above the LRMC range, i.e., concluding rates are economically inefficient when rates are above LRMC?

60.5 Please confirm that the introduction of LRMC as a range in the 2015 RDA is an admission that the LRMC is not a precise number.

61.0 Reference: Exhibit B-1, Application, Section 6.3.5 BC Hydro Proposal and Stakeholders Engagement, p. 6-33
Illustrative simulation

On page 6-33, BC Hydro describes that all alternatives recover the same target revenue of $371 million given a consumption forecast of 3,517 GWh and 10.9 GW of billed demand.

61.1 The 3,517 GWh consumption forecast is modelled to the status quo MGS rate. Has BC Hydro also modelled forecasts on the energy consumption by MGS customers on the assumption that its proposed default MGS rate design is approved for F17, F18 and F19? If so, please describe the difference in consumption forecast as a result of substantially different price signals.

61.2 In BC Hydro's view, should its stakeholders and the Commission be concerned with increased energy consumption as a result of the MGS rate design changes? Has BC Hydro addressed the conservation savings target that is part of the provincial government's energy objectives? If not, please explain why not.

62.0 Reference: Exhibit B-1, Application, Section 6.3.5 BC Hydro Proposal and Stakeholders Engagement, p. 6-36, Figure 6-6
Bill impact under the demand charge 35 percent Recovery

Figure 6-6 shows that customers experiencing the highest bill impact are characterized by low consumption and low load factor, with impacts mostly triggered by having demand charges for all kW.

62.1 Has BC Hydro conducted an analysis of the likelihood of those MGS customers who are unfavourably impacted as candidates for migration to the SGS rate class? Please describe the analysis.

62.2 In the past three years, what were the migration patterns between SGS and MGS? What were the bill impacts under the status quo tariffs for those who migrated?

BC Hydro shows the bill impacts at both a 35 percent demand cost recovery and at 15 percent.

62.3 Would it be the case that more than 90 percent of customers would have a bill impact less than 10 percent under any of the demand cost recovery proposals between the existing 15 percent and the proposed 35 percent?

63.0 Reference: Exhibit B-1, Application, Section 6.3.5.2 MGS Demand Sensitivity Rate Structure (15 Per Cent Recovery), pp. 6-37, 6-57
Bill impact analysis

On pages 6-37 and 6-56, BC Hydro describes AMPC's belief that high load factor customers make more efficient use of BC Hydro's system and, therefore, the demand sensitivity outcome is not acceptable.

63.1 In BC Hydro's view, is intra-rate class cross subsidy an issue in rate design? Is undue discrimination more specifically applied to inter-class bill impact?

63.2 In making the choice between 35 percent demand recovery and 15 percent demand recovery, what priority or weight should be given to issues related to rate stability (e.g., paying for the first 35 kW which used to be free), price signal (e.g., energy rate below LRMC range) and intra-class cross subsidy? Please explain.

64.0 Reference: Exhibit B-1, Application, Section 6.4.2 Existing LGS Energy Rate, p. 6-40
LGS customer profile

Table 6-14 sets out the existing LGS Energy Rate for F2016.

64.1 Please provide the following data related to LGS customer annual consumption profile:

a. Percentage of LGS customers consuming energy for 12 consecutive months in Part 1 only.
b. Percentage of LGS customers consuming energy for 12 consecutive months at Part 1 and Part 2 rates.
c. Percentage of Part 1 only LGS customers consuming at Tier 1 only for at least 12 consecutive months.
d. Percentage of Part 1 only LGS customers consuming at both Tier 1 and Tier 2 for at least 12 consecutive months.
e. Percentage of LGS customers who trigger the Price Limit Band provision.

65.0 Reference: Exhibit B-1, Application, Section 6.4.2.1 Existing LGS Energy Rate, p. 6-42
New accounts pricing (85/15 Pricing Rule)

The mechanism of LGS rate structure include a provision for new accounts where the last 15 percent of energy consumed in a monthly billing period will be charged at the Part 2 energy rate rather than at the Part 1 energy rate until a baseline level of consumption is established one year hence.

65.1 Since the implementation of the LGS rate, how many new accounts have used 85/15 pricing? Please compare this group to the percentage of LGS customer who consume only at Part 1 rate for at least 12 consecutive months.

65.2 Does the 85/15 pricing also apply to MGS customers? If so, please provide the information as in the question above.

65.3 Does the 85/15 pricing also apply to incremental load under Tariff Supplement (TS) 82? If so, please provide the frequency that TS 82 has been applied since its implementation.

66.0 Reference: Exhibit B-1, Application, Sections 6.4.2 & 6.4.3 Large General Service, pp. 6-43 to 6-49
Large General Service Conservation

On page 6-43, BC Hydro states "…the key issue with the existing LGS two-part energy rate is that it does not provide a clear price signal for conservation and is poorly understood by customers. The result is that minimal conservation savings have been delivered to date, and that BC Hydro cannot count on and does not forecast any conservation savings going forward."

On page 6-46, BC Hydro states "The LGS two-part energy rate has been evaluated through the 2011-2012 LGS and MGS Evaluation Report and F2014 LGS and MGS Evaluation Report to have delivered lower than expected conservation savings with a declining confidence in the persistence of the savings…"

On page 6-48, BC Hydro states "LGS customers may have greater, longer lasting responses if they understand the details of the rate well enough to quantify the benefits they may receive by responding."

On page 6-49, BC Hydro states:

> The reason for carrying forward the SQ LGS Simplified Energy Rate is that in contrast to the MGS rate: the LGS energy rate has resulted in some energy conservation; some LGS

customers desire to retain the baseline-based rate structure; and as described below, the LGS flat energy rate is not reflective of the energy LRMC range, so simplification does in this case have some trade-off with losses in efficiency and conservation.

66.1 Since the current LGS rate structure has delivered some energy savings, what initiatives could BC Hydro undertake to improve customer understanding of the rate features and see if that results in improved future savings? Should these educational initiatives be undertaken now and the existing rate re-evaluated in the next RDA?

66.2 Please explain the difference between the previous projected conservation savings (i.e., 780 GWh for F2014) and the current forecast by detailing the assumptions and methodologies used.

67.0 Reference: Exhibit B-1, Application, Sections 6.4.2 Large General Service, p. 6-45 Figure 6-9 Large General Service heterogeneity

67.1 Would BC Hydro agree that while the LGS class is heterogeneous, Figure 6-9 seems to indicate that it is less so than the MGS class? If not, please explain.

67.2 Looking at the number of customer types with medium consumption at or below 1 MW, would the diversity in the class be improved by the creation of an X-LGS class for customers over 1 MW?

68.0 Reference: Exhibit B-1, Application, Sections 6.4.3.2 Large General Service, p. 6-46 Extra Large General Service

BC Hydro states "Awareness and demonstrated understanding of the LGS rates was low. About

35 per cent of LGS customers correctly identified the two-part energy rate as applicable across four possible rate structure selections. Larger customers generally have higher unaided awareness than smaller customers."

68.1 Would the above statement support both the creation of an X-LGS class and the proposed shift to a flat rate for the remaining LGS customers? Why or why not?

69.0 Reference: Exhibit B-1, Application, Section 6.4.3.2 Results of Evaluation, Table 6-17, pp. 6-46 and 6-48 Cumulative net evaluated conservation savings; gigawatt hours per year

Table 6-17 summarizes the evaluated conservation savings for fiscal 2014 and calendar 2013 and calendar 2012 at different levels of statistical significance.

69.1 Please reconcile the discrepancy in Table 6-17 with the F2014 Evaluation Report Table 3.7 in Appendix C4 that shows 200 GWh/year savings for the end of 2012 and 144 GWh/year were for end of 2011.

On page 6-48, BC Hydro states its finding that awareness of the LGS rate was not required for a conservation response. It believes that this may offer an explanation of why LGS energy savings have diminished over time.

69.2 Since the savings are reportedly cumulative net savings as opposed to new savings, rather than concluding that awareness was not required for a conservation response, is it more accurate to describe that the diminished energy savings were a result of savings that were unable to persist over time?

70.0 Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-52 Large General Service

BC Hydro states "One customer, Loblaws, preferred the existing LS-1 energy rate, which it states provides a clear price signal to conserve electricity."

70.1 Would Loblaws be a large enough customer to be included in an X-LGS class?

70.2 Are there lessons that could be learned from Loblaws on how to educate other LGS customers to take advantage of the existing LGS rate to conserve electricity?

71.0 Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-55 Large General Service flat energy rate

BC Hydro states:

> LGS Flat Energy Rate - A LGS flat energy rate eliminates all complexity-related issues resulting from the baseline component of the SQ LGS Energy Rate and aligns with how other similarly situated Canadian electric utilities structure larger general service energy rates (predominantly flat). However, there is a trade-off between the customer understanding and acceptance and the economic efficiency criteria because the flat energy rate would not be reflective of LRMC (F2017: LGS flat energy rate is 5.37 cents/kWh with demand charge cost recovery at 65 per cent, and the lower end of the energy LRMC range is 9.46 cents/kWh).

71.1 How has BC Hydro applied its rate design objectives and priorities to weigh the LGS flat energy rate attributes of simplicity, understandability and economic efficiency to come to the conclusion that a flat energy charge is best for the LGS customers?

72.0 Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-57 Extra Large General Service rate

BC Hydro states

> While BC Hydro set out considerations for a LGS TSR-Like Rate as a potential rate design for very high consumption LGS customers, it noted that its consideration of a LGS TSR-Like Rate and a segmented LGS class would be proposed only in the overall context of a LGS Flat Energy Rate applicable to the remaining majority of LGS customers. With the support of stakeholders, notably AMPC, a LGS TSR-Like Rate will be explored in RDA Module 2.

72.1 Why does BC Hydro limit the consideration of a TSR-like rate to the approval of a flat LGS energy charge?

72.2 Can BC Hydro provide further clarity on its plans for a TSR-like rate for the largest LGS customers since it may have a bearing on the acceptance of BC Hydro's proposed flat energy and flat demand charges for the remainder of the LGS class?

72.2.1 Would the TSR-like LGS rate for high consumption LGS customers include features of the TSR rate such as the use of bill neutrality definition?

72.3 Based on BC Hydro's knowledge of the customers that may become eligible for the TSR-like rate, how likely are they to take advantage of the new rate to achieve meaningful conservation?

72.4 BC Hydro has intimated that the X-LGS threshold for eligibility may be set at about 2 MW. Please provide a discussion of the number of customers that would be eligible for the rate and its likely conservation potential if the threshold were set at 1 MW, 1.5 MW or 2 MW?

73.0 Reference: Exhibit B-1, Application, Section 6.4.4.2 Screening of Alternatives and Stakeholder Engagement, p. 6-58
Demand cost recovery

On page 6-58, BC Hydro indicates that an increase in LGS demand charge recovery of demand costs from about 50 percent to 65 percent would be a level consistent with RS 1823 demand cost recovery. It further says that an increase in demand cost recovery will improve fairness in cost allocation and will further offset the impacts of energy rate flattening.

73.1 BC Hydro describes in the Application that the LGS is a heterogeneous group with the median consumption by site type having a very large range. Why is it important for the LGS rate class to have its recovery of demand cost consistent with RS 1823 and not consistent with the MGS rate class recovery?

73.2 In the past three years, what were the migration pattern between MGS and LGS? What were the bill impacts under the existing tariffs for those who migrated?

74.0 Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-59
Large General Service rate

BC Hydro states "BC Hydro prefers to maintain the level of the LGS demand ratchet at the existing level of 50 per cent of peak monthly demand given that the level of the demand ratchet is not a major issue."

74.1 From a customer fairness perspective, would a 75 percent ratchet be fairer overall to customers in the LGS class than a 50 percent ratchet?

74.2 If an X-LGS class were created, would the appropriate demand ratchet be 50 percent or 75 percent? Why?

75.0 Reference: Exhibit B-1, Application, Section 6.4.5.1 LGS Flat Rate, p. 6-60
Trade-offs of Bonbright criteria

On page 6-60, BC Hydro says that the gains in simplification in moving to a flat energy rate appear to be worth the apparent small loss in economic efficiency in the status quo LGS rate design.

75.1 According to the figures in Table 6-10 on page 6-50, the flat energy rate will be 5.37 cents/kWh under the 65 percent demand-related cost recovery. Please explain how BC Hydro reaches its conclusion on the "small losses in economic efficiency."

75.2 Will the new flat rate under either demand charge recovery scenario encourage energy conservation in electricity? Has BC Hydro made any projections of the increase in electric consumption against the status quo under the 65 percent demand-related cost recovery? What is the price elasticity assumed for flat rate consumption?

76.0 Reference: Exhibit B-1, Application, Section 6.4.3.2, Evaluation Results, p. 6-47, and Section 6.4.5.1 LGS Flat Rate, p. 6-60
Simplified energy rate and flat energy rate

The LGS evaluation results indicate that the status quo LGS is administratively complex and BC Hydro had encountered significant operational challenges.

76.1 Has BC Hydro made any estimates in regard to the savings in administration and operational costs if either the simplified energy rate or the flat energy flat rate is approved? If so, please provide the savings benefits against the status quo rate.

77.0 Reference: Exhibit B-1, Application, Section 6.6 Requested Order New Account Rule, pp. 6-70 and 6-71
Change in ownership and85/15 pricing energy rate and flat energy rate

On page 6-70, BC Hydro states that in its previous 2009 LGS Application, BC Hydro proposed 90 percent of monthly consumption billed at Part 1 energy rate and 10 percent of monthly consumption billed at the Part 2 energy rate. The 10 percent was increased to 15 percent during the LGS NSA.

The 85/15 pricing applies to new accounts (e.g., those opened as a result of a legal change in ownership) that have taken over existing businesses and not changed operations. There have been a number of LGS and MGS customer complaints about the 85/15 pricing.

77.1 Does BC Hydro agree that in the regulatory context, a change in ownership may be the basis of a rate's availability or the application of conditions to serving a rate? For example: (a) in the 1991 RDA Decision, it was determined that BC Hydro may terminate rate availability when there is a change in ownership to RS 1278 (see page 6-3); and (b) for E-plus rates to residential and commercial customers, a change in ownership would restrict the ability to transfer the E-plus rate to a new customer (see page 5-49).

78.0 Reference: Exhibit B-1, Application, Section 6.6 Requested Order New Account Rule, p. 6-70; Exhibit A2-1 BC Hydro request for reconsideration of Order G-64-11
Requested order for LGS and MGS new account rule

In the 2009 LGS Application, BC Hydro proposed 90 percent of monthly consumption billed at the Part 2 energy rate. The 10 percent was increased to 15 percent during the LGS Negotiated Settlement Agreement. This was to reduce the concerns expressed by some stakeholders that existing customers with growing load might open new accounts to have their Historic Baselines (HBL) reset and to obtain bill savings.

78.1 TS 82 provides for explicit pricing rules for eligible LGS customers with prospective growth, which is the 85/15 rule. Does BC Hydro agree that the 85/15 pricing is not just for the new account but also for incremental load?

78.2 In BC Hydro's view, why is it reasonable to eliminate the 85/15 pricing for new accounts in an accelerated manner, effective January 2016, but not for incremental load?

In Exhibit A2-1, a BC Hydro letter dated April 18, 2011 requested a reconsideration of Order G-64-11. Page 4 of 5 in the letter states: "85/15 Pricing is an appropriate price signal to new load that BC Hydro would otherwise serve at embedded cost." On page 6-71, lines 13 to 16, BC Hydro says that " BC Hydro proposes that new MGS and LGS accounts pay 100 percent Part 1 Pricing. This pricing recovers BC Hydro's embedded costs and therefore does not harm other ratepayers. Although new accounts will not be exposed to the LRMC price signal, this will be for a one year period only."

78.3 Please explain why BC Hydro on page 6-71, line 14 describes that a one year period is acceptable for new accounts not being exposed to the LRMC.

In Exhibit A2-1, on page 4 of 5, BC Hydro states:

> Neither the Interfor Application nor the impugned order address the issue of fairness between new accounts and existing accounts with "significant, permanent increases in energy consumption" as defined in section 13 of the LGS NSA. Thus, on the face, the effect of BCUC Order No. G-64-11 is *prima facie* an undue preference to existing customers vis-à-vis new customers subject to the 85-15 rule.

78.4 Please address the fairness issue in the accelerated request for a change in pricing for the new account rule?

79.0 Reference: Exhibit B-1, Application, Section 6.5.1 Medium General Service, p. 6-68 Medium General Service phase-in

On page 6-68 BC Hydro states

> A three-year phase-in period for BC Hydro's preferred MGS rate (F2017-F2019) would have only minor mitigation of bill impacts as compared to no phase-in (i.e., one-time F2018 implementation) impacts:
>
> - Under a three-year phase-in, customers who experience adverse bill impacts greater than 10 per cent are limited to about 800 accounts with less than about 40 MWh/year of annual consumption; and
> - For the majority of MGS customers the three-year phase-in will delay the offsetting effect of the flat energy rate, flat demand charge and increasing demand cost recovery. "

And "The three-year phase-in is highly complex. While there are some softening of bill impacts for high load factor, high consuming customers, the key trade-off is an expected decline in customer understanding and bill predictability.

79.1 Please expand on the "highly complex" nature of a three-year phase-in?

79.2 Please explain how BC Hydro evaluated and weighted the competing rate design objectives of bill complexity, customer impacts and conservation to conclude that no phase-in was preferable for MGS customers?

80.0 Reference: Exhibit B-1, Application, Section 6.5.1 Medium General Service, p. 6-68
Figure 6-15 Medium General Service three year phase-in bill impacts

Figure 6-15 Three Year MGS Proposed Rates Phase-In

	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	11.5%	11.9%	8.2%	7.3%	6.9%	1.2%	-4.4%	-7.4%	-9.6%	-11.2%	-12.5%	-13.5%	-14.3%	-15.0%	-15.6%	-16.1%	-16.6%
20%	4.8%	4.9%	4.9%	4.1%	3.8%	3.6%	3.6%	4.8%	5.8%	5.7%	3.4%	1.6%	0.1%	-1.2%	-2.2%	-3.1%	-3.9%
30%	2.6%	2.5%	2.5%	2.5%	2.2%	2.1%	2.1%	3.5%	4.5%	5.4%	6.1%	6.6%	7.1%	7.6%	6.4%	5.3%	4.2%
40%	1.5%	1.3%	1.3%	1.3%	1.3%	1.2%	1.2%	2.6%	3.8%	4.6%	5.4%	6.0%	6.5%	6.9%	7.3%	7.7%	8.0%
50%	0.8%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	2.1%	3.2%	4.2%	4.9%	5.6%	6.1%	6.5%	6.9%	7.3%	7.6%
60%	0.4%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	1.7%	2.9%	3.8%	4.6%	5.2%	5.8%	6.3%	6.7%	7.0%	7.3%
70%	0.1%	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%	-0.1%	1.4%	2.6%	3.6%	4.4%	5.0%	5.6%	6.0%	6.5%	6.8%	7.2%
80%	-0.2%	-0.4%	-0.5%	-0.5%	-0.5%	-0.5%	-0.4%	1.2%	2.4%	3.4%	4.2%	4.8%	5.4%	5.9%	6.3%	6.7%	7.0%
90%	-0.4%	-0.6%	-0.7%	-0.7%	-0.7%	-0.7%	-0.6%	1.0%	2.2%	3.2%	4.0%	4.7%	5.3%	5.7%	6.2%	6.5%	6.9%

80.1 Please confirm, otherwise explain, that Figure 6-15 shows the summation of the bill impacts of the three-year phase-in period.

80.2 Please provide a bill impact table similar to Figure 6-15 for each year of three year phase-in period.

81.0 Reference: Exhibit B-1, Application, Section 6.5.2 Large General Service, p. 6-70
Figure 6-17 Large General Service three year phase-in bill impacts

Figure 6-17 Three Year LGS Preferred Rates Phase-In

	150,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	25.2%	2.4%	-1.5%	-3.3%	-4.5%	-5.2%	-5.8%	-6.2%	-6.5%	-6.7%	-6.9%	-7.1%	-7.2%	-7.4%	-7.5%	-7.6%	-7.6%
20%	13.8%	12.3%	6.1%	[illegible]	[illegible]	0.0%	-0.8%	-1.5%	-2.0%	-2.4%	-2.7%	-3.0%	-3.2%	-3.4%	-3.5%	-3.7%	-3.8%
30%	4.2%	19.0%	11.1%	7.3%	5.0%	3.5%	2.4%	1.6%	1.0%	0.5%	0.1%	-0.2%	-0.5%	-0.8%	-1.0%	-1.2%	-1.3%
40%	-1.4%	13.7%	14.7%	10.3%	7.7%	6.0%	4.7%	3.8%	3.1%	2.5%	2.1%	1.7%	1.4%	1.1%	0.8%	0.6%	0.5%
50%	-4.9%	9.8%	14.8%	12.6%	9.7%	7.8%	6.5%	5.5%	4.7%	4.1%	3.6%	3.1%	2.8%	2.5%	2.2%	2.0%	1.8%
60%	-6.1%	6.9%	11.9%	14.3%	11.3%	9.2%	7.8%	6.7%	5.9%	5.2%	4.7%	4.2%	3.9%	3.5%	3.3%	3.0%	2.8%
70%	-7.1%	4.8%	9.7%	12.5%	[illegible]	[illegible]	8.9%	7.7%	6.9%	6.2%	5.6%	5.1%	4.7%	4.4%	4.1%	3.8%	3.6%
80%	-7.8%	3.2%	8.0%	10.7%	12.5%	11.3%	9.7%	8.6%	7.7%	6.9%	6.3%	5.9%	5.4%	5.1%	4.8%	4.5%	4.3%
90%	-8.3%	1.9%	6.6%	9.4%	11.1%	12.1%	10.5%	9.3%	8.3%	7.6%	7.0%	6.5%	6.0%	5.7%	5.3%	5.1%	4.8%

81.1 Please confirm, otherwise explain, that Figure 6-17 shows the summation of the bill impacts of the three-year phase-in period.

81.2 Please provide a bill impact table similar to Figure 6-17 for each year of three-year phase-in period.

82.0 Reference: Exhibit B-1, Application, p. 6-37, 6-56 and 6-67
Figure 6-17 Medium General Service phase-in

In the Application BC Hydro notes on page 6-56: "AMPC questioned whether higher bill impacts to high load factor and high consumption customers would be fair and acceptable given that such customers make more efficient use of BC Hydro's system." Further, BC Hydro notes on page 6-37 "AMPC notes that

it believes that the MGS Demand Sensitivity outcome is not acceptable given that high load factor customers make more efficient use of BC Hydro's system."

And explains on page 6-67:

> The benefits of more efficient rate design is that they would encourage efficient customer behavior that would lower customer bills in the future and it made sense that rates could transition to being more efficient to mitigate severe bill impacts on a few customers for the benefit of all customers…BC Hydro is proposing to redesign rates that unfairly allocate fixed costs among customers and have been doing so for some time now. Delays or lengthy transitions lengthen the time that some customers are required to subsidize others.

BC Hydro further explains on page 6-68: "The three-year phase-in is highly complex. While there are some softening of bill impacts for high load factor, high consuming customers, the key trade-off is an expected decline in customer understanding and bill predictability."

82.1 Please explain what BC Hydro considers efficient customer behavior.

82.2 Please explain how BC Hydro calculates load factor. Assuming all else equal, does BC Hydro consider a customer consuming with a higher load factor a more efficient customer than one with a low load factor, or vice versa? Please explain.

82.3 Under the current rate structure, are high load factor customers subsidizing low load factor customers, or vice versa? Please explain.

82.4 Under the current rate structure, are fixed costs being unfairly allocated to low load factor customers as compared to high load factor customers? Please explain.

82.5 It appears that high load factor / high consumption MGS and LGS customers would benefit from a three-year phase-in plan. Please explain how the benefits to high load factor / high consumption were traded off and weighed against customer understanding and bill predictability.

83.0 Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, pp. 6-62, 6-65, 6-66 and Table 6-20
Large General Service rate

On page 6-62, BC Hydro states "Increasing the level of demand-cost recovery through the flat demand charge from ~50 per cent to 65 per cent will improve fairness in cost allocation and will further offset the impacts of energy rate flattening and dampen the range of bill impact variation among LGS customers across size and load factor."

On page 6-65, BC Hydro states "The larger consuming customers tend to have minimal impacts during the transition, while the low load factor, and low consumption tend to see the biggest impacts due to charges on the first 35 kW of demand."

And on page 6-66, it says that "AMPC argues that the LGS Demand Sensitivity outcome is not acceptable given that high load factor customers make more efficient use of BC Hydro's system."

83.1 Table 6-20 indicates that the 50 percent demand cost recovery sensitivity only increases the flat energy rate from 5.37 cents/ kWh to 5.98 cents / kWh. Since the energy rate remains well below LRMC, is it BC Hydro's view that either energy rate will attract similar levels of rate induced natural conservation?

83.2 The bill impact analysis undertaken by BC Hydro on pages 6-64 and 6-65 seems to indicate that maintaining the status quo 50 percent demand cost recovery has less impact on customer bills. Why then does BC Hydro prefer the 65 percent demand cost recovery? Is BC Hydro giving preference to the rate design objective of economic cost recovery over bill impacts? Please explain BC Hydro's analysis.

84.0 Reference: Exhibit B-1, Application, Sections 6.6 General Service, pp. 6-70 and 6-71
New Accounts in 2016

BC Hydro requests a final order effective January 1, 2016 approving a change in the pricing for new accounts that do not have a HBL on RS 15xx or RS 16xx from 85 per cent of monthly consumption billed at the Part 1 energy rate and 15 per cent of monthly consumption at the Part 2 energy rate (85/15 Pricing) to 100 per cent of the monthly consumption billed at the Part 1 energy rate (100 per cent Part 1 Pricing).

84.1 To the best of BC Hydro's knowledge, what is the likely number of new customers that will be impacted? Will any new customers in 2016 suffer harm if the requested order is not issued, effective January 1, 2016? If BC Hydro is not able to quantify the impact for 2016, please provide the number of impacted customers in the past three years F13, F14, and F15.

84.2 If the flat MGS and/or flat LGS energy proposals of BC Hydro are not approved after this RDA, whereas, a separate approval is granted for the amendment to the 85/15 pricing of new accounts, how does BC Hydro plan to address the issue of fairness in exposing all other customers to the LRMC. Please discuss.

85.0 Reference: Exhibit B-1, Application, Sections 6.8 General Service, p. 6-74
RS 1253

BC Hydro did not specifically discuss RS 1253 with stakeholders. However, as set out in section 7.4.2 of the Application, RS 1853 - which is available to IPP customers served at transmission voltage for forced outages, scheduled maintenance requirements and black-start re-energization of generators, and has identical energy rate pricing and monthly minimum charge was discussed at Workshops 5 and 10. The only issue identified concerning RS 1853 is whether the non-firm energy rate pricing should be aligned with another non-firm rate, RS 1880 – like RS 1253, RS 1853 is based on Mid-C market prices whereas RS 1880 is set to the prevailing RS 1823 Tier 2 rate. At Workshop 10, BC Hydro provided its view that non-firm energy sold to IPPs should be priced off the Mid-C market because non-firm energy acquired from IPPs is typically priced at Mid-C, thus ensuring that non-firm energy is consistently valued whether it flows from BC Hydro to the IPP customer or from the IPP service provider to BC Hydro.

85.1 For consistency between RS 1253 and RS 1853, is it BC Hydro's view that whichever pricing is set for RS 1853, the same pricing should apply to RS 1253? If not, please explain.

86.0 Reference: Exhibit B-1, Application Volume 4 of 5, Appendix C4, Evaluation of the Large and Medium General Service Conservation Rates, F2014, p. 15
Control group

BC Hydro randomly selected and assigned 400 accounts to a control group in 2010 before the implementation of new conservation rates, with 200 drawn from the MGS population and 200 drawn from the LGS population.

86.1 Please describe how it was determined that 400 control accounts would provide a good level of precision in evaluating energy savings due to the LGS and MGS conservation rates.

87.0 Reference: Exhibit B-1, Application Volume 4 of 5, Appendix C4, Evaluation of the Large and Medium General Service Conservation Rates, F2014, p. 28
Customer awareness, understanding and acceptance of the conservation rates

Customer surveys, customer focus groups and key account manager interviews were used to collect information related to customer awareness, understanding and acceptance of the MGS and LGS rates.

87.1 Would BC Hydro confirm that the survey results show that there is a higher percentage of customers who strongly support the rate (9 percent and 21 percent) than customers who strongly oppose the rate (5 percent to 7 percent)? If confirmed, what are the implications of this finding to BC Hydro's proposed rate structure?

87.2 Is it true that it is the mechanics of the rate that cause the most complaints from focus group participants and key account customers? If so, does it imply that some form of simplified conservation rate structure may still be desirable? Could educational initiatives overcome the complaints regarding rate complexity and thereby lead to improved conservation?

88.0 Reference: Exhibit B-1, Application Volume 4 of 5, Appendix C4, Evaluation of the Large and Medium General Service Conservation Rates, F2014, p. 29
Customer response to conservation rates

Customer surveys, customer focus groups and key account manager interviews were used to collect information related to customer awareness, understanding and acceptance of the MGS and LGS rates.

88.1 Would BC Hydro confirm that among those customers who could identify the energy charge component of their rate unaided, more customers indicated that the rate served as a major incentive to conserve (41 percent) versus those who indicated that it served as no incentive at all (35 percent)? If confirmed, does BC Hydro believe that the status quo MGS and LGS rate design offers some form of conservation incentives?

89.0 Reference: Exhibit B-1, Application Volume 4 of 5, Appendix C4, Evaluation of the Large and Medium General Service Conservation Rates, F2014, pp. 38, 39
Methodology to estimate energy and peak demand savings

In relation to the estimate of energy savings from the LGS conservation rate, the report shows the evaluated savings of 77 GWh/year at 85 percent confidence level for F2014.

The prior evaluation estimated net evaluated energy savings were 144 GWh/year by the end of 2011

and 200 GWh/year by the end of 2012. Moreover the Evaluation Report shows that energy savings estimates for 2011 and 2012 were statistically significant at the 90 percent confidence level.

89.1 Has any work been done to understand the drop in energy savings in F2014? If so, please provide the reference in the Evaluation Report. If no, please explain why not.

89.2 It is stated in the Evaluation Report that the 77 GWh/year savings are cumulative since the implementation of the conservation rates, and cannot be added to savings from 2012 and 2011. Does this statement imply that savings measured in earlier years failed to persist?

89.3 It is described in the Evaluation Report that the influence of parallel DSM initiatives is controlled for in the randomized control trial research design (page 24 of the Evaluation Report). In BC Hydro's view, is it likely that by the third year after the implementation, LGS and MGS customers have chosen to take up DSM initiatives for conservation as a result of the MGS and LGS conservation rates?

F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

90.0 Reference: Exhibit B-1, Application, Section 7.2 Transmission Service, p. 7-5, Table 7-1 RS 1823

BC Hydro shows that the average existing RS 1823 energy rate A is low compared to LRMC and that the tier 1 rate is very low at 3.836 cents/kWh. The energy rate A is a flat rate at 4.303 cents/kWh for new accounts.

90.1 Please provide a summary of the competing rate design objectives and legislative constraints as they impact the Tier 1 and Tier 2 pricing. For example, does BC Hydro feel constrained in keeping the Tier 2 price at the low end of LRMC because the Tier 1 price is already so low? Could the Demand charge be reduced to the LGS 50 percent cost recovery to allow for a higher Tier 2 price?

90.2 Is BC Hydro concerned that the new accounts that do not have CBLs will not get adequately exposed to the LRMC by taking service at the energy A flat rate in the first year?

90.3 Please compare and contrast this RS 1823 A flat rate with the flat rate proposed for the LGS MGS New Account Rule where 100 percent of the monthly consumption will be billed at the Part 1 energy rate.

91.0 Reference: Exhibit B-1, Application, Section 7.2 Transmission Service, pp. 7-7, 7-12 and 7-13 Defining "revenue neutrality"

On page 7-7, BC Hydro states that the Commission has jurisdiction over the "Definition of revenue (customer bill) neutrality, which differs from the forecast revenue neutral approach used for the Residential and SGS/MGS/LGS rate classes. The term "revenue neutrality" used in Recommendation #8 is not defined, and could be either customer bill neutrality or forecast revenue neutrality."

On page 7-12, it states that:

> BC Hydro is not seeking any order regarding the general application of a revenue

neutrality definition. BC Hydro is proposing pricing principles for three years (Option 1) that in all three years achieves customer bill neutrality; in two of the three years also achieves forecast revenue neutrality; and in the one-year it doesn't achieve forecast revenue neutrality (F2017), Tier 2 is within the energy LRMC range in accordance with the first element of Recommendation #8. The result is an approach that yields RS 1823 pricing that in F2018 and F2019 satisfies all of the requirements of Recommendation #8.

On page 7-13, it states "BC Hydro favours the customer bill neutrality approach to determine RS 1823 rates in F2017 so that the Tier 2 rate is set at the lower range of LRMC."

91.1 Please explain why BC Hydro does not seek a Commission determination of the definition of revenue neutrality? Would such a determination provide some certainty for future rate settings and RDAs? E.g., the design of X-LGS rate in module 2?

92.0 Reference: Exhibit B-1, Application, Section 7.2.2.2 Transmission Service, pp. 7-10, 7-12 and 7-13 RS 1823 Option 3 pricing

Option 3: In F2017, all of the RRA rate increase is applied to Tier 2 and Tier 1 is held constant at its F2016 level. For F2018, applying all of the RRA rate increase to Tier 2 results in Tier 2 being above the upper end of the LRMC range. As a result, Tier 2 is capped at the upper end of the LRMC range, and Tier 1 is adjusted accordingly. For F2019, both Tier 1 and Tier 2 are calculated as in F2018. Option 3 is not forecast revenue neutral. Option 3 reflects the prioritization of the Bonbright efficiency criterion by increasing Tier 2 to the upper end of the energy LRMC range." And "No stakeholder supports Option 3." And "Option 3 under-recovers revenue by $8.8 million, $12.0 million and $11.7 million for F2017, F2018 and F2019 respectively.

92.1 In your response, please provide Recommendation #8 of the Heritage Contract Report. Is Option 3 consistent with the intent of Recommendation 8? Why?

92.2 With no stakeholder support and under-recovery of allocated revenue requirement considerably higher than Options 1 or 2, why did BC Hydro carry Option 3 forward for consideration in this RDA?

93.0 Reference: Exhibit B-1, Application, Section 7.2.3.1 Transmission Service, p. 7-13 and Table 7-3 RS 1823 Options 1 and 2 pricing

On page 7-13, the Application shows that Option 1 under recovers revenue in F2017 by $2.2 million, and Option 2 under-recovers revenue by $2.2 million, $1.4 million and $0.9 million for F2017, F2018 and F2019 respectively.

93.1 Although BC Hydro favours Option 1 pricing, would it agree that the price differences between Options 1 and 2 are very small and that an advantage of Option 2 is to keep Tier 1 rates slightly above Option 1's Tier 1 rates in F2018 and F2019?

94.0 Reference: Exhibit B-1, Application, Section 7.2.3.2 Transmission Service, p. 7-14 RS 1823 Option 1 customer bill neutrality

"The customer bill neutrality definition aligns with Policy Action No. 21 of the 2002 Energy Plan..."

94.1 Please provide Policy Action No. 21 in your response. Please explain why BC Hydro believes that bill neutrality aligns with Policy Action 21 and why revenue neutrality does not?

95.0 Reference: Exhibit B-1, Application, Section 7.2.3.1 Bill Neutrality, pp. 7-12 to 7-14
BC Hydro proposal and stakeholder engagement

On page 7-14 of the Application, BC Hydro describes AMPC's position that the adoption of the forecast revenue neutrality approach is unacceptable to customers taking service under RS 1823 as it unfairly results in impacts to customers that have successfully conserved energy in response to the Tier 2 rate price signal. On the same page, BC Hydro also describes that the non-Transmission Service customer participants favour using the forecast revenue neutrality approach to ensure consistency with other classes.

BC Hydro uses the revenue-cost ratios from the F2014 FACOS and F2016 FACOS to indicate that the Transmission Service Rate class is not being subsidized by other rate classes.

95.1 Why is BC Hydro relying on the TSR R/C ratio as an argument to support bill neutrality? Shouldn't the merits of bill neutrality pricing and forecast revenue neutrality pricing be focused on revenue allocation as opposed to cost allocation?

95.2 Please confirm that the merits of whether a bill neutrality definition approach continues to be appropriate are influenced by BC Hydro's under-recovery of forecast revenue from the TSR class since the stepped rate's implementation.

95.3 BC Hydro describes AMPC's position that the forecast revenue neutrality approach unfairly results in impacts to customers that have successfully conserved energy in response to the Tier 2 rate price signal. Is BC Hydro able to provide an example of how this occurs?

96.0 Reference: Exhibit B-1, Application, Section 7.2.4.2 Transmission Service, p. 7-16
RS 1823 demand charges

"The amount of demand-related costs the demand charge is recovering, at approximately 65 per cent of demand-related costs identified in the F2016 COS study, is appropriate."

96.1 BC Hydro identifies that a higher level of demand cost recovery would drive the Tier 2 price below LRMC. Please also provide BC Hydro's reasons for not considering a decrease in demand cost recovery to maintain a higher Tier 2 price.

96.2 What are the comparable Canadian electric utilities transmission class demand cost recovery percentages?

97.0 Reference: Exhibit B-1, Application, Section 7.3.1 Transmission Service, pp. 7-19, 7-20 and 7-21
RS 1825

On page 7-19, BC Hydro states "Since its implementation on April 1, 2006, no Transmission Service customer has taken service under RS 1825."

On page 7-20, "BC Hydro stated that, in its view, it is not possible to design an optional cost-based TOU rate that provides sufficient price differentials and/or offers Transmission Service customers more benefits than RS 1823…" And "AMPC reasoned that overall complexity, low margins, price risk and the current three-year commitment requirement combine to make RS 1825 less attractive to Transmission Service customers than RS 1823."

On page 7-21"… in BC Hydro's view it is unlikely that there can be a significant enough difference between on-peak and off-peak rates to encourage a change in consumption patterns."

97.1 Should RS 1825 be terminated if it cannot be reconfigured to be successful? Why?

97.2 Are the current and forecast very low natural gas commodity prices likely to ensure that the differentials between on and off peak rates remain inadequate to attract customers to RS 1825?

98.0 Reference: Exhibit B-1, Application, Section 7.3.2 Transmission Service, pp. 7-22 & 7-23 RS 1852

BC Hydro proposes a change in the current RS 1852 definition of HLH (06:00 hours to 10:00 hours and 16:00 hours to 20:00 hours, Monday through Friday, except for Statutory holidays), to provide BC Hydro discretion to determine the HLH periods that will apply based on a customer location/region which affords BC Hydro the option to curtail to alleviate potential local or regional transmission constraints or take advantage of a market opportunity.

On pages 6-22 to 6-23, BC Hydro states

Only one Transmission Service customer has taken service under RS 1852 at any one time.

RS 1852 was originally designed around Vancouver Island's unique two peak system load (6 a.m. to 10 a.m. and 4 p.m. to 8 p.m.). However, as demonstrated in section 4.2 of the Consideration Memo, the South Peace region does not have a two peak system load. Areas that may be transmission constrained in the future include the Lower Mainland (depending on the number of LNG proposals that proceed) and the North Coast/Prince Rupert region."

RS 1852 is complex and best suited for customers with large, discrete load centres, load control systems, and product storage or ability to 'make up' lost production". BC Hydro is also proposing to amend the definition of Availability in RS 1852.

98.1 Which customers have taken service under RS 1852 and what circumstances led to them taking and terminating service?

98.2 Given the complexity of RS 1852 and the customer requirements to take advantage of the rate, is there a reasonable prospect that it will be used in the future? Are there sufficient benefits to BC Hydro and its other ratepayers to continue the service, or should RS 1852 be discontinued?

98.3 According to BC Hydro, transmission constraints change over time and by location. In order to better understand the system demand issues, please provide a description of the time periods and location transmission constraints since RS 1852 was established and BC Hydro's projected transmission constraint time periods and location in the next five years.

98.4 BC Hydro describes the central issue with the RS 1852 is to address the low take-up. Please

describe the opportunity lost in terms of value to BC Hydro due to the lack of customers in the past five years.

99.0 Reference: Exhibit B-1, Application, Section 7.3.3 Transmission Service, p. 7-24 and section 2.4 of Workshop 5 memo
Retail access

While the IEPR task force recommended that BC Hydro develop a revised retail access program, the LGIC subsequently issued Direction No. 7; section 14 prevents the Commission from setting rates that result in direct or indirect provision of unbundled transmission service to retail customers in BC Hydro's service area or those who supply such customers, except on application by BC Hydro.

99.1 Given the complications identified by BC Hydro to implement a retail access program that would be fair to other customers, what conditions in the future would induce BC Hydro to make a voluntary application for retail access.

100.0 Reference: Exhibit B-1, Application, Section 7.3.3 Transmission Service, pp. 7-25 & 7-26
Real time pricing

BC Hydro states on pages 7-25 and 7-26 that:

> it would be difficult to integrate a stepped rate structure into RTP; the CBL could be priced at the stepped rate, but the marginal price signal would be spot market pricing and not BC Hydro's energy LRMC. The hybrid RTP rate would be asymmetrical if customers receive an energy LRMC price signal for saving energy (i.e., Tier 2 credit) but then receive a market price signal for increasing energy consumption.

100.1 Please provide an example to further explain the above quote?

101.0 Reference: Exhibit B-1, Application, Section 7.3.4 Transmission Service, pp. 7-26 and 7-32
Freshet rate pilot

On page 7-26, "BC Hydro seeks approval of the freshet rate no later than February 1, 2016 as a two-year pilot to run between the May to July 2016 and May to July 2017 freshet periods."

On page 7-32:

> During Workshop 10, BC Hydro acknowledged there are uncertainties associated with the freshet rate including take-up volumes. The best way to explore this while limiting risk to non-participating customers is to run the rate as a pilot for a period of time and evaluate results against predefined evaluation criteria (discussed below in section 7.3.4.6). BC Hydro considers that a two-year pilot is necessary to test the sensitivity of incremental load to changing market prices and to provide customers with sufficient potential benefit from the pilot to promote take-up. Stakeholders generally supported BC Hydro's two-year proposal.

101.1 Please provide any examples that BC Hydro is aware of where a new rate or program was initiated as a pilot and then reviewed and improved after an initial trial period.

101.2 Would establishing a rate and reviewing the rate after several years work equally well as a pilot program?

101.3 Please provide the anticipated costs in 2015$ of administering and reporting on the freshet rate during the pilot period.

102.0 Reference: Exhibit B-1, Application, Section 7.3.4.1 Transmission Service, p. 7-26; Figure 7-3 Freshet rate pilot

On page 7-26 of the Application BC Hydro concludes "The freshet rate would encourage customers to increase electricity consumption during the freshet period (May – July), when BC Hydro has a long-term recurring issue of energy oversupply."

102.1 Please discuss whether or not the oversupply is region specific. Could a freshet rate for specific oversupplied areas be more beneficial than providing for a freshet rate that is accessible to all RS 1823 customers across the province? Please elaborate.

102.2 Please compare the total energy available in each of BC Hydro's major reservoirs from their highest allowed annual operating level to their lowest allowed annual operating level to the energy expected from IPP, BC Hydro run-of-river, and other generation sources during the freshet period.

102.3 Please confirm, otherwise explain, that run-of-river and other forms of energy production in BC (e.g. wind) that take place during the spring and early summer period allow BC Hydro to fill its large reservoirs (e.g. Kinbasket, Williston, Kootenay, Arrow) and store this energy for more optimal use in the winter.

102.3.1 If confirmed, does operating the BC system in such a manner allow BC Hydro to provide energy/capacity to its customers in the winter at cheaper rates than market prices during the winter?

102.3.2 Similarly, does operating the BC system in such a manner allow BC Hydro and/or Powerex to export power at higher prices in the winter?

102.3.3 If customers consume additional energy during the freshet period, would this reduce the amount of power BC Hydro and/or Powerex would otherwise have available to export in the winter and/or sell to its customers? Please explain.

102.3.4 What value does the loss of this arbitrage opportunity have?

103.0 Reference: Exhibit B-1, Application, Section 7.3.4 Transmission Service, pp. 7-27 and 7-28 Freshet rate pilot

On pages 7-27 and 7-28, BC Hydro's describes its objectives as follows:

1. Respond to the IEPR task force's recommendation to develop additional options for industrial customers;
2. Assist in the management of the freshet oversupply in the BC Hydro system by providing the option to:
    - increase the ability to import cheap electricity during low priced periods;

- reduce the volume of surplus energy being forced to export markets; and/or
- reduce spill at BC Hydro facilities; and

3. Recover what BC Hydro would otherwise obtain on the export market, but with potential economic benefits for B.C.

103.1 Should there be a fourth objective to "share the benefits from the freshet rate with all BC Hydro ratepayers"? Why or why not?

104.0 Reference: Exhibit B-1, Application, Section 7.3.4 Transmission Service, Figure 7-2 Freshet rate pilot

"Figure 7-2, based on normal water conditions and forecast calendar 2017 load and generation, shows that system inflows and contracted IPP supply (Total EPAs) on the BC Hydro system are expected to exceed load by a significant margin between mid-April and the end of August."

104.1 Please provide similar figures based on actual inflows in 2013, 2014 and 2015. Based on those actual inflows, what impact would they have had on the availability of Freshet electricity?

104.2 Please provide an updated Figure 7-2 to show the impact of storing water as well as serving load.

105.0 Reference: Exhibit B-1, Application, Section 7.3.4 Transmission Service, p. 7-29 & Workshop 10 slide 22 Freshet rate pilot

"During the freshet period, there is a higher risk of minimum generation constraints which reduce BC Hydro's flexibility to take advantage of low Mid-C prices, especially in LLH, by importing more energy from the U.S. market."

105.1 Please further explain the impact of minimum generation constraints shown on the figure at slide 22 of Workshop 10.

106.0 Reference: Exhibit B-1, Application, Section 7.3.4 Transmission Service, pp. 7-29, 7-30 Freshet rate pilot

BC Hydro describes the 2015 freshet period as unusual due to early melt of winter snowpack and low rainfall across the freshet months. As a result, overall flow for the May to July 2015 period in the US Columbia River was the third lowest in 55 years. Consequently, Canadian dollar Mid-C market prices during the 2015 freshet were considerably higher than past periods given these drought conditions and a significant depreciation in the Canadian/US dollar exchange rate from an average of 0.97 in the period 2010 to 2014 to an average of 0.80 during the first seven months of 2015.

106.1 If the drought conditions of 2015 reoccur during the freshet rate pilot period, does BC Hydro anticipate that the higher prices and lower availability could result in revenue under collection and risk of future cost recovery from non-participating customers? Please explain why or why not.

107.0 Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, p. 7-35 & Workshop 10 memo, p. 34
Freshet Rate Pilot

On page 7-35, BC Hydro states "Initially, freshet energy volumes will be calculated hourly by determining energy consumption in excess of an average MW (**aMW**) baseline determined in consultation with the participating customer."

> BC Hydro sought feedback on four baseline options on slide 27 of the Workshop 10 presentation and ultimately received broad stakeholder support for pursuing Option 3, an average MW baseline discussed on page 34 of the Workshop 10 consideration memo, giving customers the ability to respond to daily HLH and LLH price signals. Options 1 and 2 were rejected because they used average freshet prices, across an entire month or season, and would have sent customers an inferior price signal relative to the use of an average MW baseline in Option 3.

First Nations Energy and Mining Council (FNEMC) suggested in Workshop 10 that different lengths of baseline periods (3 months, monthly, daily, hourly) be evaluated.

107.1 Is there a way that FNEMC's suggestions on page 34 of the Workshop 10 Consideration Memo can be evaluated during the pilot period?

108.0 Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, pp. 7-37 and 7-38
Freshet rate pilot

On page 7-37, BC Hydro states that "In the Workshop 10 presentation slide deck and consideration memo, BC Hydro stated the wheeling fee was both a cost recovery mechanism and a tool to protect non-participating ratepayers from risks associated with the freshet rate. BC Hydro now proposes a lower proxy (fixed at $CDN 3/MWh) for the following reasons." The reasons provided are: (a) cost justification and (b) risk justification.

BC Hydro considers a proxy wheeling fee of $CDN 3/MWh appropriate given the cost rationale and the fact there are risks to non-participating customers. This proposed fee is approximately 50 percent of the BPA wheeling fee that BC Hydro proposed at Workshop 10.

108.1 Why did BC Hydro decrease the proposed wheeling fee from the original suggestion of $6/MWh?

108.2 Are there likely cases where the higher $6/MWh fee would inhibit use of the freshet rate?

108.3 Can an appropriate wheeling rate be evaluated during the pilot period to set an appropriate fee for a later permanent program?

109.0 Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, p. 7-38
Freshet rate pilot

BC Hydro identifies the following risk to non-participating customers: "Tie line constraints may limit BC Hydro's ability to import from the U.S. market, which means storage could be the source of energy used to supply incremental freshet load. In this situation, there would be opportunity costs if BC Hydro could have instead used the stored energy during a higher valued period."

109.1 Would BC Hydro interrupt freshet rate deliveries in this circumstance? If not, what other measures could BC Hydro take to prevent or mitigate lost opportunities? Please explain.

110.0 Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, pp. 7-32 and 7-39 Freshet rate pilot

Regarding Reference Baselines, BC Hydro states "So long as 2015 freshet purchases are within +/- 10 per cent of a customer's historical freshet load, BC Hydro expects to use the 2015 data without further adjustment."

On page 7-32 BC Hydro explains: "The rate is open to any RS 1823 customer during the freshet period. BC Hydro excluded RS 1827 customers because many of these customers, including New Westminster, naturally increase consumption year over year and might benefit from the freshet rate without a behavioural change."

110.1 What period constitutes the "historical" freshet load?

110.2 Is this a change from the process identified on page 34 of the Workshop 10 Memo?

110.3 Please discuss how increased load in the Freshet Period due to natural load growth is accounted for. Do participants naturally benefit from natural load growth without a behavioral change under the Freshet Rate? If so, how does this affect non-participants?

111.0 Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, p. 7-40, Figure 7-6; Appendix C-5B, p. 38 Freshet rate pilot

Figure 7-6 shows estimated gains from a 1MW load.

In Appendix C-5B BC Hydro explains that it expects 5 to 30 MW of average incremental energy over the freshet period.

111.1 What is the total estimated increase in incremental energy consumption (MWh) over the Freshet Rate Freshet Period for each year of the pilot? How much is this worth to participants and non-participants?

111.2 Why is the 2015 gain to non-participating customers so large in comparison to the gain to the participating customer? Is this solely a result of the market impact of the drought conditions this past freshet period?

112.0 Reference: Exhibit B-1, Application, Section 7.3.4.5 Transmission Service, p. 7-42 Footnote 285 Freshet Rate Pilot

"For example, if shifting results in a drop in both RS 1823 Tier 1 revenue and long run marginal costs, there could be benefits to other ratepayers because the Tier 1 rate is significantly less than BC Hydro's LRMC. If shifting results in a drop in RS 1823 Tier 2 revenue, the outcome may be neutral for non-participating customers as the revenue reduction would be reasonably offset by the fall in long run costs."

112.1 Please further explain this footnote, perhaps with a numerical example.

113.0 Reference: Exhibit B-1, Application, Section 7.3.4.6 Transmission Service, p. 7-43
Freshet rate pilot

BC Hydro proposes a number of Evaluation Criteria. They are:

- Did the rate provide RS 1823 customers with lower cost options?
- Did the rate have positive or negative impacts on non-participating customers?
- How many RS 1823 customers used the rate" what were the volumes of use? How did customers use the rate?
- To what extent did shifting contribute to higher freshet energy?
- Was there any shifting within the freshet period from HLH to LLH? And
- Were there any issues with setting baselines, implementation and billing?

113.1 Please link the Evaluation Criteria to the program objectives on pages 7-27 and 7-28, including Commission suggested objective 4 to "share the benefits from the freshet rate with all BC Hydro ratepayers."

113.1.1 For example, considering BC Hydro suggests reducing spills at BC Hydro facilities could be a benefit of a freshet rate, could comparing spills at each BC Hydro generation facility year over year be an appropriate evaluation criteria? Please discuss.

114.0 Reference: Exhibit B-1, Application, Section 7.4, Transmission Service, p. 7-44
RS 1853 – IPP Station Service

"There is a minimum monthly charge currently set at $41.37 (F2016) to recover costs incurred by BC Hydro under RS 1853. BC Hydro would continue with its existing practice of applying RRA rate increases to the RS 1853 minimum monthly charge of $41.37 (F2016)."

114.1 Is $41.37 adequate to cover the monthly costs to BC Hydro? If not, wouldn't this RDA be the time to revise the monthly charge?

115.0 Reference: Exhibit B-1, Application, Section 7.4 Transmission Service, p. 7-45 & Workshop 10 Memo, pp. 49 and 50
Pricing of RS 1853 – IPP Station Service vs RS 1880 – Standby and Maintenance

On page 7-45, BC Hydro states:

Feedback from other stakeholders was limited, with the only issue identified concerning whether the energy rates for RS 1853 and RS 1880 should be aligned – RS 1853 is based on Mid-C market prices and RS 1880 is set to the prevailing RS 1823 Tier 2 rate. At Workshop 10, BC Hydro provided its view that non-firm energy sold to IPPs should be priced off the Mid-C market because non-firm energy acquired from IPPs is typically priced at Mid-C, thus ensuring that non-firm energy is consistently valued whether it flows from BC Hydro to the IPP customer or from the IPP service provider to BC Hydro.

115.1 BC Hydro seems to estimate that an additional $2 million might be collected from RS 1880 customers by using the expected higher RS 1823 Tier 2 price compared to Mid-C. RS 1880

customers seem to prefer the price certainty of the Tier 2 pricing compared to volatile Mid C prices. Is the lack of a material revenue difference between the two pricing concepts the main reason why BC Hydro proposes maintaining the status quo Tier 2 pricing for RS 1880?

115.2 Are there any other non-firm rate schedules with energy rates based on RS 1823 Tier 2 (e.g., shore power rate)? Please provide a list of the rate schedules.

115.3 Since the TSR was implemented, how frequently have spot market prices exceeded the RS 1823 Tier 2 rate?

115.4 If the Mid-C pricing is in a negative range, does BC Hydro still rely on Mid-C pricing for IPP customers taking services under TS 1853?

116.0 Reference: Exhibit B-1, Application, Section 7.4.3 Transmission Service, p. 7-46
RS 1880 – standby and maintenance

"There is an administrative charge of $150 per incident (period of use) to recover the incremental costs incurred by BC Hydro resulting from a customer's request for service under RS 1880. This charge has been unchanged since it came into effect in early 2006." And "While the RS 1880 administrative charge is reasonable, and while labour costs associated with administering RS 1880 (e.g., manual billing adjustments for RS 1880 requests) are minor, it is difficult to say with certainty whether the administrative charge under or over recovers actual labour costs."

116.1 What is BC Hydro's best estimate of the appropriate cost in F2016 and why was it not included in the RDA?

117.0 Reference: Exhibit B-1, Application, Section 7.5 Transmission Service, pp. 7-48 to 7-50
RS 1827 – exempt customers

On page 7-48, BC Hydro states that

> SFU and YVR took the position that a review of the reasons for exemption should not be examined as part of the 2015 RDA. A common element of their respective responses is that application of a stepped rate has not been required to induce investment in energy efficiency since a significant amount of DSM projects have been undertaken to date while receiving electrical service under RS 1827...

On page 7-49, BC Hydro states "While overall the RS 1827 energy charge is not an efficient rate as it is below BC Hydro's energy LRMC range, there does not appear to be any significant change in circumstance for SFU or YVR since their original exemption from stepped rates in 2006."

On page 7-50, BC Hydro states "… the B.C. Government is of the view that the Commission's original rationale for exempting SFU and YVR from RS 1823 and other stepped rates continues to apply."

117.1 Does BC Hydro have information related to the DSM investments of SFU and YVR in terms of total costs and conservation savings?

117.2 On a percentage basis, how have the DSM achievements of SFU and YVR compared with those of BC Hydro's residential customers, general service customers and industrial customers?

117.2.1 If they have been significantly less than BC Hydro's comparable customers, would BC Hydro seek a stepped pricing structure for SFU and YVR?

G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

118.0 Reference: Exhibit B-1, Section 8.2, p. 5-8 Electric Tariffs Terms and Conditions
Proposed review of standard charges between rate design applications

On page 8-5 of its Application, BC Hydro states that "RRAs are the appropriate forum for updates of existing Standard Charges to reflect current costs." BC Hydro seeks the Commission endorsement of the described review process.

118.1 Does BC Hydro propose that Standard Charges will be reviewed through the revenue requirement applications with the objective of applying approved rate changes to Standard Charges or only adjusting Standard Charges for inflation or some other index? Please discuss.

119.0 Reference: Exhibit B-1, Section 8.3.1, pp. 8-6 and 8-7
Minimum connection charges – 400A overhead

BC Hydro submits on page 8-7 of its Application the following:

> …due to system requirements 400A service requests often require additional transformation costs that are not included in the Minimum Connection Charge and would often require the creation of a distribution design for the installation which would include additional non-standard charges. To avoid customer confusion, BC Hydro is proposing to eliminate the 400A Minimum Connection Charge and address such service requests through the Distribution extension provisions in section 8 of the Electric Tariff.

119.1 For each of F2012, F2013 and F2014, please provide the number of 400A service requests received by BC Hydro, the total 400A service request revenue received and the average actual cost per 400A service request.

119.2 Please provide an updated 400A overhead service charge, including supporting calculations, using weighted average times and costs for BC Hydro's service area, and F2016 Standard Labour Rates (SLR), similar to the calculations provided in Appendix G-1B.

119.3 As noted in Chapter 1, (p. 1-14) BC Hydro is proposing to address section 8 of the Tariff, which governs distribution extensions, in RDA Module 2. Would it be preferable to also defer the decision to eliminate the Minimum Connection Charge for 400A service to Module 2, so that the elimination of the Minimum Connection Charge and its replacement with an amendment to section 8 of the Electric Tariff can be discussed at the same time? Why or why not?

119.3.1 Should the Commission approve a revised Minimum Connection Charge for 400A service, which would remain in place until such time as an amendment to section 8 of the Electric Tariff is approved? Why or why not?

119.4 For F2016, please provide the following information related to 400A service requests:

- Forecast number of service requests; and
- Calculations to support the forecast revenue and costs in the event that the service requests are addressed through a Minimum Connection Charge.

120.0 Reference: Exhibit B-1, Appendix G-1B, pp. 1-10
Minimum connection charges – total labour

The Minimum Connection Charges "Basis for Calculation" schedules found in Appendix G-1B of the BC Hydro Application include a loaded SLR of $143.57.

The SLR used in the determination of the Minimum Connection Charges in the 2007 RDA is $65.08.[1]

120.1 Please provide supporting calculations for the loaded SLR of $143.57, including a breakdown of the following components: base hourly rate, benefits, concessions and field loading.

120.1.1 Please confirm, or explain otherwise, that the loaded SLR of $143.57 relates to Power Line Technicians only.

120.1.2 Please provide the actual loaded SLR for Power Line Technicians for each of F2012, F2013 and F2014.

120.2 Please provide the reasons for the 120 percent increase in the SLR from $65.08 in the 2007 RDA to $143.57 in the 2015 RDA.

121.0 Reference: Exhibit B-1, Appendix G-1B, pp. 1 to10
Minimum Connection Charges – vehicle cost

The Minimum Connection Charges "Basis for Calculation" schedules found in Appendix G-1B of the BC Hydro Application include vehicle costs determined as 29 percent of the labour required.

121.1 Please provide supporting calculations for the 29 percent of labour required used to determine the vehicle costs with an explanation of the basis for this percentage.

121.2 Please explain the rationale for using a percentage of labour required to determine the vehicle costs, as opposed to vehicle hourly rate.

121.3 Please provide supporting calculations for the unloaded labour cost and crew cost.

121.4 For each of: Overhead 100 AMPS; Overhead 200 AMPS; Underground 100 AMPS; Underground 150 – 200 AMPS; First Subsequent Meter Installation; and Service Connection Call-Back Minimum Connection Charges, please provide the following:

- vehicle type used;
- hourly rate for vehicle type used; and
- calculation of vehicle cost input to the Minimum Connection charge using the hourly rate for the vehicle type used.

[1] BC Hydro 2007 Rate Design Application, Exhibit B-1, Appendix H.
http://www.bcuc.com/ApplicationView.aspx?ApplicationId=145

122.0 Reference: Exhibit B-1, Appendix G-1B, pp. 1-10
Minimum Connection Charges – overhead loadings

The minimum connection charges "Basis for Calculation" schedules found in Appendix G-1B of the BC Hydro Application include an overhead loading of 27 percent.

122.1 Please provide supporting calculations for the overhead loadings of 27 percent with an explanation of the basis for this percentage.

123.0 Reference: Exhibit B-1, Section 8.3.2, pp. 8-7 to 8-11
Minimum Reconnection Charge

On page 8-9 of its Application, BC Hydro lists the circumstances under which manual disconnections or reconnections are required, including when "[t]he premises does not have a meter enabled for [remote disconnect/reconnect (RDR)] (including legacy meters, poly-phase meters and some special metering types)".

On page 8-10 of its Application, BC Hydro submits that it "recently implemented a new process such that accounts are automatically disconnected 21 days after a customer terminates service unless a new customer has applied…Currently, there are approximately 1,000 vacant account disconnections each week, which exceeds the number of non-pay disconnections."

123.1 Does "automatically disconnected" for vacant account mean that no costs are incurred or are the disconnection costs absorbed by customers paying the Minimum Reconnection charge?

123.1.1 If the answer to the aforementioned IR is yes, please provide a revised proposed Minimum Reconnection Charge excluding disconnection costs for vacant account disconnections, or other disconnections where there is no reconnection and presumably no Manual Reconnection charge.

124.0 Reference: Exhibit B-1, Appendix G-1B, p. 7
Minimum Reconnection Charge

Page 7 of Appendix G-1B to the BC Hydro Application includes the breakdown of the costs included in the proposed Minimum Reconnection charge, for both regular hours and overtime, and the Refused Access Reconnection charge.

124.1 For the proposed Minimum Reconnection Charge for both regular hours and overtime, please provide a detailed demonstration of the calculation for each of the following cost inputs:

- ABSBC (Call Centre and Credit Review)
- Manual Disconnection
- Manual Reconnection

124.1.1 Please identify the changes in the methodology used to calculate the proposed Minimum Reconnection Charge as compared to the methodology used to calculate the charge put forward in the 2007 BC Hydro RDA.

124.2 For the proposed Refused Access Reconnection charge, please provide a detailed demonstration

of the calculation for each of the following cost inputs:

- ABSBC (Call Centre and Credit Review)
- Manual Disconnection
- Manual Reconnection

124.2.1 Please identify the changes in the methodology used to calculate the proposed Refused Access Reconnection Charge as compared to the methodology used to calculate the charge put forward in the 2007 BC Hydro RDA.

125.0 Reference: Exhibit B-1, Section 8.3.3, Table 8-4, p. 8-12; Appendix C-3A, pp. 93-94
Late Payment Charge - $30 Threshold

In Table 8-4 on page 8-12 of the Application, BC Hydro provides a jurisdictional comparison of other Canadian electric utilities' late payment charges.

125.1 Please indicate whether any of these Canadian electric utilities also have a threshold for application of the Late Payment Charge, and if so, what the threshold is for each utility.

On page 94 of Appendix C-3A, BC Hydro states: "The expected revenue impact of assessing a late payment charge for accounts with less than $30 owing is estimated to be less than $100,000 per year (the late payment charge revenue is estimated to be $7.5 million for F2015)."

125.2 Please provide a detailed calculation of the $100,000 revenue impact and explain all inputs and assumptions.

125.3 Please provide a detailed calculation of the additional cost to BC Hydro of assessing a late payment charge for accounts below the $30 threshold. Please explain all inputs and assumptions.

BC Hydro states on page 93 of Appendix C-3A that it "undertook a high-level analysis of its accounts receivable reporting for outstanding balances of less than $30 that are overdue between 30 and 60 days."

125.4 Please provide the percentage of total late payments that were less than the $30 threshold during F2015.

126.0 Reference: Exhibit B-1: Section 8.3.3, Tables 8-4 and 8-5, pp. 8-11 to 8-14
Late Payment Charge

In Table 8-4 on page 8-12 of the Application, BC Hydro provides a jurisdictional comparison of other Canadian electric utilities' late payment charges.

In Table 8-5 on page 8-13 of the Application, BC Hydro provides the cost breakdown for the 1.5 percent Late Payment Charge, which includes $1,968,415 of BC Hydro interest at its most recent Weighted Average Cost of Debt (WACD).

126.1 Please provide the type of carrying charge applied to late payment charges by each of the utilities listed in Table 8-4 (i.e. short-term interest rate, WACD, or other).

126.2 Please explain the rationale for applying WACD to late payment charges as opposed to short-term interest.

126.2.1 Which type of carrying charge does BC Hydro view as more reflective of how it finances costs related to late payment charges? Please discuss.

BC Hydro provides a breakdown of the Late Payment Charge costs in Table 8-5.

126.3 Please provide a more detailed breakdown and description of the Customer Late Payment Communications cost of $1,949,170, including how much of this cost is related to labour versus non-labour.

126.3.1 For the labour component of the cost, please describe the inputs comprising the cost, including number of labour hours and cost per labour hour.

126.4 Please provide a more detailed breakdown and description of the $250,000 O&M costs.

127.0 Reference: Exhibit B-1, Section 8.3.4, pp. 8-14 and 8-15; Appendix G-1B, p. 9
Returned Payment Charge

Page 9 of Appendix G-1B shows the calculation of the Returned Payment Charge, including the total number of returned payments of 11,892.

127.1 Please compare the total number of returned payments in F2015 to the total number of returned payments in F2006 (i.e. at the time of filing BC Hydro's 2007 RDA). Please also indicate how many of these returned payments in F2006 were returned cheques and how many were returned EFTs.

127.2 Please provide the fee charged by BC Hydro's bank for failed electronic payments as compared to failed cheques.

127.3 Please provide the supporting calculations and explain all inputs and assumptions for each of the following charges comprising the Returned Payment charge:

- BMO and Symcor Charges - $1.37;
- ABSBC Handling Cost - $3.68; and
- Customer Communication (Letter) - $1.00

127.4 What is the revenue impact of decreasing the Returned Payment Charge from the current charge of $20 to the proposed charge of $6? Please show all supporting calculations and explain all assumptions.

127.5 Please confirm, or explain otherwise, that if BC Hydro continued to use the NSF charge as a proxy for the Returned Payment Charge that it would be recovering an amount from customers that is higher than BC Hydro's actual costs related to this charge.

128.0 Reference: Exhibit B-1: Section 8.3.5, pp. 8-15 and 8-16; Appendix C-3A, pp. 97 to98; Appendix G-1B, p. 8
Account Charge

On page 8 of Appendix G-1B, BC Hydro provides the following information for the Account Charge:

- Total costs of setting up new accounts - $3,833,057
- Total cost of setting up new account per customer - $12.55

128.1 Please confirm, or explain otherwise, that the $12.55 cost provided in the preamble above includes both the cost of setting up a new account as well as the cost for an existing customer to move an account.

BC Hydro states the following on pages 8-15 and 8-16 of the Application:

> Costs have increased since the 2007 RDA because of general increases in labour charges as the result of inflation and by the introduction and use of Identity Validation software for new accounts to mitigate bad debt costs resulting from accounts being created in fraudulent names. However, the increase has been mostly offset by a shift towards applications being received through lower-cost online tools. [emphasis added]

BC Hydro states on page 8-16 of the Application:

> In Workshop 3, BC Hydro requested feedback on the potential to utilize a differentiated charge on the basis of the application being processed online versus agent, as well as a new customer account versus a move of an existing customer…BC Hydro is not proposing these differentiated charges. Instead, BC Hydro proposes to continue the existing method for determining the Account Charge.

BC Hydro further states in section 1.4.2 of the Workshop 3 consideration memo:

> The online service is fairly new and some customers may be disadvantaged by not having internet access…Based on initial analysis, BC Hydro estimates a savings of $300,000 with online move processing. These and additional savings from increased use of self-service options will be reflected in the analysis of moving and account set-up costs.

128.2 Based on the above preambles, is it fair to conclude that the largest driver of increased costs is due to new customer accounts as opposed to the moving of existing customer accounts? Please discuss.

128.3 Based on the above preambles, is it also fair to conclude that the largest driver of cost savings is due to online processing of applications from existing customers who are moving accounts? Please discuss.

128.4 If BC Hydro utilized a differentiated charge on the basis of new customer accounts versus the moving of existing customers' accounts, what would the differentiated charges be? Please provide all supporting calculations for these charges and explain all assumptions made.

128.5 If BC Hydro utilized a differentiated charge on the basis of the application being processed online versus through an agent, what would the differentiated charges be? Please provide all

supporting calculations for these charges and explain all assumptions made.

128.6 Please explain why it is fair to charge existing customers who move accounts the same amount as new customers. Please incorporate a discussion of the Bonbright principles as part of the explanation.

128.7 Please compare the F2015 fees paid to Equifax for credit checks and ID validation of $442,804 (Appendix G-1B, page 8) to the F2006 Equifax fees provided in the BCH 2007 RDA. Please explain the causes/drivers of the increased fees.

128.7.1 What costs are included in the $442,804? Is this a flat fee charged by Equifax? Please explain.

128.8 Are the Equifax costs of $442,804 mainly attributable to new customer accounts? Please explain.

128.9 Please provide a more detailed explanation and breakdown of the $3,390,253 "ABSBC costs related to processing application for service."

128.9.1 Please confirm, or explain otherwise, that the $300,000 estimated cost savings from online processing has been reflected in the "ABSBC costs related to processing application for service" of $3,390,253.

128.10 Of the 305,522 applications for service in F2015, how many of these were for new customer accounts as opposed to existing customers moving accounts?

129.0 Reference: Exhibit B-1, Section 8.3.6, pp. 8-16 and 8-17
Proposed Meter Test charge

On page 8-17 of its Application, BC Hydro identifies 3 options for the Meter Test charge:

- Option 1 – the updated default Minimum Reconnection Charge 1 of $30;
- Option 2 – the updated Minimum Connection Charge (First Meter) of $181 to more closely reflect cost recovery; and
- Option 3 – the current (not updated) default Minimum Reconnection Charge of $125.

With respect to the options for the proposed Meter Test charge, BC Hydro submits on page 8-17 of its Application that "COPE 378 expressed concern that both option 2 and option 3 may result in some customers with legitimate concerns foregoing their right to have the meter tested out of concern they would be charged if the meter passes."

BC Hydro further submits on page 8-17 of the Application that it "agrees with BCOAPO and FNEMC that option 2 is preferable because it provides full cost recovery."

129.1 What is BC Hydro's response COPE 378's concern discussed on page 8-17 of the Application? Please discuss.

129.2 How often are meters tested as part of Measurement Canada regulations, other legislation or regulation, or internal BC Hydro policy? What is the normal rotation of meters for testing?

129.3 In the event that Option 1 or Option 3 become the Meter Test Charge, please identify the revenue shortfall that would be required to be absorbed by BC Hydro's other ratepayers and the rate impact.

129.4 Please provide the total cost incurred by BC Hydro for F2015 related to sending customers' meters to Measurement Canada for testing. Please show all calculations.

130.0 Reference: Exhibit B-1, Appendix G-1B, p. 6
Proposed Meter Test Charge – vehicle costs

The calculation for the proposed Meter Test Charge of $181 is included in Appendix G-1B, page 6. It includes vehicle costs determined as 29 percent of the labour required.

130.1 Please explain the rationale for using a percentage of labour required to determine the vehicle costs, as opposed to vehicle hourly rate.

130.2 Please provide supporting calculations for the unloaded labour cost and crew cost.

130.3 With respect to the costs incurred for the meter test, please provide the following:

- vehicle type used;
- hourly rate for vehicle type used; and
- calculation of vehicle cost input to the Meter Test Charge using the hourly rate for the vehicle type used.

131.0 Reference: Exhibit B-1, Appendix G-1B, p. 6
Proposed Meter Test Charge – total labour

The Meter Test Charge "Basis for Calculation" schedule found in Appendix G-1B of the BC Hydro Application includes a loaded SLR of $143.57.

131.1 Is a powerline technician required for the removal of the meter in order to facilitate a meter test? Please discuss why or why not.

131.1.1 If the answer to the aforementioned IR is no, please provide the appropriate employee type required and the related loaded SLR.

132.0 Reference: Exhibit B-1, Appendix G-1B, p. 6
Proposed Meter Test Charge – other charges

132.1 Does BC Hydro incur any additional costs in order to have a meter tested by Measurement Canada, other than those outlined in Appendix G-1B, page 6? Specifically, charges from Measurement Canada, customer service costs or other costs subsequent to the meter test? If yes, please provide the weighted average cost per meter for each type of additional cost, with a demonstration of the cost calculation.

132.2 What is the revenue requirement impact of excluding these costs from the proposed Meter Test Charge and the resulting rate impact?

133.0 Reference: Exhibit B-1, Section 8.3.7.1, pp. 8-17 and 8-18
Collection charge

BC Hydro states on page 8-17 of the Application that the Collection Charge is no longer relevant because:

(i) RDR capability from smart meters means most disconnections are performed without the need to dispatch a crew; and
(ii) Crews are no longer permitted to accept payments for safety and security reasons.

133.1 For F2015, what percentage of disconnections required a crew to be dispatched?

133.2 Did BC Hydro encounter any situations in F2015 where crews were dispatched to perform a disconnection but did not follow through with the disconnection due to a customer indicating his/her intent to make payment?

133.2.1 If yes, or if there are other scenarios where a disconnection was not completed by a dispatch crew, how does BC Hydro propose to recover these costs in lieu of the Collection Charge?

133.3 If the Collection Charge was not eliminated, what amount would BC Hydro propose for this charge? Please explain the rationale for this amount.

134.0 Reference: Exhibit B-1, Section 8.3.7.2, p. 8-18
DataPlus Service

BC Hydro states on page 8-18 of the Application that the current DataPlus Service Charge is $360 per year per Collective Master Account.

134.1 How much revenue was collected from the DataPlus Service Charge for F2015?

134.2 What was the total cost and the per customer cost for BC Hydro to provide the DataPlus Service in F2015? Please provide all calculations and explain any assumptions.

BC Hydro states on page 8-18 of the Application:

> …an IT project is currently underway to address gaps in data and usability for some of the largest commercial customers. The DataPlus Service would be discontinued once the project is complete (tentatively mid-2016) and existing customers have been transitioned to the new self-service tool.

134.3 Please describe the IT project referenced in the above preamble.

134.4 What is the forecast total cost of this IT project?

134.4.1 How does BC Hydro propose to recover the cost of this IT project?

134.5 Does BC Hydro anticipate that there will be ongoing administrative or other costs related to this project once it is complete and the existing DataPlus Service customers are transitioned to the new self-service tools?

134.5.1 If no, please explain why not.

134.5.2 If yes, please discuss if these ongoing costs should be recovered from the DataPlus Service customers through a revised charge.

134.6 What is the likelihood that completion of the IT project could be delayed to the end of 2016 or later? Please discuss.

134.7 What steps is BC Hydro taking to ensure that the new self-service tools will meet the needs of the DataPlus service customers? Please discuss.

135.0 Reference: Exhibit B-1, Section 8.4, pp. 8-19 to 8-22
Security Deposit

135.1 Does BC Hydro anticipate that creating increased flexibility for the application of security deposits will result in increased administration costs? Please discuss.

135.2 Has BC Hydro experienced an increase in bad debt write-offs since the 2007 RDA was filed? If yes, please provide the approximate percentage increase in bad debt write-offs.

135.3 What is BC Hydro's average annual bad debt write-off? Please compare this amount to the three largest bad debt write-offs experienced in F2015.

BC Hydro states on page 8-21 of the Application that its proposal benefits itself and customers in part because "collection processes can be modified to enable a progressive increase in the security deposit applied in situations warranted by the level of risk posed by the customers."

135.4 Please provide a more detailed explanation of how BC Hydro would determine the appropriate security deposit amount for different customers under the proposed new wording.

135.5 Given the increased flexibility the proposed wording provides as to the amount of security deposit charged to different customers, please discuss if the changes could cause the following: (i) a decreased customer understanding of how and when a security deposit is calculated/required; and (ii) a perceived lack of fairness amongst customers.

135.6 Please provide a more detailed explanation of how BC Hydro would calculate standardized security deposit amounts.

135.6.1 Please also explain which types of customers BC Hydro views as being potential candidates for standardized security deposits and why.

136.0 Reference: Exhibit B-1, Section 8.6, pp. 8-22 to 8-35
Potential low income customer terms and conditions

BC Hydro states as part of its comments in Table 8-6 (page 8-24) of the Application: "An income-based waiver [of a security deposit] would require a process to verify income and will have administrative costs."

136.1 Has BC Hydro explored the possibility of the Ministry of Social Development and Social Innovations undertaking the income verification process?

136.1.1 If yes, would this eliminate the additional administrative costs to BC Hydro of providing an income-based waiver? If not, please explain why not.

On page 8-29 of the Application, BC Hydro describes the jurisdictional review it conducted of Canadian and US electric utilities.

136.2 Please explain why BC Hydro did not include gas utilities as part of its jurisdictional review.

1.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 1.1.3 Orders Sought, pp. 1-5 and 1-11
BC Hydro seeking interim rate orders

On page 1-5, BC Hydro says it will seek interim rate orders, to be effective April 1, 2016, when filing the F2017 revenue requirement application (RRA) in late February 2016 and that its request will include an interim order increasing the RIB rate pricing elements in accordance with the requested RIB Pricing-Principles. On page 1-11, BC Hydro says that it would be requesting an interim rate order for the rate schedule (RS) 1823 F2017-F2019 pricing principles. No such requests for the medium general service (MGS) and large general service (LGS) are noted by Commission staff given that BC Hydro is proposing a flat energy charge for these rates.

1.1.1 Given the critical importance of pricing principles in the design of conservation rate structures and the overall intent of the rate structures to encourage conservation, would the two interim rate order requests that combine RRA rate increase and rate design pricing principles create customer confusion by distorting the price signals of the conservation rate structures? Please describe the benefits and disbenefits perceived by BC Hydro in requesting these interim rate orders.

RESPONSE:

BC Hydro is requesting the two interim rate orders because the current RIB pricing principles and the current RS 1823 pricing principles expire on March 31, 2016. In the absence of the two interim rate orders, BC Hydro would not have any pricing principles to establish new RIB and RS 1823 rates effective April 1, 2016. BC Hydro did not request an interim order for the new MGS and LGS rates since the requested effective date is April 1, 2017 and the Commission decision is expected well before that date.

BC Hydro is of the view that the two interim orders will not create customer confusion with respect to the design of the rate structures. The RIB and RS 1823 rate structures are well established and understood by customers and will not change significantly after the F2017 RRA increases are applied.

2.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.2, pp. 2-6 and 2-14
Legal regime

On page 2-6 BC Hydro says: "The net result in BC Hydro's view is that the Commission may, but is not obliged to, consider and be guided by the British Columbia's energy objectives, subject to the proviso that in the event of a conflict between an energy objective and a rate-setting provision of the [*Utilities Commission Act* (UCA)], the latter must prevail."

On page 2-14, BC Hydro says:
At Workshop 8a, BC Hydro set out its position that Policy Action No. 4 of the 2007 Energy Plan does not oblige the Commission to ignore the eight Bonbright rate design criteria in favour of a conservation objective or to prioritize the Bonbright efficiency criterion over the other seven criteria. BC Hydro implemented an inclining block rate for its Residential customers in October 2008 (the RIB rate; refer to section 2.3.1.6 below). BC Hydro also explored the possibility of inclining block rates for its General Service customers, but as noted in Chapter 6 of the Application, BC Hydro concludes such rate structures are not viable given the heterogeneous nature of each of the SGS, MGS and LGS rate classes. BC Hydro also explored optional interruptible rates and what is referred to as an optional 'Efficiency Rate Credit' for General Service customers, and an optional clean energy credit for its Residential customers. As described in section 1.5.2 of the Application, BC Hydro will address optional rates for General Service and Residential customers as part of 2015 [Rate Design Application (RDA)] Module 2.

1.2.1 Please identify any of the energy objectives in the *Clean Energy Act* that are in conflict with BC Hydro's rate design proposal.

RESPONSE:

In BC Hydro's view, none of the rate design proposals contained in 2015 RDA Module 1 conflict with the section 2 *CEA* British Columbia's energy objectives:

- **Pursuant to section 3(1) of the *CEA*, the 2013 IRP is the vehicle through which BC Hydro provides a description of how it plans to achieve self-sufficiency and respond to the other 15 British Columbia's energy objectives. Some of the 2015 RDA rate design proposals are expressly contemplated in the 2013 IRP, including continuing with the RIB rate as the default residential rate (2013 IRP, section 9.2.1.3) and investigating customer incentive mechanisms such as the freshet rate pilot (2013 IRP, section 9.2.5); and**

- **BC Hydro does not view the *CEA* British Columbia's energy objectives as the main source for determining B.C. Government policy as it pertains to the 2015 RDA. Please refer to BC Hydro's response to BCUC IR 1.2.2.**

2.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.2, pp. 2-6 and 2-14
Legal regime

On page 2-6 BC Hydro says: "The net result in BC Hydro's view is that the Commission may, but is not obliged to, consider and be guided by the British Columbia's energy objectives, subject to the proviso that in the event of a conflict between an energy objective and a rate-setting provision of the [*Utilities Commission Act* (UCA)], the latter must prevail."

On page 2-14, BC Hydro says:
At Workshop 8a, BC Hydro set out its position that Policy Action No. 4 of the 2007 Energy Plan does not oblige the Commission to ignore the eight Bonbright rate design criteria in favour of a conservation objective or to prioritize the Bonbright efficiency criterion over the other seven criteria. BC Hydro implemented an inclining block rate for its Residential customers in October 2008 (the RIB rate; refer to section 2.3.1.6 below). BC Hydro also explored the possibility of inclining block rates for its General Service customers, but as noted in Chapter 6 of the Application, BC Hydro concludes such rate structures are not viable given the heterogeneous nature of each of the SGS, MGS and LGS rate classes. BC Hydro also explored optional interruptible rates and what is referred to as an optional 'Efficiency Rate Credit' for General Service customers, and an optional clean energy credit for its Residential customers. As described in section 1.5.2 of the Application, BC Hydro will address optional rates for General Service and Residential customers as part of 2015 [Rate Design Application (RDA)] Module 2.

1.2.2 While BC Hydro argues that the Commission is not obligated to be guided by the BC government energy objectives, would BC Hydro agree that the Commission should consider and give significant weight to those energy objectives? Why or why not?

RESPONSE:

The Commission is not legally obligated to consider the *CEA* British Columbia's energy objectives in exercising its rate setting powers pursuant to sections 58 to 61 of the *UCA*. This is in contrast to the Commission's obligation to consider[1] the British Columbia's energy objectives in exercising its powers with respect to acceptance of BC Hydro expenditure schedules pursuant to subsection 44.2(5.1) of the *UCA*; issuing CPCNs to BC Hydro pursuant to subsection 46(3.3) of the *UCA*; and in determining, after a hearing, whether an EPA is in the public interest under subsection 71(2.21) of the *UCA*.

[1] Section 22 of the *Miscellaneous Statutes Amendment Act (No. 3), 2015*, S.B.C. 2015, c.42 (Royal Assent on November 17, 2015), amends sections 44.2(5.1), 46(3.3) and 71 (2.21) and (2.51) of the *UCA* by striking out "and be guided by".

BC Hydro recognizes that the Commission has examined the *CEA* British Columbia's energy objectives as part of B.C. Government policy in the rate setting context; refer to *In the Matter of FortisBC Inc.: Application for Approval of Stepped and Stand-by Rates for Transmission [Voltage] Customers,* Decision, May 26, 2014, page 44; and *In the Matter of FortisBC Inc.: Application for Approval of Stepped and Stand-by Rates for Transmission [Voltage] Customers*, Decision, Stage IV, September 22, 2015, page 9.

BC Hydro agrees that the Commission should consider and give significant weight to B.C. Government policy as part of its adjudication of the 2015 RDA. However, BC Hydro does not view the *CEA* British Columbia's energy objectives as the main source for determining B.C. Government policy as it pertains to the 2015 RDA. Rather, B.C. Government policy as it pertains to the 2015 RDA is set out in section 2.2.2 of Exhibit B-1, including the B.C. Ministry of Energy and Mines letter dated September 17, 2015 found at Appendix C-1C of Exhibit B-1. BC Hydro will make its submission concerning the weight the Commission ought to place on the *CEA* British Columbia's energy objectives as part of the argument phase of the 2015 RDA regulatory review.

2.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.2, pp. 2-6 and 2-14
Legal regime

On page 2-6 BC Hydro says: "The net result in BC Hydro's view is that the Commission may, but is not obliged to, consider and be guided by the British Columbia's energy objectives, subject to the proviso that in the event of a conflict between an energy objective and a rate-setting provision of the [*Utilities Commission Act* (UCA)], the latter must prevail."

On page 2-14, BC Hydro says:
At Workshop 8a, BC Hydro set out its position that Policy Action No. 4 of the 2007 Energy Plan does not oblige the Commission to ignore the eight Bonbright rate design criteria in favour of a conservation objective or to prioritize the Bonbright efficiency criterion over the other seven criteria. BC Hydro implemented an inclining block rate for its Residential customers in October 2008 (the RIB rate; refer to section 2.3.1.6 below). BC Hydro also explored the possibility of inclining block rates for its General Service customers, but as noted in Chapter 6 of the Application, BC Hydro concludes such rate structures are not viable given the heterogeneous nature of each of the SGS, MGS and LGS rate classes. BC Hydro also explored optional interruptible rates and what is referred to as an optional 'Efficiency Rate Credit' for General Service customers, and an optional clean energy credit for its Residential customers. As described in section 1.5.2 of the Application, BC Hydro will address optional rates for General Service and Residential customers as part of 2015 [Rate Design Application (RDA)] Module 2.

1.2.3 Are there any government energy objectives that are in conflict with the eight Bonbright criteria? If so, how should the Commission weigh the competing objectives and criteria? Why?

RESPONSE:

In BC Hydro's view, the section 2 *CEA* British Columbia's energy objectives do not conflict with the eight Bonbright rate design criteria:

- **The British Columbia's energy objectives and Bonbright rate design criteria address different initiatives. As described in BC Hydro's response to BCUC IRs 1.2.1 and 1.2.2, the *CEA* and *UCA* provide that the British Columbia's energy objectives are to be responded to by BC Hydro in its IRPs, and to be considered by the Commission when adjudicating acceptance of BC Hydro expenditure schedules pursuant to subsection 44.2(5.1) of the *UCA*; issuing CPCNs to BC Hydro pursuant to subsection 46(3.3) of the *UCA*; and in determining, after a hearing, whether an EPA is in the public interest under subsection 71(2.21) of the *UCA.* Accordingly, the *CEA* and *UCA* schemes do not contemplate the British**

Columbia's energy objectives as rate setting criteria. In contrast, the Bonbright criteria are rate design criteria;

- **The British Columbia's energy objectives do not require the Commission to prioritize one or some of the Bonbright rate design objectives; and**

- **There is little overlap between the British Columbia's energy objectives and Bonbright rate design criteria. There is potential overlap with respect to economic development (*CEA* section 2(k)). BC Hydro accepts that many stakeholders and customers view the Bonbright customer understand and acceptance criterion as encompassing customer views on whether a rate structure advances or hinders economic development. This was particularly evident with respect to customer comments concerning the existing MGS and LGS rate structures, with some customers conveying to BC Hydro through the various 2015 RDA stakeholder engagement streams that these rates hinder economic development due to, among other things, their complexity. While BC Hydro does not directly rely on economic development as a criteria for any of its 2015 RDA rate design proposals, BC Hydro considers that its MGS and LGS proposals, which simplify the existing rates, facilitates customer understanding and acceptance.**

2.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.2, pp. 2-6 and 2-14
Legal regime

On page 2-6 BC Hydro says: "The net result in BC Hydro's view is that the Commission may, but is not obliged to, consider and be guided by the British Columbia's energy objectives, subject to the proviso that in the event of a conflict between an energy objective and a rate-setting provision of the [*Utilities Commission Act* (UCA)], the latter must prevail."

On page 2-14, BC Hydro says:
At Workshop 8a, BC Hydro set out its position that Policy Action No. 4 of the 2007 Energy Plan does not oblige the Commission to ignore the eight Bonbright rate design criteria in favour of a conservation objective or to prioritize the Bonbright efficiency criterion over the other seven criteria. BC Hydro implemented an inclining block rate for its Residential customers in October 2008 (the RIB rate; refer to section 2.3.1.6 below). BC Hydro also explored the possibility of inclining block rates for its General Service customers, but as noted in Chapter 6 of the Application, BC Hydro concludes such rate structures are not viable given the heterogeneous nature of each of the SGS, MGS and LGS rate classes. BC Hydro also explored optional interruptible rates and what is referred to as an optional 'Efficiency Rate Credit' for General Service customers, and an optional clean energy credit for its Residential customers. As described in section 1.5.2 of the Application, BC Hydro will address optional rates for General Service and Residential customers as part of 2015 [Rate Design Application (RDA)] Module 2.

1.2.4 With respect to a possible General Service class "efficiency rate credit" to be considered in module 2, what impact would such an incentive have in support of BC Hydro's proposed flat energy and flat demand charges for MGS and LGS customers? For example, if the efficiency rate credit were to incent efficiency and conservation, one might expect that to provide added support for the flat rate proposals since the "efficiency rate credit" might satisfy the efficiency and conservation concerns.

RESPONSE:

BC Hydro cannot at this time speculate on the impact of an "efficiency rate credit" in combination with BC Hydro's proposed flat energy and flat demand charges for the MGS and LGS classes. As discussed during RDA Workshop 11B, an efficiency rate credit has been postulated for the purpose to enable delivery of appropriate price signals for conservation and efficiency. BC Hydro, through the Electricity

Conservation and Efficiency Advisory Committee is examining efficiency ratings and standards as well as potential infrastructure required to implement them. This work must be undertaken first before consideration can be given to whether an efficiency rate credit can be designed to link to these ratings. Thus, BC Hydro is unable to assess the efficiency rate credit concept at time, but proposes to review in RDA Module 2, after LGS and MGS default rates have been set by the Commission.

3.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.2.2.1 Postage Stamp Rates, pp. 2-9 and 2-10
Postage stamp rates

On page 2-9, BC Hydro says that postage stamp rates are a method of cost allocation and that the underlying premise is that all customers jointly develop electricity resources and should equally share in the costs. It further describes the postage stamp rate as a fundamental BC government rate design policy, subject only to two discrete and generally accepted exceptions such as limits on the cost of new extensions and Zone II rate design.

1.3.1 Is it more accurate to describe postage stamp rates as a method of revenue collection as opposed to cost allocation?

RESPONSE:

Postage stamp rates can accurately be described as a method of revenue collection that is supported by a specific method of cost allocation.

3.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.2.2.1 Postage Stamp Rates, pp. 2-9 and 2-10
Postage stamp rates

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1.3.2 On page 1-11, BC Hydro requests a final order approving a revision, among other things, to the definition of High Load Hours (HLH) to provide BC Hydro discretion to determine the HLH periods that will apply based on a customer location/region which affords BC Hydro the possibility to curtail. Is this another exception to the postage stamp rates?

RESPONSE:

No, BC Hydro's proposed revision to RS 1852 does not result in an exception to postage stamp rates. The proposed revision to the RS 1852 definition of HLH broadens the availability of RS 1852.This is because prior to the proposed revision, RS 1852 was effectively limited to Vancouver Island given the definition of HLH (refer to the Workshop 10 consideration memo, Exhibit B-1 Appendix C-5B page 103 of 212).

Postage stamp rates allow for the standardization of rates across a utility's service area regardless of the differences in the cost to serve individual geographical areas. The principle of postage stamp rates applies to default rates and not to voluntary optional rates such as RS 1852.

3.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.2.2.1 Postage Stamp Rates, pp. 2-9 and 2-10
Postage stamp rates

On page 2-9, BC Hydro says that postage stamp rates are a method of cost allocation and that the underlying premise is that all customers jointly develop electricity resources and should equally share in the costs. It further describes the postage stamp rate as a fundamental BC government rate design policy, subject only to two discrete and generally accepted exceptions such as limits on the cost of new extensions and Zone II rate design.

1.3.3 Is RS 1852 (Modified Demand Transmission) an exception to the postage stamp rate because its availability is location specific?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.3.2.

4.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.2.3.3, Customer focus groups, pp. 2-23, and 2-25
Bill understanding

On page 2-23 BC Hydro states that: "…most (residential) participants were aware of the total amount of their electricity bills as opposed to the RIB rate structure; and most participants reject a three step rate as too complicated." And on page 2-25 BC Hydro states: "Most (LGS/MGS) customers reportedly look at their electricity bills, but this is mainly in regards to total dollar amount."

1.4.1 Given BC Hydro's preferred rate structure for the Residential class is the status quo, what further actions can BC Hydro take under the status quo scenario to improve customers' understanding of their bills to promote the rate design objectives of efficiency and conservation? Are there any promotional materials being contemplated?

RESPONSE:

As noted in BC Hydro's response to BCUC IR 1.38.2, BC Hydro is of the view that 50 per cent awareness of the RIB rate is reasonable given past outreach efforts and the period of time the RIB rate has been in effect. Accordingly, at this time, BC Hydro does not have plans to initiate a marketing campaign specifically intended to raise awareness and understanding of the RIB rate.

Due to the large number of accounts, producing print materials for marketing campaigns is costly. For example:

- **At $0.89 per letter, sending one direct mail to 1.7 million residential accounts would cost $1.5 million; and**
- **At $0.15 per customer for printing and bill stuffing, one bill insert to 63 per cent of the 1.7 million residential accounts receiving paper bills would cost $0.2 million.**

BC Hydro is evaluating a Customer Billing Project, which aims to redesign BC Hydro's bills to increase customers' understanding of their bills and rates, deliver clearer account related information and promote conservation messages. If approved, this project would potentially be in place in 2017. Please also refer to BC Hydro's response to COPE IR 1.20.1.

5.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.3.1.4; 2005 Transmission Service Rate Application, p. 2-36, Footnote 74
Commission jurisdiction to review exempt customers

Footnote 74 on page 2-36 indicates that the exemption customers from the transmission stepped rate originally extended to Aquila, now FortisBC Inc. In May 2013, BC Hydro applied to the Commission to replace the Power Purchase Agreement with FortisBC Inc. under RS 3808.

1.5.1 Given BC Hydro's comment on page 2-16 that the Commission can only be given jurisdiction to review and make recommendations concerning exempt entities through a section 5 UCA inquiry review process and only the Lieutenant Governor in Council can refer this matter to the Commission under section 5 of the UCA, please provide a brief history of how FortisBC Inc. became separated from the exempt group.

RESPONSE:

For purposes of the Commission's adherence to subsection 3(1) of Direction No. 7, FortisBC has not been separated from New Westminster or UBC, the two RS 1827 customers that together with FortisBC are referenced in Heritage Contract Report Recommendation No. 15 dated October 17, 2003. The Commission cannot unilaterally transfer FortisBC, New Westminster or UBC to RS 1823 or set a stepped rate for FortisBC, New Westminster or UBC similar to RS 1823. RS 3808 has a two-tranche pricing structure for energy, but otherwise has little in common with RS 1823.

History

BC Hydro sought approval for RS 1827 for both UBC and New Westminster in the TSR Application (March 2005). BC Hydro also proposed in its Application that FortisBC remain on RS 3808, which at that time had energy and demand rates the same as RS 1821. The Application was resolved through a NSP and approved by Commission Order No. G-79-05.

BC Hydro has served FortisBC pursuant to RS 3808 and a PPA since at least 1993. The former PPA was set to expire in 2013. BC Hydro and FortisBC negotiated a new PPA and new RS 3808 to replace the expiring rate, and these were filed with the Commission for approval in May 2013. In its proceeding to review the new RS 3808 and new PPA, the Commission explored the differences between the new RS 3808 and RS 1823. The Commission approved the current RS 3808 and PPA by Commission Order No. G-60-14 dated May 6, 2014.

6.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Sections 1.5 and 2.4, Rate Assessment Methodology, pp. 1-20, 2-37, 2-56 – 2-57 and 2-61
Bonbright criteria weighting

Tables 1.2 and 2.7 provide Bonbright rate design criteria and BC Hydro's application of the criteria. "In section 1.5.1 of the Application, BC Hydro set out that it prioritizes the Bonbright customer understanding and acceptance, stable rates for customers, and fair apportionment of costs among customers criteria for purposes of 2015 RDA Module 1."

On page 2-37 BC Hydro states that: "The 2007 RDA was BC Hydro's first comprehensive RDA since 1991."

1.6.1 How have BC Hydro's experiences since 2007 modified its interpretation and priorities of the eight Bonbright rate design criteria on Table 2.7? For example, natural gas prices, electricity market prices and differentials, self-sufficiency, reduced Long-Run Marginal Cost (LRMC), and government policy.

RESPONSE:

BC Hydro's experiences since 2007 have not caused it to modify its interpretation of the eight Bonbright criteria; however, BC Hydro's experiences, including its environment, since 2007 have caused it to modify its prioritization of the eight Bonbright criteria. Prioritization of Bonbright criteria should reflect the utility's situation at the time of the particular rate design initiative, and accordingly prioritization can be expected to change over time.

In the 2007 RDA, BC Hydro prioritized the Bonbright customer understanding and acceptance (simplicity), fair apportionment of cost among customers and efficiency criteria. As noted in sections 1.1.1 and 1.5.1 of Exhibit B-1, for purposes of 2015 RDA Module 1 BC Hydro prioritizes the three Bonbright customer understanding and acceptance, stable rates for customers, and fair apportionment of cost among customers criteria.

A number of factors underpin the 2015 RDA prioritization:

- **Reduced Forecasted Need/Self-Sufficiency - As summarized between page 1-2, line 18 to page 1-3, line 3 of Exhibit B-1, a number of elements such as a change to the self-sufficiency regulatory regime led to a reduced forecasted energy and capacity need since 2007. This resulted in a lower energy LRMC as compared to 2007. The reduced need for energy and**

capacity is one of the factors leading BC Hydro to prioritize customer understanding and acceptance and stable rates for customers over the Bonbright efficiency criterion. The reduced forecasted energy and capacity need enabled BC Hydro to take stock of existing rates introduced to achieve energy conservation since 2007 (RIB rate, MGS two-part baseline rate, LGS two-part baseline rate) and to prioritize minimizing unexpected changes by proposing replacement or amendment of only those rates that clearly do not the meet customer understanding and acceptance criterion such as the LGS and MGS rates;

- **Reduced LRMC – The reduced LRMC as compared to 2007 did not cause BC Hydro to modify its prioritization of the eight Bonbright criteria. The reduced LRMC is relevant for the pricing principle options for both the RIB rate and RS 1823, and to apply the Bonbright efficiency criterion to rate structure alternatives;**

- **Government Policy – Policy Action 4 of the 2007 Energy Plan called on BC Hydro to explore new rate structures that encourage energy conservation; this BC Hydro did between 2008 (RIB rate introduction) and 2010 (MGS/LGS two-part baseline rate introduction). Recent B.C. Government initiatives conveyed a focus on rate impacts such as the Direction No. 7 rate caps and the Government's response to the 2013 IEPR task force, and this also led BC Hydro to prioritize customer understanding and acceptance (bill impacts); and**

- **Changing Customer Expectations/Stakeholder Engagement – While not noted in the IR, other factors leading BC Hydro to prioritize customer understanding and acceptance is increased customer expectations and the 2015 stakeholder engagement, both with respect to BC Hydro's prioritization of the Bonbright criteria (refer to Exhibit B-1, section 2.4.1.2) and to individual rate structures such as the LGS and MGS rates.**

Forecasted natural gas prices and spot market prices have declined since 2007. BC Hydro viewed forecasted spot market prices as relevant to non-firm (interruptible) rates. Spot market forecasts were explored in the 2015 RDA stakeholder engagement process for purposes of non-firm rate pricing; see for example, the freshet rate pilot proposal energy charge determination at pages 7-37 and 7-38 of Exhibit B-1.

6.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Sections 1.5 and 2.4, Rate Assessment Methodology, pp. 1-20, 2-37, 2-56 – 2-57 and 2-61
Bonbright criteria weighting

Tables 1.2 and 2.7 provide Bonbright rate design criteria and BC Hydro's application of the criteria. "In section 1.5.1 of the Application, BC Hydro set out that it prioritizes the Bonbright customer understanding and acceptance, stable rates for customers, and fair apportionment of costs among customers criteria for purposes of 2015 RDA Module 1."

On page 2-37 BC Hydro states that: "The 2007 RDA was BC Hydro's first comprehensive RDA since 1991."

1.6.2 BC Hydro notes that the eight Bonbright criteria presented in Table 2.7 are presented in no particular order. For Table 1.2, three of the Bonbright criteria are said to be "prioritized criteria." Please explain how Table 1-2 and Table 2-7 relate to each other.

RESPONSE:

Table 2-7, Exhibit B-1 is intended to identify and provide a high level summary of the eight Bonbright criteria and how BC Hydro applied the criteria to the evaluation of rate structures. Table 1-2 of Exhibit B-1 is a subset of the eight Bonbright criteria identified in Table 2-7, and identifies BC Hydro's prioritized Bonbright criteria given the five factors listed in section 1.1.1 of Exhibit B-1.

6.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Sections 1.5 and 2.4, Rate Assessment Methodology, pp. 1-20, 2-37, 2-56 – 2-57 and 2-61
Bonbright criteria weighting

Tables 1.2 and 2.7 provide Bonbright rate design criteria and BC Hydro's application of the criteria. "In section 1.5.1 of the Application, BC Hydro set out that it prioritizes the Bonbright customer understanding and acceptance, stable rates for customers, and fair apportionment of costs among customers criteria for purposes of 2015 RDA Module 1."

On page 2-37 BC Hydro states that: "The 2007 RDA was BC Hydro's first comprehensive RDA since 1991."

1.6.3 Have BC Hydro's experiences with the lack of conservation achieved under the MGS and LGS rate structures downgraded the efficient price signal rate design priority not only for the GS class but also for the Residential and Transmission classes? Please explain.

RESPONSE:

No. With respect to BC Hydro's overall Bonbright criterion prioritization, changes to the regulatory regime relating to self-sufficiency and lower customer demand have reduced the forecasted energy needs. As, such the need for energy has decreased. In this regard please refer to BC Hydro's response to BCUC IR 1.6.1.

When weighing the efficient price signal against other Bonbright criteria such as customer understanding and acceptance for purposes of assessing MGS and LGS rate alternatives, and taking into account stakeholder feedback, BC Hydro determined that for the MGS and LGS rate classes a flat rate structure was more appropriate, even if in the case of the LGS rate the energy rate is well below BC Hydro's LRMC.

When evaluating the RIB rate and RS 1823, BC Hydro determined that both of these rate structures are generally well understood and achieving conservation.

6.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Sections 1.5 and 2.4, Rate Assessment Methodology, pp. 1-20, 2-37, 2-56 – 2-57 and 2-61
Bonbright criteria weighting

Tables 1.2 and 2.7 provide Bonbright rate design criteria and BC Hydro's application of the criteria. "In section 1.5.1 of the Application, BC Hydro set out that it prioritizes the Bonbright customer understanding and acceptance, stable rates for customers, and fair apportionment of costs among customers criteria for purposes of 2015 RDA Module 1."

On page 2-37 BC Hydro states that: "The 2007 RDA was BC Hydro's first comprehensive RDA since 1991."

1.6.4 Is there value in prioritizing some Bonbright criteria over others in the context of the overall Rate Design Application? In other words, why would it not be more reasonable to consider that some Bonbright criteria might be more relevant than others when assessing a particular aspect of the Application, but that the most relevant criteria might change depending on the particular issue being reviewed? Please explain.

RESPONSE:

BC Hydro believes that there is value in prioritizing some Bonbright criteria over others in the context of the overall RDA. As discussed in section 1.5.1 of Exhibit B-1, BC Hydro's three prioritized criteria are informed by the five factors described in section 1.1.1 to reflect the current conditions in which BC Hydro is operating in. While the application of the Bonbright criteria may vary depending on the rate structure being examined (e.g., the application of the Bonbright efficiency criteria would be different in a transmission extension policy context as compared to a default rate structure context), where a tradeoff is required the weight should be given to the prioritized criteria described in Table 1-2 of Exhibit B-1.

7.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.3.1.5 2007 RDA, p. 2-39 10 Percent maximum bill impact threshold

On page 2-39, BC Hydro says that in the 2007 RDA, it was criticized for excluding RRA increases from the 10 percent maximum bill impact test, and in response, the 10 percent bill impact test used to develop the 2015 RDA is inclusive of RRA increases.

1.7.1 Does BC Hydro accept that customer response from general rate increases will, all things being equal, result in natural conservation whereas customer response from rate design changes such as stepped rate structure, all things being equal, will result in demand-side management (DSM) conservation savings? If yes, does including RRA increase when analyzing bill impact in a rate design study blur the definition of the two types of conservation savings?

RESPONSE:

As noted at Exhibit B-1, Appendix C-3B, page 372 of 609, footnote 14:

- **Natural conservation is conservation induced by general rate increases applied to rate classes through RRAs, absent any rate structure changes, and is not considered by BC Hydro to be DSM; and**

- **Rate structure conservation is the incremental conservation induced by changing the elements of the rate structure, and is considered by BC Hydro to be DSM.**

BC Hydro defines bill impact as the percentage change in a customer's annual bill from one year to the next if consumption stays the same (Exhibit B-1, page 2-58, lines 8-9). In BC Hydro's view, the inclusion of RRA increases as part of the 10 per cent maximum bill impact test has no bearing on the definition of these two types of conservation; whether the inclusion of RRA increases would use up room available to accommodate rate design-related bill impacts is not related to defining natural conservation and rate structure conservation.

7.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.3.1.5 2007 RDA, p. 2-39 10 Percent maximum bill impact threshold

On page 2-39, BC Hydro says that in the 2007 RDA, it was criticized for excluding RRA increases from the 10 percent maximum bill impact test, and in response, the 10 percent bill impact test used to develop the 2015 RDA is inclusive of RRA increases.

1.7.2 Please provide a table showing two columns of data, historical and projected, between F2006 to F2019: Column 1 showing annual RRA increases and Column 2 showing the room for rate design increases under the 10 percent bill impact threshold.

RESPONSE:

The requested table is provided below.

	Column 1 **Annual RRA Increase (%)**	**Column 2** **Room for Rate Design Increase (%)** **(10% - Annual RRA Increase %)**
F2006	**0.00**	**10.00**
F2007	**1.54**	**8.46**
F2008	**0.10**	**9.90**
F2009	**2.34**	**7.66**
F2010	**8.74**	**1.26**
F2011	**6.11**	**3.89**
F2012	**8.00**	**2.00**
F2013	**3.91**	**6.09**
F2014	**1.44**	**8.56**
F2015	**9.00**	**1.00**
F2016	**6.00**	**4.00**
F2017	**4.00**	**6.00**
F2018	**3.50**	**6.50**
F2019	**3.00**	**7.00**

8.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.3.2.2 LRMC, p. 2-46 Energy LRMC

On page 2-46, BC Hydro defines LRMC as the change in the long-run cost resulting from a change in the quantity of output produced. In short, LRMC represents the price of the most cost-effective way of satisfying incremental customer demand where existing resources are insufficient to meet that demand.

1.8.1 The energy LRMC was set out in the 2013 IRP. Please explain if the results of the conservation savings from the MGS and LGS Evaluation Report, which were considerably less than forecast, had been incorporated into the resource stacks and resource load balance in the 2013 IRP. If not, how would the difference between forecast and actual MGS and LGS conservation savings affect the estimate of the energy LRMC, if at all?

RESPONSE:

The difference between prior forecasted and actual MGS and LGS conservation savings is not expected to affect the estimate of the energy LRMC set out in the 2013 IRP. In particular, DSM and IPP EPA renewals remain the marginal resources.

The F2014 LGS and MGS Evaluation Report found that customer response to the existing LGS and MGS two part baseline rates was considerably less than forecast; consequently, forecast savings for the LGS/MGS rates were adjusted to zero. All else being equal, this would have the impact of requiring additional resources. BC Hydro notes that most energy savings from the LGS and MGS rates were planned prior to F2015. In particular, new incremental savings from the existing LGS/MGS rate were forecast to peak over F2012 to F2014, with minimal new incremental savings forecast from F2015 onwards. Put differently, the cumulative savings forecast from the LGS/MGS rates decline as the start year advances (numbers are rounded): 600 GWh/year (F2013 start year), 200 GWh/year (F2014 start year), 20 GWh (F2015 start year). The reason for the drop off in new incremental savings is because Tier 2 of the LGS/MGS rates was assumed to reach the energy LRMC by this time.

9.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.3.2.2, p. 2-52 and Integrated Resource Plan (Appendix 3B: Site C Information Sheet)
Energy LRMC

The Application states that DSM and Energy Purchase Agreement (EPA) renewals are marginal resources until about 2030, after which BC Hydro would require green-field clean or renewable independent power producers (IPPs). According to BC Hydro's Integrated Resource Plan (Appendix 3B: Site C Information Sheet), the estimated in-service date for Site C is fiscal 2024.

1.9.1 It doesn't appear that BC Hydro included Site C costs in its calculation of LRMC. If not, why not?

RESPONSE:

At the time of the 2013 IRP, while Site C was not considered a marginal resource, the Site C UEC was $83/MWh.

Site C is a committed resource and is under construction; therefore, it is not appropriate to include Site C in the LRMC. BC Hydro defines in its approved 2013 IRP that "committed resources" are resources for which material regulatory approvals have been secured (BCUC approval, either secured or through exemption; and environmental assessment related), if required, and for which the BC Hydro Board of Directors has authorized implementation. Material approvals such as from environmental assessment agencies and BC Hydro Board of Directors have been secured. Site C is in implementation phase with construction started on July 27, 2015.

9.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.3.2.2, p. 2-52 and Integrated Resource Plan (Appendix 3B: Site C Information Sheet)
Energy LRMC

The Application states that DSM and Energy Purchase Agreement (EPA) renewals are marginal resources until about 2030, after which BC Hydro would require green-field clean or renewable independent power producers (IPPs). According to BC Hydro's Integrated Resource Plan (Appendix 3B: Site C Information Sheet), the estimated in-service date for Site C is fiscal 2024.

1.9.2 If Site C costs were included in the calculation of LRMC, what would the inflation-adjusted range in the Energy LRMC be?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.9.1.

10.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.3.2.2, Tables 2-5 and 2-6, pp. 2-53 and 2-54
Energy LRMC

On page 2-53, BC Hydro states that: "BC Hydro reviewed distribution losses and finds that they are still reasonably close to 6 per cent of distribution load."

1.10.1 Based on this statement one would expect the difference between tables 2.5 and 2.6 to be, uniformly 6 percent, but this does not appear to be the case for all years. Why not?

RESPONSE:

The differences between Exhibit B-1, Table 2-5 and Table 2-6 should be 6 per cent. That was the case for the prices in BC Hydro's simulation years of F2017, F2018 and F2019. The LRMC estimated for F2014 to F2016 used a previous version of inflation assumptions. Having updated the inflation assumptions to match that of footnote 97, Table 2-6 is recalculated as follows. Note that the rates for F2017 to F2019 did not change.

Fiscal Year	Lower End of Energy LRMC Range (cents/kWh)	Upper End of Energy LRMC Range (cents/kWh)
F2013	**8.50**	**10.00**
F2013 (Distribution Loss 6 per cent):	**9.01**	**10.60**
F2014 (Revised)	**8.98**	**10.57**
F2015 (Revised)	**9.10**	**10.71**
F2016 (Revised)	**9.27**	**10.91**
F2017	**9.46**	**11.13**
F2018	**9.65**	**11.35**
F2019	**9.84**	**11.58**

11.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Sections 2.3.2.2 & 2.3.2.3 LRMC, p. 2-54 Table 2-6
Inflation adjusted range in energy LRMC for distribution service

On page 2-54, BC Hydro states that for purposes of this Application and as identified in the 2013 IRP, the LRMC for capacity resources is based on Revelstoke 6, the most cost-effective generation capacity on a unit cost basis.

1.11.1 On page 2-55, BC Hydro summarizes the grounds advanced by participants in the pre-filing workshops for including a generation capacity value in the energy LRMC. Both grounds involved the RIB rate. Please confirm that the small general service (SGS) rate structure also includes no demand charge. Please also confirm that the demand charge in SGS is recovered, in part, through the energy rate.

RESPONSE:

Confirmed that the SGS rate structure does not include a demand charge.

Confirmed that SGS demand-related embedded costs are recovered through the energy rate.

The lack of a demand charge is not justification for the inclusion of a generation capacity value in the energy LRMC for purposes of SGS rate-making. The SGS, MGS and LGS flat rate proposals are forecast revenue neutral, with the resulting charges (energy and basic in the case of SGS; energy, demand and basic in the case of MGS and LGS) reflecting embedded cost allocation. Please also refer to BC Hydro's response to BCUC IR 1.13.1.

11.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Sections 2.3.2.2 & 2.3.2.3 LRMC, p. 2-54 Table 2-6
Inflation adjusted range in energy LRMC for distribution service

On page 2-54, BC Hydro states that for purposes of this Application and as identified in the 2013 IRP, the LRMC for capacity resources is based on Revelstoke 6, the most cost-effective generation capacity on a unit cost basis.

1.11.2 Please replicate Table 2-6 with a column that includes capacity LRMC.

RESPONSE:

Exhibit B-1, Table 2-6 replicated with the inclusion of a capacity value based on the Rev 6 UCC is as follows. Note that this includes revisions per BC Hydro's response to BCUC IR 1.10.1 which uses the inflation assumptions as set out in Exhibit B-1 footnote 97 on page 2-53.

	Excludes Capacity LRMC		**With Capacity LRMC**	
Fiscal Year	**Lower End of Energy LRMC Range (cents/kWh)**	**Upper End of Energy LRMC Range (cents/kWh)**	**Lower End of Energy LRMC Range (cents/kWh)**	**Upper End of Energy LRMC Range (cents/kWh)**
F2013	**8.50**	**10.00**	**8.50**	**10.00**
+ F2013 (Distribution loss 6 per cent):	**9.01**	**10.60**	**9.01**	**10.60**
+ UCC of Rev 6 at 1.1c/kWh in F2013$	**N/A**		**10.11**	**11.70**
F2014	**8.98**	**10.57**	**10.08**	**11.66**
F2015	**9.10**	**10.71**	**10.21**	**11.82**
F2016	**9.27**	**10.91**	**10.40**	**12.04**
F2017	**9.46**	**11.13**	**10.61**	**12.28**
F2018	**9.65**	**11.35**	**10.83**	**12.53**
F2019	**9.84**	**11.58**	**11.04**	**12.78**

For completeness BC Hydro also provides Table 2-5 replicated with the inclusion of a capacity value based on the Rev 6 UCC.

	Excludes Capacity LRMC		With Capacity LRMC	
Fiscal Year	**Lower End of Energy LRMC Range (cents/kWh)**	**Lower End of Energy LRMC Range (cents/kWh)**	**Lower End of Energy LRMC Range (cents/kWh)**	**Upper End of Energy LRMC Range (cents/kWh)**
F2013	**8.50**	**10.00**	**8.50**	**10.00**
+ UCC of Rev 6 at 1.1c/kWh in F2013$			**9.60**	**11.10**
F2014	**8.47**	**9.97**	**9.57**	**11.07**
F2015	**8.58**	**10.10**	**9.70**	**11.21**
F2016	**8.75**	**10.29**	**9.88**	**11.42**
F2017	**8.92**	**10.50**	**10.08**	**11.65**
F2018	**9.10**	**10.71**	**10.28**	**11.89**
F2019	**9.28**	**10.92**	**10.48**	**12.12**

11.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Sections 2.3.2.2 & 2.3.2.3 LRMC, p. 2-54 Table 2-6
Inflation adjusted range in energy LRMC for distribution service

The Application states on page 2-54 that the 2013 IRP shows that the unit capacity cost (UCC) of natural gas-fired simple cycle gas turbine generators (SCGTs) would be $88/kW-year. Table 3-27 on page 3-75 of the 2013 IRP shows the UCC cost of SCGTs at two locations would be $84 or $180.

1.11.3 Please explain the discrepancy between the IRP cost estimate and that cited in the Application.

RESPONSE:

The RDA-related SCGT UCC $88/kW-year estimate includes a 5 per cent soft cost adder on top of the $84/kW-year estimate. As described in the 2013 IRP (Appendix 3A-34), the 5 per cent adder was chosen based on BC Hydro's experience to reflect cost expenditures such as environmental assessment, First Nations and stakeholder engagement costs, etc.

12.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.3.2. Current Environment Context, p. 2.54
LRMC for Distribution Service; Commission Reasons for Decision to Order G-124-08

Commission Reasons for Decision to Order G-124-08 on the BC Hydro RIB Rate Application states: "BC Hydro estimated that about three to four cents/kwh … ought to be added to the marginal cost of new energy supply for the purpose of establishing the marginal rate ceiling …" (pp. 92, 93)

1.12.1 Please estimate (in $/k@-year and cents/kwh equivalent) the F2016 BC Hydro 'transmission LRMC' and 'network (transmission plus distribution) LRMC for load located in the Lower Mainland.

RESPONSE:

BC Hydro does not have a marginal COS study that estimates the marginal cost of incremental transmission and distribution, and therefore cannot provide the requested information.

12.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.3.2. Current Environment Context, p. 2.54
LRMC for Distribution Service; Commission Reasons for Decision to Order G-124-08

Commission Reasons for Decision to Order G-124-08 on the BC Hydro RIB Rate Application states: "BC Hydro estimated that about three to four cents/kwh … ought to be added to the marginal cost of new energy supply for the purpose of establishing the marginal rate ceiling …" (pp. 92, 93)

1.12.2 Does BC Hydro consider that a reasonable proxy for the 'network LRMC' could be BC Hydro's embedded network costs? Please explain.

RESPONSE:

No. An estimate of "network LRMC" (transmission plus distribution) would require a marginal COS analysis.

12.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.3.2. Current Environment Context, p. 2.54
LRMC for Distribution Service; Commission Reasons for Decision to Order G-124-08

Commission Reasons for Decision to Order G-124-08 on the BC Hydro RIB Rate Application states: "BC Hydro estimated that about three to four cents/kwh … ought to be added to the marginal cost of new energy supply for the purpose of establishing the marginal rate ceiling …" (pp. 92, 93)

1.12.3 Please explain what the 'three to four cents/kwh' in BC Hydro's 2008 RIB proceeding was intended to represent, and if BC Hydro has improved the accuracy of this costing data for the 2015 RDA.

RESPONSE:

BC Hydro does not understand the assumption in the IR that the issue raised relates in any way to the accuracy of costing data.

The three to four cents/kWh represented the embedded costs of delivering energy to Residential customers. The issue was whether it was appropriate to add these embedded delivery costs to the total LMRC supplying energy to Residential customers for the purpose of establishing a marginal rate ceiling that would allow comparison between the energy charges of the RIB rate and RS 1823. In its Reasons for Decision accompanying Commission Order No. G-124-08, page 107, the Commission found little evidence to support the gross up of three to four cents and none of it to be persuasive.

12.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.3.2. Current Environment Context, p. 2.54
LRMC for Distribution Service; Commission Reasons for Decision to Order G-124-08

Commission Reasons for Decision to Order G-124-08 on the BC Hydro RIB Rate Application states: "BC Hydro estimated that about three to four cents/kwh … ought to be added to the marginal cost of new energy supply for the purpose of establishing the marginal rate ceiling …" (pp. 92, 93)

1.12.4 Please updated table 2-5 and 2-6 in the Application to show BC Hydro's "total LRMC" (i.e., energy, capacity and network)

RESPONSE:

As indicated the response to BCUC IR 1.12.1, BC Hydro does not have a marginal COS study and cannot provide information relating to cost of incremental transmission and distribution. Please refer to BC Hydro's response to BCUC IR 1.11.2 which replicates Table 2-6 of Exhibit B-1 with a column that includes the value of generation capacity in the energy LMRC.

13.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.3.2.3, p. 2-55, and Section 5.2.5.1, p. 5-34, Fig. 5-18
Capacity LRMC and Step 2 RIB pricing

On page 2-55, the Application notes that while the RIB is an energy conservation rate, it delivers anticipated capacity savings, and states that "BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction."

BC Hydro also references the 2011 RIB Re-Pricing Decision where the Commission stated that the RIB Step 2 rate should be based on a "price signal for customers to understand *what is happening to the cost of energy* they will consume in the future" (emphasis added by BC Hydro).

1.13.1 Notwithstanding the Commission's previous findings on the issue, and the fact that the RIB Step 2 rate is generally referred to as the Step 2 energy rate, does naming the rate an "energy rate" or an "energy conservation rate" reflect an overly precise view of the rate, given the anticipated capacity savings, and if so should a capacity value be included in the LRMC? If not, why not?

RESPONSE:

In BC Hydro's review, reference in RS 1101/RS 1121 (the RIB rate) Step 2 rates as the 'Energy Charge', or the general naming of the RIB Step 2 rate as an 'energy rate' simply reflects that it is a charge for energy consumed. The naming does not necessarily reflect the costs to be recovered through the charge and as such it is not an overly precise view of the rate. The decision to include some amount of generation capacity costs in the calculation of the LRMC is not dependent on how the RIB Step 2 rate is named or referenced.

BC Hydro believes that the RIB rate is designed to produce energy conservation. While BC Hydro expects the RIB rate to result in capacity savings, those capacity savings are a byproduct of the customer energy reductions. The RIB Step 2 rate does not have a peak period component to directly incent peak demand reductions. As such, BC Hydro continues to propose that the LRMC estimate of the incremental costs of energy as the benchmark for the RIB Step 2 rate.

13.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.3.2.3, p. 2-55, and Section 5.2.5.1, p. 5-34, Fig. 5-18
Capacity LRMC and Step 2 RIB pricing

Figure 5-18: Requested RIB Rate Pricing Principles Option 1 shows that for the period F2017–F2019 the Step 2 rate is approximately equal to or above an LRMC that includes a capacity cost based on the UCC of Revelstoke Unit 6.

1.13.2 Please confirm that, even though the proposed Step 2 rate approximates the LRMC that includes a capacity cost, BC Hydro does not agree that including a capacity cost in the LRMC for the purpose of setting a Step 2 rate is appropriate (for the reasons set out in section 2.3.2.3), and that the proposed step 2 rate is the result of its proposal to maintain the current differential between the Step 1 and Step 2 energy rates, rather than the use of an LRMC that includes a capacity cost as a reference point.

RESPONSE:

It is correct that BC Hydro's proposed RIB rate F2017-F2019 pricing principles (Option 1, described at page 5-34 of Exhibit B-1) has the effect of maintain the current differential between the RIB Step 1 and Step 2 energy rates. BC Hydro prefers Option 1 as compared to RIB rate F2017-F2019 pricing principle Option 2 on the basis of customer understanding and acceptance (bill impacts, and easily understood and communicated; refer to Exhibit B-1, page 5-39, line 8 to page 5-41, line 2). It also correct that BC Hydro did not propose Option 1 on the basis of use of an energy LRMC that includes a capacity cost as a reference point.

With respect to whether the energy LRMC should include a generation capacity value for purposes of the RIB Step 2 rate, please refer to BC Hydro's response to BCUC IR 1.13.1.

14.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.4, Rate Assessment Methodology, pp. 2-58 and 2-59; Section 5, 2.5.1, Figures 5-20 to 5-22
Bonbright Criteria – Ten percent bill impact test

…BC Hydro uses the 10 per cent bill impact test as an amber signal rather than a stop-or-go constraint. For example, BC Hydro believes that it is acceptable for bill impacts to exceed 10 per cent per year where the absolute dollar value of the increases is very small.

…Some stakeholders suggested using the 95 percentile or 90 percentile. After calculating the bill impacts of all customers and then sorting from the highest percentage increase to the lowest percentage increase, the customer that is 95 per cent of the way up the ranking would be the 95th percentile customer on bill impact. In BC Hydro's view, applying the 10 per cent test to any threshold level other than the most adversely impacted customer will lead to definitional problems or will have unintended consequences.

1.14.1 Please explain why BC Hydro considers that the 10 percent test should be applied only to the most adversely impacted customer when that criterion may impede progress towards fair pricing for the vast majority of a rate class.

RESPONSE:

The 10 per cent bill impact test is used in two different contexts.

Context 1: Modelling design

The first context is in modelling a design that requires optimization to a specific bill impact constraint to provide a single solution. Optimization to the most adversely impacted customer ensures that to be the case. Using a threshold such as a 90th percentile can lead to an unsolvable model - a key "unintended consequence". This is especially the case for designs that have a complex relationship between bill impact and consumption, where higher consumption does not necessarily mean higher bill impacts. For example, Three Step B and Three Step C both have customers near the median having the most adverse bill impact.

Often the intent of a constraint using the most adversely impacted customer is to prevent customer exposure to an impact that is too high. Using a threshold such as a 90th percentile would override that intent. A more preferred alternative is to

relax the constraint and set a higher bill impact threshold for the most adversely impacted customer.

Note that none of the proposed Residential or General Service default rate designs have bill impact optimization as a feature.

Context 2: Analysis

The second context is in analysis. While BC Hydro uses the 10 per cent bill impact test as an amber signal, BC Hydro is of the view that the analysis of each design should take into consideration of the full bill impact distribution as well as the other Bonbright criteria as shown in Exhibit B-1, Table 2-7. The full range of distribution of bill impacts is presented in the form of box plots, as shown in Exhibit B-1, Figures 5-14, 5-17, and 5-23.

As discussed during Workshop 3, a common misconception is that the most adversely impacted customers are usually outliers or extreme customers with very high consumption, and using the 90th or 95th percentile customer will yield customers that are less extreme. However, that is not always the case. Examples of this includes RIB rate pricing principle Option 2 (Exhibit B-1, Figure 5-20), and the Residential flat rate alternative (Exhibit B-1, Figure 5-13), which yield the most adversely impacted customer near the median consumption.

14.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.4, Rate Assessment Methodology, pp. 2-58 and 2-59; Section 5, 2.5.1, Figures 5-20 to 5-22
Bonbright Criteria – Ten percent bill impact test

…BC Hydro uses the 10 per cent bill impact test as an amber signal rather than a stop-or-go constraint. For example, BC Hydro believes that it is acceptable for bill impacts to exceed 10 per cent per year where the absolute dollar value of the increases is very small.

…Some stakeholders suggested using the 95 percentile or 90 percentile. After calculating the bill impacts of all customers and then sorting from the highest percentage increase to the lowest percentage increase, the customer that is 95 per cent of the way up the ranking would be the 95th percentile customer on bill impact. In BC Hydro's view, applying the 10 per cent test to any threshold level other than the most adversely impacted customer will lead to definitional problems or will have unintended consequences.

1.14.2 Please explain or discuss the "unintended consequences."

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.14.1.

14.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.4, Rate Assessment Methodology, pp. 2-58 and 2-59; Section 5, 2.5.1, Figures 5-20 to 5-22
Bonbright Criteria – Ten percent bill impact test

…BC Hydro uses the 10 per cent bill impact test as an amber signal rather than a stop-or-go constraint. For example, BC Hydro believes that it is acceptable for bill impacts to exceed 10 per cent per year where the absolute dollar value of the increases is very small.

…Some stakeholders suggested using the 95 percentile or 90 percentile. After calculating the bill impacts of all customers and then sorting from the highest percentage increase to the lowest percentage increase, the customer that is 95 per cent of the way up the ranking would be the 95th percentile customer on bill impact. In BC Hydro's view, applying the 10 per cent test to any threshold level other than the most adversely impacted customer will lead to definitional problems or will have unintended consequences.

1.14.3 Would BC Hydro agree that a situation where it might be appropriate to use a 90th or 95th percentile customer in the bill impact test might be where the data shows a significant discontinuity at the extreme ends of the population distribution (i.e. where the energy consumption of the 100th percentile customers was significantly higher or lower than any other customer)? If not, why not?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.14.1.

14.0 A. CHAPTERS 1 & 2 – INTRODUCTION, STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION

Reference: Exhibit B-1, Application, Section 2.4, Rate Assessment Methodology, pp. 2-58 and 2-59; Section 5, 2.5.1, Figures 5-20 to 5-22
Bonbright Criteria – Ten percent bill impact test

…BC Hydro uses the 10 per cent bill impact test as an amber signal rather than a stop-or-go constraint. For example, BC Hydro believes that it is acceptable for bill impacts to exceed 10 per cent per year where the absolute dollar value of the increases is very small.

…Some stakeholders suggested using the 95 percentile or 90 percentile. After calculating the bill impacts of all customers and then sorting from the highest percentage increase to the lowest percentage increase, the customer that is 95 per cent of the way up the ranking would be the 95th percentile customer on bill impact. In BC Hydro's view, applying the 10 per cent test to any threshold level other than the most adversely impacted customer will lead to definitional problems or will have unintended consequences.

1.14.4 Referring to the plots in Figures 5-20 to 5-22, in BC Hydro's view does the consumption pattern of residential customers show enough continuity in the distribution of energy consumption to support relying on the 100th percentile rather than the 90th or 95th percentile? Please explain why or why not.

RESPONSE:

RIB rate pricing principle Option 2's design does not include bill impact optimization as a feature, so the maximum bill impact threshold was not used as a constraint in its design. The continuity of customer distribution has no impact on the modelled rate.

Exhibit B-1, Figure 5-20 shows the bill impact distribution for Option 2 for F2017, while Figures 5-21 and 5-22 show the cumulative bill impact distribution up to F2018 and F2019, respectively. The simulations show that no customer is anticipated to experience bill impacts exceeding 10 per cent for any year, or cumulative bill impacts exceeding 10 per cent in F2017, 21 per cent in F2018, and 33 per cent in F2019.

15.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1, Application, Section 3.1.2 F2016 COS Study, p. 3-2
Filing of Annual Fully Allocated COS (FACOS)

On page 3-2, BC Hydro says that it would continue to submit FACOS results with the Commission every year pursuant to 2007 RDA Direction 2. The FACOS would reflect any Commission findings concerning the F2016 COS.

1.15.1 Please clarify if it is BC Hydro's intention to file FACOS results annually with the Commission pursuant to the methodologies approved in the 2007 RDA, <u>in addition to</u> any newly approved or endorsed methodologies in the 2015 RDA decision.

RESPONSE:

It is BC Hydro's intention to file FACOS results annually with the Commission pursuant to the methodologies approved in the 2007 RDA as amended by any approved or endorsed methodologies in the 2015 RDA decision.

16.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1, Application, Section 3.1 Cost of Service, pp. 3-1 and 3-2
Lieutenant Governor in Council rate rebalancing amendment

BC Hydro identifies on page 3-1 that: "…rate design is informed by a comparison of energy, demand and customer-related costs, as identified in the F2016 COS study, and revenue from energy, demand and basic charges."

BC Hydro further states on page 3-2 that: "The F2019 COS would be the subject of stakeholder engagement prior to filing and would include a rate rebalancing proposal if appropriate. BC Hydro would continue to submit Fully Allocated COS results with the Commission every year pursuant to 2007 RDA Direction 2."

1.16.1 Since the Commission cannot use this COS review for the purpose of changing the revenue-to-cost (R/C) ratios, and since the proposed shifts in basic charges and demand cost revenue collection are well below the allocated costs, is there much purpose in undertaking a detailed evaluation of the 2016 COS Study (COSS)? Please discuss.

RESPONSE:

BC Hydro respectfully submits that this issue was the subject of the written submission process established by Commission Order No. G-156-15 (Exhibit A-2) as modified by Commission Order No. G-166-15 (Exhibit A-3), with the result that the Commission determined that the F2016 COS is in scope for the first round of IRs (Commission Order No. G-175-15, Appendix A, page 2 of 10 (Exhibit A-4)).

BC Hydro's position on this topic is set out in Exhibit B-2, pages 1-3 and Exhibit B-3, pages 2-4, both of which were submitted as part of the written submission process outlined above. The F2016 COS is evidence for both RDA Module 1 and RDA Module 2 rate design purposes, and accordingly the F2016 COS-related inputs and results should be reviewed by the Commission.

16.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1, Application, Section 3.1 Cost of Service, pp. 3-1 and 3-2
Lieutenant Governor in Council rate rebalancing amendment

BC Hydro identifies on page 3-1 that: "…rate design is informed by a comparison of energy, demand and customer-related costs, as identified in the F2016 COS study, and revenue from energy, demand and basic charges."

BC Hydro further states on page 3-2 that: "The F2019 COS would be the subject of stakeholder engagement prior to filing and would include a rate rebalancing proposal if appropriate. BC Hydro would continue to submit Fully Allocated COS results with the Commission every year pursuant to 2007 RDA Direction 2."

1.16.1.1 BC Hydro is proposing to continue to submit its annual Fully Allocated COS results in the intervening years before a full COSS in F2019. What is BC Hydro's expectation in how the Commission would use the information filed?

RESPONSE:

BC Hydro has been filing annual FACOS in compliance with Commission Directive 2 of the 2007 RDA Decision. In BC Hydro's view, annual FACOS filings allow for early identification of R/C ratio trends.

17.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1, Application, Section 3.5.2, Cost of Service, p. 3-10, Table 3-1 & Table 3-6
2007 RDA COS methodology

1.17.1 Please provide a revised Table 3-6 in which the right-hand column is calculated using the same data as was used for the final F2016 COS study. Are the differences in the R/C ratios an indication of the legitimate differences in assumptions as they impact the accuracy of the final R/C findings?

RESPONSE:

The table below shows the actual F2013 R/C ratios and the forecast F2016 R/C ratios, using the approved 2007 RDA Decision COS methodology. Differences in results from year to year reflect changes in load, changes in revenue, and the changes in costs by function. There is no difference in assumptions for the requested comparison, as the methodology employed is identical in both years. However, the F2016 R/C ratios are provided on a forecast basis and are subject to change when updated with actual F2016 data.

Rate Class	F2013 Filed R/C ratios using 2007 RDA Decision Methodology	F2016 Forecast R/C ratios using 2007 RDA Decision Methodology
Residential	**89.8**	**91.7**
SGS	**126.7**	**118.3**
MGS	**120.8**	**120.9**
LGS	**102.1**	**99.4**
Irrigation	**86.6**	**92.9**
Street Lighting	**115.7**	**126.5**
Transmission	**104.4**	**105.4**

18.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.5.4, pp. 3-12 and 3-13 Load data

On pages 3-12 and 3-13, BC Hydro discusses the increased accuracy of the load research data and customer load profiles due to SMI.

1.18.1 Please identify and quantify the benefits, if any, which are created by the increased accuracy of the load data or a reduction in the costs of acquiring the data.

RESPONSE:

The improved load research data, in the form of increased sample sizes, results in more accurate estimates of the rate class peak demand values, which are inputs to the F2016 COS study. This increased accuracy is one reason why BC Hydro proposed a range of reasonableness of 95 per cent/105 per cent in its Workshop 2 Strawman proposal (refer to pages 264 and 265 of 439, Appendix C-2A of Exhibit B-1).

The improved peak demand estimates are expected to be within 1 per cent with a 99 per cent confidence for the LGS and MGS rate classes, and within 5 per cent with a 95 per cent confidence for the SGS and Residential rate classes. Previously, the restricted size of load research samples limited the accuracy of these rate class peak demands to 10 per cent with a 90 per cent confidence.

18.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.5.4, pp. 3-12 and 3-13
Load data

On pages 3-12 and 3-13, BC Hydro discusses the increased accuracy of the load research data and customer load profiles due to SMI.

1.18.2 Are any such benefits included in the allocation of Smart Meter Infrastructure (SMI) costs? If so, how, and if not, should they be?

RESPONSE:

No. Consistent with BC Hydro's cost of service methodology, recoveries associated with SMI costs are allocated by cost causation principles. The benefits associated with better data allow costs to be better allocated among the rate classes that have caused costs to be incurred.

18.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.5.4, pp. 3-12 and 3-13 Load data

BC Hydro refers to the availability of SMI information for analysis that "can be done" and "would yield" much greater accuracy.

1.18.3 Please confirm that the detailed SMI information was used as described on pages 3-12 and 3-13 in the development of residential load profiles and demand usage. If not, why not?

RESPONSE:

Confirmed.

19.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.6.3, p. 3-14
Functionalization of Generation

BC Hydro says that subsidiary net income, which is primarily derived from Powerex, is assigned to the Generation function on the basis that the income is associated with energy sales.

1.19.1 Presumably, Powerex energy sales require delivery on the BC Hydro transmission system to an Interconnection with a neighbouring system. Please confirm that none of the subsidiary net income is assigned to the Transmission function, and the reason for that is because any transmission-related revenues in the gross income are offset by charges for transmission under the OATT and any other transmission charges on neighbouring systems. If that is not the case, please explain.

RESPONSE:

BC Hydro confirms that Powerex's net income is not functionalized to Transmission in the F2016 COS study. Powerex pays BC Hydro directly for the use of the BC Hydro transmission system and includes the payment as a cost in its calculation of net income. This transmission payment lowers the costs that must be recovered from BC Hydro's network customers.

There are no transmission service related "revenues" in Powerex's gross income. Powerex net income reflects the revenue associated with energy sales (i.e., sales of electricity, natural gas and renewable attributes) after the deduction of all costs including the cost of BC Hydro transmission services.

20.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.6.3, p. 3-14
Sub-functionalization of Distribution

BC Hydro states that it has sub-functionalized the Distribution system into: substations, primary system, transformers, secondary/services and meters, based on the advice of the COS consultants and the Commission's comment in the 2007 RDA.

1.20.1 Please provide a reference in the COS model where this sub-functionalization is shown.

RESPONSE:

The Distribution sub-functionalization was provided as Schedule 6 of the COS model and is shown in Exhibit B-1, page 27 of 79 in Appendix C-2C.

21.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.6.5, pp. 3-15 to 3-17; Appendix C-2A, Cost of Service Methodology Review (leidos report), p. 4-7; and Appendix C-2B, Workshop 4 Consideration Memo, p. 31, Table 8 Functionalization procedure

BC Hydro says that it functionalizes O&M costs using Schedules 5.0 to 5.4 of the F2015-F2016 RRA Financial model, which map business groups to different functional areas. If a business group provides services to multiple functional areas (e.g. Environmental Risk Management or Aboriginal Relations), the RRA maps it according to the functional area that captures a majority of the costs incurred.

BC Hydro also says that it considered using bottom-up methods to estimate the proportion of work that spans multiple functional areas, but observed that it would be administratively complex without a corresponding gain in accuracy. On pages 3-16 and 3-17, BC Hydro sets out four reasons for choosing to functionalize business group costs entirely to the predominant functional areas.

Reason 1 on page 3-16 states that with the exception of IT costs, the total dollars from business groups that span multiple functional areas are relatively small, representing less than one percent of the F2016 revenue requirement. Reason 2 states that the difference between splitting the costs among multiple functional areas versus functionalizing to a primary group has a negligible impact on R/C ratios.

The leidos report says on page 4-7 that:

One general observation we made from our review of the BC Hydro COS model is that BC Hydro utilized a more limited sub-functionalization of its revenue requirement compared with the levels being used by other utilities of similar size and complexity. Significantly greater detailed information for both costs and operational aspects of the utility may be available to BC Hydro, and this more detailed information may add value if incorporated into the COS methodology.

1.21.1 Is BC Hydro's decision not to use "bottom up" methods essentially a decision to reject the observation of the leidos report that BC Hydro might benefit from a higher degree of sub-functionalization? Please explain.

RESPONSE:

BC Hydro has not rejected sub-functionalization for purposes of developing the F2016 COS study.

The COS Methodology Review (found in Appendix C-2A of Exhibit B-1) recommendation that greater sub-functionalization be explored refers to the broader COS study and BC Hydro's treatment of costs within the generation, transmission, distribution and

customer care functions. The COS Methodology Review does not address IT costs, including whether to use a bottom up approach. The "bottom up methods" described on page 3-16 of Exhibit B-1 refer to the functionalization of costs from business groups that span multiple functional areas. BC Hydro estimated that these costs account for about "$40 million in F2016 which represents less than 1 per cent of the F2016 revenue requirement".

Sub-Functionalization Undertaken

The 2007 RDA COS study already incorporated sub-functionalization. For example:

- **Different classifications are applied to hydroelectric (plant and O&M), hydroelectric water rentals, thermal, IPP and market purchase generation costs; and**

- **A portion of the transmission system is already sub-functionalized because GRTA are treated as a generation cost rather than a transmission cost. Similarly, substations are sub-functionalized between transmission and distribution as part of the determination of SDA.**

BC Hydro considered additional sub-functionalization during the development of the F2016 COS study and adopted the COS Methodology Review recommendation with respect to distribution system costs, which are now sub-functionalized into substations, primary, transformers, secondary and services.

Sub-Functionalization Rejected

Examples where additional sub-functionalization was considered but rejected include:

- **The COS Methodology Review recommended (page 59 of 439) that BC Hydro consider a "plant capacity factor approach that sub-functionalizes hydro plant in service and O&M costs by individual plant or groups of plants". BC Hydro rejected this approach after the assessment described in the Workshop 4 consideration memo (refer to section 2.1.2; copy found at Appendix C-2B of Exhibit B-1); and**

- **BC Hydro rejected a detailed sub-functionalization and allocation of Customer Care costs in favor of the current 90 per cent/10 per cent weighted allocator for reasons discussed in section 9 of the Workshop 4 Discussion Guide (copy found at Appendix C-2B of Exhibit B-1).**

21.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.6.5, pp. 3-15 to 3-17; Appendix C-2A, Cost of Service Methodology Review (leidos report), p. 4-7; and Appendix C-2B, Workshop 4 Consideration Memo, p. 31, Table 8
Functionalization procedure

BC Hydro says that it functionalizes O&M costs using Schedules 5.0 to 5.4 of the F2015-F2016 RRA Financial model, which map business groups to different functional areas. If a business group provides services to multiple functional areas (e.g. Environmental Risk Management or Aboriginal Relations), the RRA maps it according to the functional area that captures a majority of the costs incurred.

BC Hydro also says that it considered using bottom-up methods to estimate the proportion of work that spans multiple functional areas, but observed that it would be administratively complex without a corresponding gain in accuracy. On pages 3-16 and 3-17, BC Hydro sets out four reasons for choosing to functionalize business group costs entirely to the predominant functional areas.

Reason 1 on page 3-16 states that with the exception of IT costs, the total dollars from business groups that span multiple functional areas are relatively small, representing less than one percent of the F2016 revenue requirement. Reason 2 states that the difference between splitting the costs among multiple functional areas versus functionalizing to a primary group has a negligible impact on R/C ratios.

The leidos report says on page 4-7 that:

One general observation we made from our review of the BC Hydro COS model is that BC Hydro utilized a more limited sub-functionalization of its revenue requirement compared with the levels being used by other utilities of similar size and complexity. Significantly greater detailed information for both costs and operational aspects of the utility may be available to BC Hydro, and this more detailed information may add value if incorporated into the COS methodology.

1.21.1.1 Table 8 on page 31 of the Workshop 4 Consideration Memo indicates that BC Hydro has diverged from Direction 4 of the 2007 RDA Decision, and has sub-functionalized the distribution system. Is this an instance where BC Hydro has adopted the observation of the leidos report? If so, has BC Hydro adopted the leidos recommendation to increase the degree of sub-functionalization anywhere else in the F2016 COS study?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.21.1.

21.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.6.5, pp. 3-15 to 3-17; Appendix C-2A, Cost of Service Methodology Review (leidos report), p. 4-7; and Appendix C-2B, Workshop 4 Consideration Memo, p. 31, Table 8 Functionalization procedure

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1.21.2 Please provide an approximate estimate of the accuracy of the R/C ratios derived from the business group mapping method that BC Hydro has used (e.g. +0.1 to -0.05).

RESPONSE:

BC Hydro cannot quantify the accuracy of R/C ratios derived from a business group mapping method but noted on page 3-16 of Exhibit B-1 that the total dollars from business groups that span multiple functional areas are relatively small ($40 million in F2016). This is illustrated in the R/C ratio analysis below that re-functionalizes $40 million in OM&A cost as either entirely Generation or entirely Transmission.

Scenario	Change to R/C Ratios Relative to the F2016 COS Study		
	Residential (%)	LGS (%)	Transmission (%)
1) $40 million in cost entirely functionalized to Generation	0.1	-0.1	-0.3
2) $40 million in cost entirely functionalized to Transmission	-0.1	0.1	0.3

21.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.6.5, pp. 3-15 to 3-17; Appendix C-2A, Cost of Service Methodology Review (leidos report), p. 4-7; and Appendix C-2B, Workshop 4 Consideration Memo, p. 31, Table 8 Functionalization procedure

BC Hydro says that it functionalizes O&M costs using Schedules 5.0 to 5.4 of the F2015-F2016 RRA Financial model, which map business groups to different functional areas. If a business group provides services to multiple functional areas (e.g. Environmental Risk Management or Aboriginal Relations), the RRA maps it according to the functional area that captures a majority of the costs incurred.

BC Hydro also says that it considered using bottom-up methods to estimate the proportion of work that spans multiple functional areas, but observed that it would be administratively complex without a corresponding gain in accuracy. On pages 3-16 and 3-17, BC Hydro sets out four reasons for choosing to functionalize business group costs entirely to the predominant functional areas.

Reason 1 on page 3-16 states that with the exception of IT costs, the total dollars from business groups that span multiple functional areas are relatively small, representing less than one percent of the F2016 revenue requirement. Reason 2 states that the difference between splitting the costs among multiple functional areas versus functionalizing to a primary group has a negligible impact on R/C ratios.

The leidos report says on page 4-7 that:

One general observation we made from our review of the BC Hydro COS model is that BC Hydro utilized a more limited sub-functionalization of its revenue requirement compared with the levels being used by other utilities of similar size and complexity. Significantly greater detailed information for both costs and operational aspects of the utility may be available to BC Hydro, and this more detailed information may add value if incorporated into the COS methodology.

1.21.3 Please provide an approximate estimate of the accuracy of the R/C ratios that would be created if a “bottom up” or sub-functionalization approach was broadly used (e.g. in areas such as customer care costs).

RESPONSE:

R/C ratio accuracy is largely a function of load data quality. Please refer to section 3.5.4 of Exhibit B-1. While sub-functionalization improves transparency, it may or may not improve accuracy which depends on data quality, assumptions used, etc.

22.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.6.5, pp. 3-15 and 3-16 Functionalization of Aboriginal Relations costs

BC Hydro says that the operating costs of its Aboriginal Relations group are functionalized entirely to T&D even though some of the operating cost is likely Generation related.

1.22.1 Schedule 5.4 of the F2015–F2016 RRA Financial model shows Aboriginal Relations operating costs of $5.1 million under T&D and $0 in Schedule 5.2 under generation. However, Schedule 1.0: Functionalization Details of the COS model appears to show that, out of a total of approximately $43 million of OM&A related to First Nations, about $19 million was functionalized to Generation and $24 million to Transmission. Please explain these differences.

RESPONSE:

The amounts from RRA Schedules 5.4 and 5.2 are current year OMA expense for the Aboriginal Relations business unit.

The amounts on Schedule 1.0 of the COS model (Appendix E, Exhibit B-1) include recovered amounts associated with the First Nations regulatory account.

23.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.6.6, pp. 3-19 and 3-20; Appendix C-2B, Workshop 4 Consideration Memo, p. 7; and Appendix C-2A, Cost of Service Methodology Review (leidos report), p. 4-6
Demand-side management

BC Hydro has proposed to functionalize DSM as 90 percent generation, 5 percent transmission and 5 percent distribution, but notes on page 7 of the Workshop 4 Consideration Memo (in Appendix C-2B) that "…allocation of the final 10 per cent wholly to Generation, wholly to Transmission, or as between Transmission and Distribution, will not materially impact the allocation of cost to rate classes."

The Cost of Service Methodology Review (leidos report) on page 4-6, recommends that "…BC Hydro consider functionalizing DSM costs based on the relative proportions of BC Hydro's generation plant in service to transmission plant in service. As such, the functionalization approach would be consistent with the classification approaches."

1.23.1 If BC Hydro adopted the approach recommended by the leidos report, what would be the functionalization percentages of DSM costs?

RESPONSE:

Using the end of year F2016 rate base values for Generation and Transmission of $7.6 billion and $6.3 billion respectively, the functionalization percentages would be would about 55 per cent Generation and 45 per cent Transmission. Please refer to RRA Schedule 10.0 of the F2016 COS model found in Appendix E of Exhibit B-1.

23.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.6.6, pp. 3-19 and 3-20; Appendix C-2B, Workshop 4 Consideration Memo, p. 7; and Appendix C-2A, Cost of Service Methodology Review (leidos report), p. 4-6
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The Cost of Service Methodology Review (leidos report) on page 4-6, recommends that "…BC Hydro consider functionalizing DSM costs based on the relative proportions of BC Hydro's generation plant in service to transmission plant in service. As such, the functionalization approach would be consistent with the classification approaches."

1.23.2 Please discuss why BC Hydro has rejected the approach recommended by leidos in favour of its proposed functionalization of DSM costs.

RESPONSE:

BC Hydro responded to this recommendation in the Workshop 2 Discussion Paper (refer to pages 243 to 245 of 439, Appendix C-2A of Exhibit B-1). As part of its preparation for Workshop 2, BC Hydro discussed its DSM functionalization proposal with the COS Consultants and they agreed the functionalization approach is reasonable.

24.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1, Application, Chapter 3 Cost of Service, pp. 3-20 – 3-21;
Appendix C-2B, Workshop 4 Discussion Guide, p. 5
Functionalization of regulatory accounts

In Appendix C2-B (p. 64 of 205), BC Hydro states:

Deferral accounts have historically been functionalized as 100% Generation and classified as 42% energy and 58% demand, which is the classification for the aggregate Generation costs using a plant-in-service ratio. Going forward, BC Hydro proposes to align Deferral account classification with total Cost of Energy which has a split of about 90% energy and 10% demand.

Regulatory accounts have historically been lumped together with Deferral accounts but not all of these accounts should be functionalized as Generation."

1.24.1 Please explain and clarify the difference between Regulatory accounts and Deferral accounts. What are the properties and cost drivers of each type?

RESPONSE:

Deferral accounts refer to BC Hydro's three energy deferral accounts, namely the Heritage Deferral Account, the Non-Heritage Deferral Account and the Trade Income Deferral Account. Regulatory accounts refer to BC Hydro's non-energy related deferral accounts. BC Hydro's deferral and regulatory accounts will be discussed in the F2017 RRA, which will be filed with the Commission in February 2016.

24.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1, Application, Chapter 3 Cost of Service, pp. 3-20 – 3-21;
Appendix C-2B, Workshop 4 Discussion Guide, p. 5
Functionalization of regulatory accounts

BC Hydro explains that the Rate Smoothing regulatory account, an amount of $122.4 million in the F2016 RRA, was previously assigned to each function proportionate with functionalized O&M.

1.24.2 Please explain the rationale behind the previous functionalization to O&M. Are all of the accruals into the Rate Smoothing regulatory account necessarily all related to O&M costs? If not, please explain whether amounts related to costs other than O&M are material, and if so, what they are related to.

RESPONSE:

The annual recovery of amounts related to the Rate Smoothing regulatory account has been functionalized previously as a Corporate operating cost because the annual amount included in the revenue requirement is not comprised of specific accruals that may otherwise be functionalized. Upon review of the function of the Rate Smoothing regulatory account, BC Hydro's COS Consultants recommended the approach proposed in the 2015 RDA, which separately functionalizes the Rate Smoothing regulatory account amounts from other corporate operating costs.

24.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1, Application, Chapter 3 Cost of Service, pp. 3-20 – 3-21;
Appendix C-2B, Workshop 4 Discussion Guide, p. 5
Functionalization of regulatory accounts

BC Hydro explains that the Rate Smoothing regulatory account, an amount of $122.4 million in the F2016 RRA, was previously assigned to each function proportionate with functionalized O&M.

1.24.3 Aside from the Rate Smoothing regulatory account, what other regulatory accounts exist with BC Hydro that also have large balances? How are these regulatory accounts proposed to be treated in terms of functionalization and why?

RESPONSE:

The Regulatory Account balances can be found in Exhibit B-1, Appendix E, Schedule RRA 2.2. The table below summarizes those regulatory accounts forecast to have balances greater than $100 million as at F2016 year-end, together with a description of their COS functionalization.

Regulatory Account	COS Functionalization	Rationale
Demand-Side Management	**90 per cent/5 per cent/5 per cent Generation/Transmission/Distribution**	**See Exhibit B-1, section 3.6.6**
First Nations Costs	**Functionalized as incurred (generally to Generation and Transmission)**	**Costs are functionalized consistent with cost causation**
First Nations Provisions	**Functionalized as incurred (generally to Generation and Transmission)**	**Costs are functionalized consistent with cost causation**
Site C	**100 per cent Generation**	**Site C is a generating facility**
Smart Metering & Infrastructure	**100 per cent Distribution**	**SMI costs are metering related and meters are a distribution asset**
Non-Current Pension Cost	**Proportionate to Corporate OMA**	**OMA is a proxy for labour costs**

Regulatory Account	COS Functionalization	Rationale
Environmental Provisions	**Functionalized as incurred (generally to Generation, Transmission, and Distribution)**	**Costs are functionalized consistent with cost causation**
IFRS PP&E	**Proportionate to Corporate OMA**	**Corporate cost associated with accounting policy change**
IFRS Pension	**Proportionate to Corporate OMA**	**Corporate cost associated with accounting policy change**
Rate Smoothing	**Proportionate to revenue requirement functionalization**	**Please refer to BC Hydro's response to BCUC IR 1.24.2**

24.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1, Application, Chapter 3 Cost of Service, pp. 3-20 – 3-21;
Appendix C-2B, Workshop 4 Discussion Guide, p. 5
Functionalization of regulatory accounts

BC Hydro explains that the Rate Smoothing regulatory account, an amount of $122.4 million in the F2016 RRA, was previously assigned to each function proportionate with functionalized O&M.

1.24.4 Please summarize the rationale for the COS Consultant's recommendation that the Rate Smoothing regulatory account now be functionalized as proportionate to the functionalization of the total revenue requirement. Please provide a reference in the COS Consultant's report to the recommendation.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.24.2 with respect to the rationale.

This recommendation was provided orally as part of discussions with the COS Consultants.

24.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1, Application, Chapter 3 Cost of Service, pp. 3-20 – 3-21;
Appendix C-2B, Workshop 4 Discussion Guide, p. 5
Functionalization of regulatory accounts

BC Hydro explains that the Rate Smoothing regulatory account, an amount of $122.4 million in the F2016 RRA, was previously assigned to each function proportionate with functionalized O&M.

1.24.5 Given that Regulatory accounts have historically been lumped together with Deferral accounts which have been functionalized as 100 percent Generation, please explain the first line of Table 3-3, which shows that the "previous O&M method." This line item indicates that the Rate Smoothing regulatory account was previously functionalized to each category of Generation, Transmission, Distribution and Customer Care. Please clarify.

RESPONSE:

Historically, Regulatory account net additions have been functionalized together with Deferral accounts. However, the Rate Smoothing Account only records positive or negative recoveries. The amount related to Rate Smoothing is therefore included in current year corporate OMA and this net amount has been functionalized as a single amount. This is what is shown in Table 3-3 of Exhibit B-1.

24.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1, Application, Chapter 3 Cost of Service, pp. 3-20 – 3-21;
Appendix C-2B, Workshop 4 Discussion Guide, p. 5
Functionalization of regulatory accounts

BC Hydro explains that the Rate Smoothing regulatory account, an amount of $122.4 million in the F2016 RRA, was previously assigned to each function proportionate with functionalized O&M.

1.24.6 In Table 3-3, using the COS Consultant's recommended method increases the functionalization to Generation, while reducing the functionalization to Transmission, Distribution and Customer Care. Which customer classes will most likely be impacted by the higher proportional functionalization to Generation costs? Please discuss.

RESPONSE:

The LGS and Transmission Service rate classes are assigned a greater proportion of costs that are functionalized as Generation than those that are functionalized as Transmission, Distribution, and Customer Care. Transmission, Distribution, and Customer Care costs are primarily allocated by peak demand and customer count allocators, thus rate classes with large users with flatter load profiles (i.e., LGS and Transmission customers) would be assigned a smaller proportion of these costs.

Rate Class	Generation F2016 Per Cent Allocation	Transmission, Distribution, and Customer Care F2016 Per Cent Allocation
Residential	**38.2**	**56.4**
SGS	**7.1**	**9.8**
MGS	**6.5**	**7.5**
LGS	**20.5**	**16.0**
Irrigation	**0.1**	**0.2**
BC Hydro owned Street Lighting	**0.1**	**0.5**
Customer owned Street Lighting	**0.4**	**0.4**
Transmission	**27.1**	**9.2**

25.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Sections 3.7.1 and 3.7.3, pp. 3-23 to 3-26; Appendix C-2A;
Cost of Service Methodology Review (leidos report), and Workshop 2 Discussion Paper; Appendix C-2B, Workshop 4 Discussion Guide, pp. 5 to 7; and Workshop 4 Consideration Memo, pp. 9–12
Classification of Heritage hydro generation

On page 8 of the Workshop 2 Discussion Paper/Strawman Proposal (in Appendix C-2A), BC Hydro says in Table 2, in the 'Cons' for Option 1, that Option 1 "…implies that IPPs, net imports and hydroelectric generation should be treated with a load factor approach because all these sources serve load. If confirmed, this may overestimate the demand contribution of these resources."

Footnote 137 on page 3-24 of the Application states: "Given that BC Hydro proposes to classify IPPs separately from Heritage hydroelectric…it is appropriate to adjust the load factor calculation to remove the impact of IPPs serving load. System load factor is calculated based on loads almost entirely served by Heritage hydroelectric supply."

Page 3-26 of the Application states that BC Hydro's preferred IPP classification is the "Value of Capacity" option, which results in a 93 percent energy and 7 percent demand classification.

1.25.1 With respect to the statement that: "…it is appropriate to adjust the load factor calculation to remove the impact of IPPs serving load," please describe more precisely how the load factor calculation is adjusted to remove the impact of IPPs.

RESPONSE:

The IPP adjustment to the load factor calculation is described on Slide 13 of the Workshop 4 presentation which is found in Appendix C-2B of Exhibit B-1. The adjustment is reproduced below along with references to the inputs used in the calculation:

F2016	Option 1A Include Load Served by IPP Supply	Option 1B Exclude Load Served by IPP Supply
Load Factor (Energy %)	61	55
Energy (GWh)	58,062[1]	58,062 – 12,002[2] = 46,060
Capacity (MW)	10,813[3]	10,813 – 1,272[4] = 9,541

[1] **F2016 energy Load forecast after DSM, from the 2013 Integrated Resource Plan, Appendix 9A, Table 3: BRP without LNG – Energy.**
[2] **IPPs and Long Term Commitments, F2016 Plan from the F2015-F2016 RRA, Schedule 4.0, Line 29.**
[3] **F2016 capacity load forecast after DSM, from the 2013 Integrated Resource Plan, Appendix 9A, Table 3: BRP without LNG – Capacity.**
[4] **Estimated capacity associated with the 12,002 GWh of energy from IPPs and Long Term Commitments.**

25.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Sections 3.7.1 and 3.7.3, pp. 3-23 to 3-26; Appendix C-2A;
Cost of Service Methodology Review (leidos report), and Workshop 2 Discussion Paper; Appendix C-2B, Workshop 4 Discussion Guide, pp. 5 to 7; and Workshop 4 Consideration Memo, pp. 9–12
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Footnote 137 on page 3-24 of the Application states: "Given that BC Hydro proposes to classify IPPs separately from Heritage hydroelectric…it is appropriate to adjust the load factor calculation to remove the impact of IPPs serving load. System load factor is calculated based on loads almost entirely served by Heritage hydroelectric supply."

Page 3-26 of the Application states that BC Hydro's preferred IPP classification is the "Value of Capacity" option, which results in a 93 percent energy and 7 percent demand classification.

1.25.1.1 Similarly, for the related remark that system load factor is calculated based on loads almost entirely served by Heritage hydroelectric supply, please explain how the load factor is calculated to exclude load that is not served by Heritage hydroelectric supply.

RESPONSE:

The only adjustment applied to the load factor calculation was to remove IPP supply. On slide 13 of the Workshop 4 presentation, Appendix C-2B of Exhibit B-1 BC Hydro stated "since IPP costs are classified separately from hydroelectric, load served by IPPs can be excluded from the load factor calculation. The result is a load factor calculation based on load (almost entirely) served by hydroelectric."

BC Hydro considered making additional adjustments to the calculation but determined that other energy or capacity sources, such as Heritage thermal resources (approximately 300 GWh in F2016), were too small to meaningfully affect the calculation.

25.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Sections 3.7.1 and 3.7.3, pp. 3-23 to 3-26; Appendix C-2A;
Cost of Service Methodology Review (leidos report), and Workshop 2 Discussion Paper; Appendix C-2B, Workshop 4 Discussion Guide, pp. 5 to 7; and Workshop 4 Consideration Memo, pp. 9–12
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Page 3-26 of the Application states that BC Hydro's preferred IPP classification is the "Value of Capacity" option, which results in a 93 percent energy and 7 percent demand classification.

1.25.2 Does the adoption of a Value of Capacity option reduce or eliminate the concern raised in Table 2 of the Workshop 2 Discussion Paper (page 8) that a load factor approach to classifying IPPs could result in an overestimate of the demand contribution of these resources? If so, to what extent?

RESPONSE:

Yes, a number of the IPP classification options, including the Value of Capacity Option, can reduce or eliminate the concern that a load factor approach to classify IPPs could result in an overestimate of the demand contribution of these resources. Using the system load factor (i.e., 60 per cent) to classify IPPs implies that approximately 40 per cent of IPP supply is demand-related with the balance energy-related. This demand related estimate significantly overstates the dependable capacity contribution of IPPs. A similar energy to capacity ratio calculated by dividing the annual energy contribution of IPP resources by their capacity contribution planned on for serving peak demand, as shown in the IRP, would be over 100 per cent, implying that most of the IPP resources are energy related. This equation and resulting values from the IRP for F2017 are shown below.

$$\boldsymbol{IPP\ Energy\ to\ Capacity\ Ratio} = \frac{\boldsymbol{Annual\ Firm\ Energy\ from\ IPPs\ [MWh]}}{(\boldsymbol{IPP\ ELCC\ and\ Dep\ Cap\ [MW]}) * \boldsymbol{8760\ hrs}}$$

	Annual Firm Energy (GWh)[a]	**Dependable Capacity & Effective Load Carrying Capability (MW)[b]**	**IPP Energy to Capacity Ratio[1] (%)**
Sum of All IPPs (F2017)	**15,258**	**1,443**	**121**

[a] **Reference: 2013 IRP Appendix 9A Table 3**

[b] **Reference: 2013 IRP Appendix 9A Table 4**

[1] This ratio is a modified version of a capacity factor calculation except dependable / ELCC capacity (which is counted on in the IRP) is used in the denominator rather than installed capacity.

25.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Sections 3.7.1 and 3.7.3, pp. 3-23 to 3-26; Appendix C-2A;
Cost of Service Methodology Review (leidos report), and Workshop 2 Discussion Paper; Appendix C-2B, Workshop 4 Discussion Guide, pp. 5 to 7; and Workshop 4 Consideration Memo, pp. 9–12
Classification of Heritage hydro generation

On page 8 of the Workshop 2 Discussion Paper/Strawman Proposal (in Appendix C-2A), BC Hydro says in Table 2, in the 'Cons' for Option 1, that Option 1 "…implies that IPPs, net imports and hydroelectric generation should be treated with a load factor approach because all these sources serve load. If confirmed, this may overestimate the demand contribution of these resources."

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Page 3-26 of the Application states that BC Hydro's preferred IPP classification is the "Value of Capacity" option, which results in a 93 percent energy and 7 percent demand classification.

1.25.3 Bullet 2 on page 6 of the Workshop 4 Discussion Guide (Appendix C-2B) states that the capacity factor calculation can be variable year over year because of the addition of hydroelectric generating capacity. Completion of Mica Units 5 and 6 in F2016 increases generation capacity by more than 800 MW and decreases the system capacity factor.

1.25.3.1 Is this also a factor in favour of the plant capacity approach, to the extent that the plant capacity factor approach recognizes specific expenditures incurred in order to meet peak load, whereas the load factor approach does not? Why or why not?

RESPONSE:

Yes, BC Hydro agrees that the plant capacity factor approach incorporates generation cost information in the classification calculation while the load factor approach does not. The capacity factor approach reflects changes in BC Hydro's generation mix while the load factor approach does not. For example, if BC Hydro was primarily building generation resources that provide capacity but little or no incremental energy, the capacity factor calculation would reflect a higher proportion of demand-related costs in the generation system while the load factor calculation would not.

25.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Sections 3.7.1 and 3.7.3, pp. 3-23 to 3-26; Appendix C-2A;
Cost of Service Methodology Review (leidos report), and Workshop 2 Discussion Paper; Appendix C-2B, Workshop 4 Discussion Guide, pp. 5 to 7; and Workshop 4 Consideration Memo, pp. 9–12
Classification of Heritage hydro generation

The last bullet on page 3-23 of the Application describes the plant capacity factor approach as: "A plant capacity factor approach (i.e., ratio of average plant load to nameplate plant capacity) that sub-functionalizes hydro generating facilities in service and O&M costs by individual plant or groups of plants and then uses corresponding plant capacity factors to classify hydro plant and O&M costs, excluding water costs."

1.25.4 Using the example given in bullet 2 on page 6 of the Workshop 4 Discussion Guide (Appendix C-2B) that completion of Mica Units 5 and 6 in F2016 increases generation capacity by more than 800 MW and decreases the system capacity factor, please describe in more detail how the completion of Mica Units 5 and 6 would decrease the system capacity factor.

RESPONSE:

The impact of Mica Units 5 and 6 on the system capacity factor calculation is shown below.

	Calculation of System Capacity Factor	
	Without Additional Mica Units	**With Additional Mica Units**
Hydroelectric System Energy	**44,500 GWh**	**46,900 GWh**
Hydroelectric System Capacity	**10,927 MW**	**11,844 MW**
System Capacity Factor	**= 46.5%** **= (46,700,000 MWh)** **(10,927 MW * 8760 hours)**	**= 45.2%** **= (46,900,000 MWh)** **(11,844 MW * 8760 hours)**

25.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Sections 3.7.1 and 3.7.3, pp. 3-23 to 3-26; Appendix C-2A;
Cost of Service Methodology Review (leidos report), and Workshop 2 Discussion Paper; Appendix C-2B, Workshop 4 Discussion Guide, pp. 5 to 7; and Workshop 4 Consideration Memo, pp. 9–12
Classification of Heritage hydro generation

Bullet 4 on page 6 of the Workshop 4 Discussion Guide says that the load factor approach has jurisdictional support (e.g, Newfoundland Power, Idaho Power, Avista).

On pages 4-1 to 4-3 of its report, leidos uses the results of its jurisdictional review to support its recommendation that BC Hydro consider using either a system load factor approach or a plant capacity factor approach to classify hydro costs, excluding water rental costs. Table C-1 in Appendix C of the leidos report confirms the use of the system load factor method by Newfoundland Power, Idaho Power and Avista-Washington.

1.25.5 It is not evident that any of the surveyed utilities shown in Table C-1 use a plant capacity approach, unless the Peak Credit method is essentially similar to the plant capacity approach. Is the Peak Credit method fundamentally the same as the plant capacity approach? If not, what is the jurisdictional support for the recommendation that BC Hydro consider the plant capacity approach?

RESPONSE:

None of the utilities shown in Table C-1 (page 85 of 439) of the COS Methodology Review (copy at Appendix C-2A of Exhibit B-1) specifically use the plant capacity factor approach (i.e., ratio of average plant load to nameplate plant capacity) for classifying hydro resources. However, both system load factor and plant capacity approaches inherently acknowledge that hydro resources are used for both baseload and peaking purposes, with the amount classified as demand-related being attributable to usage for peaking or capacity purposes and the costs classified as energy-related being attributable to usage for baseload or energy purposes.

25.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Sections 3.7.1 and 3.7.3, pp. 3-23 to 3-26; Appendix C-2A;
Cost of Service Methodology Review (leidos report), and Workshop 2 Discussion Paper; Appendix C-2B, Workshop 4 Discussion Guide, pp. 5 to 7; and Workshop 4 Consideration Memo, pp. 9–12
Classification of Heritage hydro generation

Bullet 4 on page 6 of the Workshop 4 Discussion Guide says that the load factor approach has jurisdictional support (e.g, Newfoundland Power, Idaho Power, Avista).

On pages 4-1 to 4-3 of its report, leidos uses the results of its jurisdictional review to support its recommendation that BC Hydro consider using either a system load factor approach or a plant capacity factor approach to classify hydro costs, excluding water rental costs. Table C-1 in Appendix C of the leidos report confirms the use of the system load factor method by Newfoundland Power, Idaho Power and Avista-Washington.

1.25.6 Did leidos, in its jurisdictional review, also review the decisions of the relevant regulatory bodies with regard to their reasons for accepting or rejecting either the system load factor approach or the plant capacity factor approach? If they did, or if BC Hydro has separately reviewed them, please summarize the relevant findings and provide citations (or links) to the original decisions.

RESPONSE:

Yes, the COS Consultants reviewed the decisions of the relevant regulatory bodies with regard to their reasons for accepting or rejecting either the system load factor approach or the plant capacity factor approach, as follows.

<u>Avista Corporation-Washington</u>

The COS Consultants reviewed Avista Corporation-Washington's filing in Docket No. UE-120436. Links to the Final Order 9 and associated multiparty settlement stipulation for Docket No. UE-120436 are as follows:

http://www.wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/a064603d434691b388257ae000715620!OpenDocument.

http://www.wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/c672dec85ad74eab88257ae00071560c!OpenDocument.

For settlement purposes in Docket No. UE-120436, the parties agreed to a uniform percentage of revenue increase for each class for purposes of spreading the revised

electric revenue requirement. The COS methodology was not addressed in the final order or settlement stipulation.

Avista Corporation-Washington also used the load factor approach for classifying hydro resources in Docket No. UE-140188. The link to the Final Order 5 and settlement stipulation in Docket No. UE-140188 is as follows:

http://www.utc.wa.gov/_layouts/CasesPublicWebsite/GetDocument.ashx?docID=1049&year=2014&docketNumber=140188

For settlement purposes in Docket No. UE-140188, the parties again agreed to a uniform percentage of revenue increase for each class for purposes of spreading the revised electric revenue requirement. The COS methodology was not addressed in the settlement stipulation or final order.

Idaho Power Company-Idaho

For purposes of the jurisdictional survey, the COS Consultants reviewed Idaho Power's filing in Case No. IPC-E-11-08. The link to the Final Order No. 32426 is as follows:

http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1108/ordnotc/20111230FINAL_ORDER_NO_32426.PDF

The rates approved by the Idaho Public Utilities Commission were part of a stipulation of settlement. The signing parties agreed that the revised annual revenue requirement would be recovered by increasing the rates for each customer class and special contract customers by a uniform percentage instead of using the Idaho Power-Idaho's original proposal. The parties also agreed that the proposed COS study was not binding on the signing parties in future cases.

Newfoundland Power

For purposes of the jurisdictional survey, the COS Consultants reviewed Newfoundland Power's 2013/2014 General Rate Application. The links to the Final Order PU3-13 and settlement agreement are as follows:

http://www.pub.nl.ca/orders/order2013/pu/pu3-2013.pdf

http://www.pub.nf.ca/applications/NP2013GRA/index.htm

For settlement purposes in Newfoundland Power's 2013/2014 General Rate Application, the parties agreed that in relation to rate design and rate structure that the rates would be based on Newfoundland Power's proposal to vary the rate increase by customer class so cost recovery for each class is within the target R/C ratios of 90 per cent to 110 per cent. The COS methodology was not addressed in the final order or the settlement agreement.

25.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Sections 3.7.1 and 3.7.3, pp. 3-23 to 3-26; Appendix C-2A;
Cost of Service Methodology Review (leidos report), and Workshop 2 Discussion Paper; Appendix C-2B, Workshop 4 Discussion Guide, pp. 5 to 7; and Workshop 4 Consideration Memo, pp. 9–12
Classification of Heritage hydro generation

Bullet 4 on page 6 of the Workshop 4 Discussion Guide says that the load factor approach has jurisdictional support (e.g, Newfoundland Power, Idaho Power, Avista).

On pages 4-1 to 4-3 of its report, leidos uses the results of its jurisdictional review to support its recommendation that BC Hydro consider using either a system load factor approach or a plant capacity factor approach to classify hydro costs, excluding water rental costs. Table C-1 in Appendix C of the leidos report confirms the use of the system load factor method by Newfoundland Power, Idaho Power and Avista-Washington.

1.25.7 In footnote 3 to Table C-1, leidos says that Avista Corporation – Idaho indicated that a system load factor approach to classification would be preferable, but to potentially limit the number of issues in their case, Avista used the prior Peak Credit method in the cost of service study. Can leidos provide the reasons why Avista – Idaho would prefer a system load factor approach?

RESPONSE:

The following are the reasons Avista Corporation-Idaho gave for favoring the load factor method over the peak credit method:

- **Load factor method is tied to the company's actual use of the system in the test year;**
- **Actual load factor represents current use of the system vs. historical replacement cost analysis which is based on vintage investments;**
- **Load factor is a less complicated single ratio applied to all production costs versus multiple ratios, weight dependent on each cost item's relationship to plant investment;**
- **With the load factor method, overall weighted demand/energy relationship stays the same when power costs are updated – not impacted by swings in the cost of fuel, unlike prior method; and**
- **Demand/energy ratios under the load factor method will be more consistent over time versus the prior method.**

26.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Appendix C-2B Workshop 4 Discussion Guide, p. 9
Classification of Heritage Thermal Generation

On page 9 of the Workshop 4 Discussion Guide (Appendix C-2B), BC Hydro proposes to classify the Burrard Thermal Generating Station's O&M and capital costs as 100 percent demand, and its associated fuel costs as 100 percent energy.

1.26.1 Since BC Hydro cannot rely on Burrard for firm energy and will continue to use Burrard for voltage support, would it be more consistent to treat all of Burrard's costs, including fuel, as 100 percent demand? Why or why not?

RESPONSE:

BC Hydro notes that pursuant to sections 3(5), 6(2) and 13 of the *CEA*, BC Hydro cannot rely on Burrard for either firm energy or dependable capacity. Given that Burrard is restricted to providing transmission voltage support, the fuel costs are minor.

Classifying the fuel costs as 100 per cent demand would result in them being allocated to customers based on 4CP even though the fuel costs are incurred throughout the year. Fuel costs, including those associated with peaking plants, are usually classified as energy in COS studies.

Please refer to BC Hydro's responses to AMPC IR 1.5.3 which describes the operation of Burrard and CEC IR 1.27.2 which contains data showing when the plant is being operated.

26.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Appendix C-2B Workshop 4 Discussion Guide, p. 9
Classification of Heritage Thermal Generation

On page 9 of the Workshop 4 Discussion Guide (Appendix C-2B), BC Hydro proposes to classify the Burrard Thermal Generating Station's O&M and capital costs as 100 percent demand, and its associated fuel costs as 100 percent energy.

1.26.1.1 What would be the impact on R/C ratios of the treating all Burrard costs as 100 percent demand?

RESPONSE:

Under the proposed COS methodology, the R/C ratio impact of treating Burrard costs as 100 per cent demand is shown in the table below.

Rate Class	Change to R/C Ratio
Residential	**+0.10**
SGS	**+0.01**
MGS	**-0.01**
LGS	**-0.07**
Irrigation	**-0.40**
Street Lighting	**+0.16**
Transmission	**-0.19**

27.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Sections 3.7.3, p. 3-26; Appendix C-2A; Workshop 2 Discussion Paper, Attachment 4 and COS Methodology Review Presentation, slide 43; and Appendix C-2B, Workshop 4 Consideration Memo, p. 8

Classification of Generation – independent power producers

Page 3-26 of the Application states that BC Hydro's preferred IPP classification is the Value of Capacity option, which results in a 93 percent energy and 7 percent demand classification.

Attachment 4 to the Workshop 2 Consideration Memo (Appendix C-2a) notes on page 1 that as of April 1, 2014, BC Hydro had 86 Electricity Purchase Agreements (EPAs) with in-service IPP projects and a further 41 for under-development IPP projects.

Attachment 4 provides contract information for 4 EPAs with fixed cost components and discusses the energy and capacity contributions of the 4 EPAs. It says that classifying EPA purchases on the basis of the fixed and variable components would produce counter intuitive results.

Slide 43 of the COS Methodology Review Presentation (Appendix C-2A) shows the percent classified as demand for IPPs using the Value of Capacity method.

On page 8 of the Workshop 4 Consideration Memo BC Hydro agrees that its preferred Option 2 ('Value of Capacity') for classifying IPP costs is based on the 2013 IRP's Long-Run Marginal Cost for energy (upper end of $100/MWh) and for Generation-related capacity ($55/kW-year) in $2013.

1.27.1 Please provide a table or calculation that shows the Value of Capacity derivation of the IPP classification of 93 percent energy and 7 percent demand for IPP contracts.

RESPONSE:

The following two equations were used in the "Value of Capacity" calculation in classifying IPP costs:

Value of Capacity ($) = IPP Capacity Contribution (kW) x Capacity LRMC ($/kW-year)

$$\%\ \boldsymbol{of\ IPP\ Costs\ classified\ as\ demand} = \frac{\boldsymbol{Value\ of\ Capacity}\ (\$)}{\boldsymbol{Total\ IPP\ Cost}\ (\$)}$$

The generation-related capacity LRMC is based on the Rev 6 UCC from the 2013-IRP ($50 to $55/kW-year in $ F2013CDN). The upper end of the range was used in this calculation and was inflated to $56.61/kW-year $ F2016CDN using the B.C. Consumer Price Index (CPI) to be in the same year $ as the IPP costs used in the cost of service analysis. The following table shows the numbers by resource types:

	IPP Capacity Contribution F2016 (MW)	Total IPP Cost ($ million F2016CDN)	Percentage of IPP Costs Classified as Demand (%)
Alcan	153	63	14
Storage Hydro	156	106	8
Island Generation	275	59	26
McMahon	108	51	12
Wind	115	140	5
Biomass & Waste Heat	423	280	9
Run of River	129	435	2
Sum of All IPPs	1359	1134	7

28.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.7.4, pp. 3-26 and 3-27 Classification of Generation-related DSM

BC Hydro states that its rationale for functionalizing 90 percent of DSM to Generation is that "…DSM expenditures are primarily incurred to avoid generation-related costs, which also avoids the classification of those same costs into energy and demand. Therefore, to be consistent with the rationale for functionalizing DSM costs to generation, BC Hydro believes that the classification of Generation-related DSM costs should mirror the classification of overall Generation costs in the revenue requirement."

1.28.1 Does this mean that it mirrors the classification of Heritage hydro Generation-related costs, which make up the bulk of the costs, or that it reflects a weighted average of all Generation-related costs, including thermal and IPPs, or something different than either of those alternatives? Please explain, including references to the sheets in the COS model where the treatment of Generation DSM related costs is shown.

RESPONSE:

The classification of DSM amortization expense is included with total Generation Depreciation and Amortization. These have been classified consistent with the classification for Heritage hydro generation-related costs.

In the COS model, the DSM amount functionalized to Generation is shown on Schedule 1.0 in row 64 (Excel model, Appendix E, Exhibit B-1). The total Depreciation and Amortization functionalized to Generation is shown in row 65 of Schedule 1.0 and the classification for this amount is shown in row 32 of Schedule 2.0.

29.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.7.7, pp. 3-27 to 3-29; and Appendix C-2B, Workshop 4 Discussion Guide, p. 2 Table 1, and pp. 13-14; and Appendix C-2A; Cost of Service Methodology Review (leidos report), pp. 4-4 to 4-6 Classification of Distribution Costs

BC Hydro says on page 3-28 of the Application that: "Generally there are three approaches to classifying distribution costs: (1) minimum system; (2) zero-intercept; and (3) the use of professional judgment to separate demand-related and customer-related distribution costs." BC Hydro further notes that the COS consultants recommended approach (3). On page 3-29, BC Hydro says that it proposes to classify Distribution costs based on Table 1 of the Workshop 4 Discussion Guide (in Appendix C-2B), which appears to be based on the adoption of approach (3). Table 1 of the Workshop 4 Discussion Guide separates and classifies distribution cost categories under the Preferred Option and an Alternative for Sensitivity analysis.

1.29.1 The cell in Table 1 showing the Alternative for Sensitivity Analysis for distribution indicates a 100 percent demand classification for secondary/services and a 100 percent customer classification for services. Is it correct to assume that this should show a 100 percent demand classification for the secondary portion and a 100 percent customer classification for services?

RESPONSE:

Yes, Table 1 of the Workshop 4 Discussion Guide (Appendix C-2A, Exhibit B-1) should show a 100 per cent demand-related classification for secondary and a 100 per cent customer-related classification for services as shown in the Table below, which accurately reflects BC Hydro's classification of asset categories. The only difference between the preferred option in the table and the alternative for sensitivity analysis is the treatment of transformers.

Secondary/Services asset category (split 50% secondary; 50% services)	BC Hydro preferred option	Alternative for sensitivity Analysis
Secondary Portion	**100% demand-related**	**100% demand-related**
Services Portion	**100% customer-related**	**100% customer-related**

29.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.7.7, pp. 3-27 to 3-29; and Appendix C-2B, Workshop 4 Discussion Guide, p. 2 Table 1, and pp. 13-14; and Appendix C-2A; Cost of Service Methodology Review (leidos report), pp. 4-4 to 4-6 Classification of Distribution Costs

BC Hydro says on page 3-28 of the Application that: "Generally there are three approaches to classifying distribution costs: (1) minimum system; (2) zero-intercept; and (3) the use of professional judgment to separate demand-related and customer-related distribution costs." BC Hydro further notes that the COS consultants recommended approach (3). On page 3-29, BC Hydro says that it proposes to classify Distribution costs based on Table 1 of the Workshop 4 Discussion Guide (in Appendix C-2B), which appears to be based on the adoption of approach (3). Table 1 of the Workshop 4 Discussion Guide separates and classifies distribution cost categories under the Preferred Option and an Alternative for Sensitivity analysis.

1.29.2 If the assumption in the above question is correct, then does BC Hydro accept that the table below accurately reflects the classifications of the Distribution asset categories shown in Table 1 of the Workshop 4 Discussion Guide? If not, please provide a corrected copy of the table.

Asset Category	BC Hydro Preferred Option	Alternative for Sensitivity Analysis
Substations and primary system	100% Demand	100% demand
Transformers	50% demand; 50% customer	100% demand
Secondary/services asset category (split 50% secondary; 50% services) • Secondary Portion • Service Portion		
	100% demand	100% demand
	100% customer	100% customer
Meters	100% customer	100% customer

RESPONSE:

The assumption in the IR is correct. Please refer to BC Hydro's response to BCUC IR 1.29.1 for a corrected table showing the classification of Secondary/Services.

29.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.7.7, pp. 3-27 to 3-29; and Appendix C-2B, Workshop 4 Discussion Guide, p. 2 Table 1, and pp. 13-14; and Appendix C-2A; Cost of Service Methodology Review (leidos report), pp. 4-4 to 4-6 Classification of Distribution Costs

BC Hydro says on page 3-28 of the Application that: "Generally there are three approaches to classifying distribution costs: (1) minimum system; (2) zero-intercept; and (3) the use of professional judgment to separate demand-related and customer-related distribution costs." BC Hydro further notes that the COS consultants recommended approach (3). On page 3-29, BC Hydro says that it proposes to classify Distribution costs based on Table 1 of the Workshop 4 Discussion Guide (in Appendix C-2B), which appears to be based on the adoption of approach (3). Table 1 of the Workshop 4 Discussion Guide separates and classifies distribution cost categories under the Preferred Option and an Alternative for Sensitivity analysis.

1.29.2.1 Is it correct to conclude that the only difference between BC Hydro's Preferred Option and the Alternative for Sensitivity Analysis is in the classification of transformers? If not, why not?

RESPONSE:

Yes. Please refer to BC Hydro's response to BCUC IR 1.29.1.

29.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.7.7, pp. 3-27 to 3-29; and Appendix C-2B, Workshop 4 Discussion Guide, p. 2 Table 1, and pp. 13-14; and Appendix C-2A; Cost of Service Methodology Review (leidos report), pp. 4-4 to 4-6
Classification of Distribution Costs

On page 22 of the Workshop 4 Consideration memo (Appendix C-2B), BC Hydro says that the 50 percent demand / 50 percent customer classification should not impact the total costs allocated to each rate class because the direct assignment approach will be used for assigning costs among rate classes.

1.29.3 It would seem reasonable to conclude that a result of the direct assignment of transformer costs is that the percentage of transformer costs classified as customer or demand will not impact the overall costs assigned to a customer class. However, Table 7 on page 14 of the Workshop 4 Discussion Guide indicates that there is a difference in the R/C ratios under BC Hydro's Preferred Option 1 and Option 2. Please explain.

RESPONSE:

Table 7 on page 14 of the Workshop 4 Discussion Guide compares BC Hydro's proposed sub-functionalization methodology (Option 1) and an alternative method (Option 2) for classification of Distribution costs. Transformer costs account for less than 15 per cent of the total costs impacted by the two methodologies being compared.

It is correct to conclude that a result of the direct assignment of transformer costs is that the percentage of transformer costs classified as customer or demand will not impact the overall costs assigned to a customer class. In the Workshop 4 consideration memo (page 102 of 205 of Appendix C-2B, Exhibit B-1), BC Hydro was referring to its overall categorization of transformer costs as demand- or customer-related in the summary table provided in Schedule 4.1 of Appendix E. Since transformer costs are direct assigned, for allocation purposes they are not subject to classification as either demand or customer-related in the classification methodology.

For rate design purposes, it is necessary to categorize costs into the categories of energy, demand, and customer to recover costs through appropriate billing determinants. Since "transformer" is not a unit for which a rate per unit can readily be developed, these costs are divided between energy and demand for purposes of categorization for rate design, but not for the purposes of allocation. The resulting R/C ratios from this sensitivity were illustrative and did not guide any F2016 COS related proposal.

30.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.8.4, pp. 3-33 to 3-34; Appendix C-2C, Stakeholder Feedback, p. 63 of 79, APMC March 16, 2015 Comments
Allocation of distribution demand-related costs

BC Hydro is using 1NCP (non-coincidental peak) based on average rate class load profiles for five years to assign Distribution demand related costs. The APMC, in its March 16, 2015 comments says that:

The demand determinants used by BC Hydro are based on a 5-year average, and the energy determinants are based inconsistently on a single year F2016 forecast. Demand and energy allocators should both be determined as a 5-year average of actual recorded data and not based on forecasts, particularly for a single year such as F2016.

1.30.1 Please confirm that BC Hydro's COS model energy allocator is based on an F2016 energy forecast, and that the Distribution demand allocator is based on average rate class load profiles for 5 years (F2010 to F2014).

RESPONSE:

Yes, the energy allocator in the COS study is based on F2016. BC Hydro considered AMPC's suggestion to base the F2016 COS study's energy allocator on a five year average of energy sales but rejected it because it would lead to a mismatch between costs and revenues in the F2016 COS study.

BC Hydro estimates that approximately 85 per cent of its revenues are derived from energy charges. Therefore, using a five year average of energy sales to allocate energy costs implies that a five-year average of revenues should be used as well in the COS study. This in turn suggests that a five year average of costs should be used when calculating R/C ratios. This would complicate the COS study and would be less meaningful if costs have changed significantly during the five year period being considered.

The use of a five year average can meaningfully impact class R/C ratios unless adjustments for revenue are also made. To illustrate this point, consider the SGS class where almost 95 per cent of class revenue is directly related to the energy charge. The SGS class has forecast F2016 purchases of 3,702 GWh, which are lower than any year in the F2010 to F2014 period. Had a five-year average of SGS energy sales been used in the F2016 COS (3,918 GWh), without a corresponding adjustment to revenue, the SGS class would have been allocated an additional $16 million of energy-related cost and the class R/C ratio would experience a

meaningful five percentage point drop from 112 per cent to 107 per cent as shown in the table below.

	Energy Allocation Methodology	
	F2016 Energy	**Five-Year Average of Energy**
Energy-related costs assigned to the SGS class ($ million)	**140**	**156**
Total costs assigned to the class ($ million)	**368**	**384**
F2016 revenue ($ million)	**412**	**412**
F2016 R/C ratio (%)	**112**	**107**

In addition, there is little jurisdictional support for using a five year average for energy allocation. According to the COS Consultants, other utilities have used multi-year averages to allocate COS study energy costs in cases where there is significant variation in annual energy costs, such as thermal generation-related fuel costs. This is not applicable to BC Hydro since the $/MWh costs of hydroelectric generation, including water rentals, are fairly steady year over year.

BC Hydro believes a five year average is appropriate for the 4CP/NCP allocators and notes:

- **There is more year over year variability in 4CP/NCP class loads than there is in class energy consumption; and**
- **Demand charge revenue accounts for less than 15 per cent of BC Hydro's total revenue so, unlike a five-year average of energy use, there is no need to adjust the F2016 revenue forecast.**

30.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.8.4, pp. 3-33 to 3-34; Appendix C-2C, Stakeholder Feedback, p. 63 of 79, APMC March 16, 2015 Comments
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BC Hydro is using 1NCP (non-coincidental peak) based on average rate class load profiles for five years to assign Distribution demand related costs. The APMC, in its March 16, 2015 comments says that:

The demand determinants used by BC Hydro are based on a 5-year average, and the energy determinants are based inconsistently on a single year F2016 forecast. Demand and energy allocators should both be determined as a 5-year average of actual recorded data and not based on forecasts, particularly for a single year such as F2016.

1.30.1 Please confirm that BC Hydro's COS model energy allocator is based on an F2016 energy forecast, and that the Distribution demand allocator is based on average rate class load profiles for 5 years (F2010 to F2014).

1.30.1.1 If no, please clarify which data are used for the energy and demand allocators.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.30.1.

30.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.8.4, pp. 3-33 to 3-34; Appendix C-2C, Stakeholder Feedback, p. 63 of 79, APMC March 16, 2015 Comments
Allocation of distribution demand-related costs

BC Hydro is using 1NCP (non-coincidental peak) based on average rate class load profiles for five years to assign Distribution demand related costs. The APMC, in its March 16, 2015 comments says that:

The demand determinants used by BC Hydro are based on a 5-year average, and the energy determinants are based inconsistently on a single year F2016 forecast. Demand and energy allocators should both be determined as a 5-year average of actual recorded data and not based on forecasts, particularly for a single year such as F2016.

1.30.1 Please confirm that BC Hydro's COS model energy allocator is based on an F2016 energy forecast, and that the Distribution demand allocator is based on average rate class load profiles for 5 years (F2010 to F2014).

1.30.1.2 If yes, would it be preferable, for reasons of consistency and stability of values, to use five year averages for both the energy and demand allocators? Please explain.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.30.1.

31.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.8.4, p. 3-35; Appendix C-2B, Workshop 4 Consideration Memo, p. 24; and Appendix E, 2016 COS Model, Schedules 3.2 and 5.1
Allocation of distribution demand-related costs

In Table 3-5 on page 3-35 of the Application, BC Hydro says that: "Separate NCP allocators are used to allocate distribution demand related costs to primary and secondary distribution customers. The draft model used a single allocator covering all distribution customers."

On page 24 of the Workshop 4 Consideration Memo, BC Hydro says that each rate class is assigned a 1NCP percentage allocator based on its annual peak load as a proportion of the sum of all rate classes annual peak load.

Schedule 3.2 of the COS model (Appendix E) shows that the Distribution Demand Related allocator is NCP; the Distribution Secondary Demand Related allocator is NCP w/o primary. Both of these refer to Schedule 5.1, which has columns for 4 CP, NCP w/o Transmission and NCP w/o Primary.

1.31.1 Please confirm that the NCP and NCP w/o Transmission are 1NCP allocators. If not, please explain.

RESPONSE:

Confirmed.

31.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.8.4, p. 3-35; Appendix C-2B, Workshop 4 Consideration Memo, p. 24; and Appendix E, 2016 COS Model, Schedules 3.2 and 5.1
Allocation of distribution demand-related costs

Reference to Schedule 5.1 indicates that the NCP allocator for Distribution Demand (in Schedule 3.2) is the same as the NCP w/o Transmission in Schedule 5.1. The allocator for Distribution Secondary Demand Related is shown in both Schedule 3.2 and 5.1 as NCP w/o Primary.

1.31.2 Please describe the method of deriving the NCP w/o T and the NCP w/o primary allocators.

RESPONSE:

To derive each rate class's per cent allocator for NCP without Transmission, the rate class's peak demand for the year is divided by the sum of all rate classes' peak demand, excluding Transmission load.

To derive each rate class's percent allocator for NCP without primary, the rate class's peak demand for the year is divided by the sum of all rate classes' peak demand, excluding Transmission load and excluding MGS and LGS customer load connected at primary voltage.

32.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Section 3.8.5, p. 3-34; Appendix C-2B, Workshop 4 Discussion Guide, pp. 14–16, Figure 1 and Table 7 Allocation of customer care costs

BC Hydro allocates customer care costs using a 90/10 weighted allocator between number of customers and revenue by rate class. The Workshop 4 Discussion Guide (pp. 15–16) compares the Customer Care Weighted Allocator method with a more detailed bottom up analysis. On page 3-34 of the Application, BC Hydro refers to the Workshop 4 Discussion Guide and says that Figure 1 demonstrates that the existing 90 percent/10 percent allocator aligns well with a direct allocation of customer costs.

1.32.1 Please elaborate on the pros and cons of the weighted allocator versus the bottom up methods of allocating customer costs. In other words, given that the weighted allocator method and the direct allocation method align well with each other, would it be appropriate to adopt the more direct approach (direct allocation)?

RESPONSE:

BC Hydro concluded that the weighted allocator method was preferable since it yielded a very similar result to the bottom-up method with greater ease of calculation.

Allocation Method	Pros	Cons
Weighted Allocator	**Ease of Calculation** **Reasonable degree of precision, as verified by bottom-up method**	**Perceived lack of precision**
Bottom-up Allocation	**Calculation precision**	**More time-consuming to gather data** **Minimal adjustment to rate class allocators for additional calculation effort**

33.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1 Application, Appendix C-2A, Distribution COS Study, pp. 9 and 10; Appendix C-2C (page 28), Schedule RRA 3.4, line 10
Substation Distribution Asset (SDA) Allocation

On page 10 of the Distribution COS study (Appendix C-2A), BC Hydro says that: "The SDA function revenue requirement is shown in Table 1 above and is $32.8 million in F2010." Schedule RRA 3.4 of the F2016 COS model shows the largest of the Internal Allocations is the SDA Allocation at $148.3 million. Please describe the reason(s) for the difference between the SDA function F2010 revenue requirement of $32.8 million and the F2016 SDA Internal Allocation of $148.3 million.

1.33.1 Table 1 on page 9 of the Distribution COS Study shows that the Internal Allocation of SDA Asset charges, has ranged from $25.3 million in F2007 to $32.8 million in F2010. If the reason for the difference between the F2010 SDA amount and the F2016 internal allocation amount is a result of growth in the SDA, please explain the main reason(s) for such high growth from F2010 to F2016 relative to the F2007 to F2010 period.

RESPONSE:

The internal allocation of SDA charges is found in the F2015-F2016 RRA, Schedule 3.4, line 10. SDA charges increased from $42.8 million in F2011 to $110.2 million in F2012 because of changes in asset classification between distribution and transmission arising from the merging of BCTC and BC Hydro in F2012.

Since F2012, SDA charges have continued to grow, largely because of additional capital assets being added to the distribution system.

34.0 B. CHAPTER 3 – COST OF SERVICE

Reference: Exhibit B-1, Application, Section 3.9 Revenue to Cost Ratios, p. 3-36 Table 3-6; Workshop 2 Consideration Memo, p. 29 Final Study R/C Ratios Filed in the RDA

In the BC Hydro Consideration of Participant Feedback on the June 19, 2014 Workshop No. 2, BC Hydro says on page 29:

BC Hydro plans to propose a 95 percent to 105 per cent R/C ratio range of reasonableness as part of its 2015 RDA. BC Hydro expects SMI-related information will further improve confidence in COS results relative to BC Hydro's 2007 RDA proposed R/C ratio range of reasonableness of 90 per cent to 110 per cent.

As a result of BC Regulation 140/2015 deposited on July 15, 2015 (see Exhibit B-1, page 2-7) which ordered that "the Commission must not set rates for the purposes of changing the R/C ratio for a class of customers," BC Hydro's intended range of reasonableness proposal was not put forward in the 2015 RDA.

Table 3-6 presents the R/C ratios of two different COS study methodologies. It appears that most of the R/C ratios have not changed much from the February 8, 2014 filing based on 2007 RDA Decision except for Residential and SGS.

1.34.1 Please summarize the factors that led to the large reduction in the SGS R/C ratio and the modest increase in Residential R/C ratio in the current filing.

RESPONSE:

Changes in R/C ratios from one period over another are impacted by the interplay of changes in revenues and costs assigned to rate classes. When allocated cost by rate class increases at a faster rate than rate class revenue over the period, R/C ratios will decrease. Similarly, if revenue by rate class decreases at a faster rate than allocated cost over the period, R/C ratios will decrease.

SGS revenue is forecast to increase by 11 per cent in F2016 over F2013, even though overall costs increase by 24 per cent over the same period. With the lower forecast energy use, less proportionate energy cost was assigned to the SGS class. Further, generation energy-related costs have increased relative to generation demand-related costs. However for the F2016 COS, demand allocators were not forecast and demand costs were assigned on historical five-year average basis which may not reflect potential reductions in the class's peak usage in the F2016 period. Thus, on a forecast basis, the proportion of demand costs assigned

to the SGS class did not decrease as much as energy costs. Reduced revenue coupled with a smaller reduction in cost both contribute to the relative reduction in the R/C ratio for the SGS class in F2016 compared to F2013.

Previously, customer count was the only allocator for customer-related distribution costs in BC Hydro's COS study. Under the proposed F2016 COS methodology, these costs are allocated on a more refined basis. While services continue to be allocated using customer count, transformer costs are directly assigned and metering costs are assigned using a weighted metering allocator. Customer count always assigns the greatest proportion of costs to the Residential class because this class accounts for the majority of BC Hydro's customers (> 88 per cent). Reducing the proportion of costs allocated to the Residential class increases the class R/C ratio. In addition, the proportion of distribution cost that is classified as customer-related has fallen from 35 per cent in the 2007 RDA to less than 30 per cent in the F2016 COS study.

Under the proposed F2016 COS methodology, capital lease costs associated with IPPs that were previously functionalized as Customer Care costs have been functionalized as Generation. Customer Care costs are allocated primarily on customer count, which is heavily weighted toward the Residential class. Reducing Customer Care costs by shifting to Generation costs reduces the total cost allocation to the Residential class, thus increasing its R/C ratio.

35.0 C. CHAPTER 4 – RATE CLASS DETERMINATION

Reference: Exhibit B-1, Application, Section 4.3.2.2 Potential Extra Large General Service Class, p. 4-14
Extra large general service (XLGS) Segmentation

On page 4-14, BC Hydro indicates that it commits to undertaking additional engagement with stakeholders who potentially would take service under an LGS Transmission Service Rate (TSR)-like rate, and bringing forward its analysis and proposal as part of RDA Module 2.

1.35.1 BC Hydro is requesting a flat energy rate as default rate for the LGS class in Module 1. If the flat rate is approved in Module 1, would BC Hydro be requesting the TSR-like rate to be an option for the LGS rate class customers under the default flat rate or would the TSR-rate be only available to a segmented group of XLGS customers as default rate? Please discuss.

RESPONSE:

To date, consideration of a potential TSR-like rate has been in the context of:

- **Approval of a flat rate for the LGS class as part of Module 1; and**
- **The potential TSR-like rate as a default rate, contingent on determining also the appropriateness of segmenting the largest LGS customers into a new class for this purpose.**

BC Hydro will consider a potential TSR-like rate including whether it should be default or voluntary, as part of Module 2.

36.0 C. CHAPTER 4 – RATE CLASS DETERMINATION

Reference: Exhibit B-1 Application, Section 4.5 Irrigation rate class, p. 4-23
Irrigation

BC Hydro proposes no changes to the existing Irrigation class. The service RS 1401 is available to customers for electricity use during the Irrigation Season, defined as the period between March 1 and October 31.

1.36.1 Does BC Hydro consider that conservation savings can be targeted from the Irrigation class? Does BC Hydro have information on price sensitivity of irrigation customers? If so, please provide the information. If not, please explain why BC Hydro has not targeted this rate class for conservation savings.

RESPONSE:

The referenced text above concerns the definition of the Irrigation rate class rather than the rate structures for that class. As described in section 1.5.2 of Exhibit B-1, BC Hydro will be addressing Irrigation rate structures as part of Module 2 of the 2015 RDA.

37.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, pp. 5-3 and 5-16;
Appendix C-3B, Evaluation of the RIB report
RIB Conservation Savings

The existing RIB rate is BC Hydro's preferred default Residential rate.

BC Hydro states that the 2013 RIB Evaluation report "concluded that the RIB rate appears to be achieving its overall objective of encouraging conservation through Residential customer response..." BC Hydro also states that the RIB is expected to have delivered approximately 480 GWh/year in cumulative conservation over the first ten years of implementation, which is from October 2008 through F2017 (p. 5-3).

1.37.1 Is the successful delivery of conservation savings the major reason for BC Hydro's preference? Has adverse bill impacts (compared to flat rate) and economically efficiency rate structures been design issues when BC Hydro was selecting its preferred rate design?

RESPONSE:

As illustrated in Table 5-7 of Exhibit B-1, BC Hydro evaluated the RIB rate against all eight Bonbright criteria. Continuing with the RIB rate required little in the way of trade-offs as its performance against the Bonbright criteria was good across the various criteria. In particular, with respect to the Bonbright rate stability criteria (and as described in Table 1-2 of Exhibit B-1) where the default rate is performing as expected and continues to be useful it should not be replaced with a new rate. This is the case for the RIB rate.

BC Hydro also considered the bill impacts associated with the viable alternatives to the RIB rate (three-step rate and flat rate). As described on page 5-23 of Exhibit B-1, moving from the RIB rate to a flat rate would result in high bill impacts for the majority of customers (70 per cent of customers would experience bill impacts above 10 per cent while 41 per cent of customers would experience bill impacts greater than 20 per cent).

37.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, pp. 5-3 and 5-16;
Appendix C-3B, Evaluation of the RIB report
RIB Conservation Savings

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1.37.2 Please discuss the forecast of cumulative conservation for the first ten years of implementation. If available, please provide the annual forecast between F2009 and F2015, comparing to actual conservation achieved. If annual information is unavailable, provide the cumulative forecast and cumulative savings achieved.

RESPONSE:

In summary, the incremental rate structure conservation for each year (incorporated in the DSM Plan) is forecasted by subtracting the incremental natural conservation (computed using an elasticity of -0.05, incorporated in the load forecast before DSM) from the total incremental conservation (using elasticity of -0.1 for RIB rate Step 2 marginal consumption and -0.05 for Step 1 marginal consumption). The Residential conservation forecasting details are discussed in Exhibit B-1, Appendix H-1A, section 3 (page 4). The incremental conservation for each year are summed together to provide cumulative conservation forecasts up to the year of interest.

The 2013 RIB Evaluation Report is the latest evaluation available, and is found at Appendix C-3B of Exhibit B-1. It shows the evaluated (actual) and the reported (forecasted) savings from F2009 to F2012 from Table E.3 (page 109 of 609) of the report. The forecasted savings from F2013 to F2017 are estimated based on the latest available data at the time of the 2015 RDA filing, including the incorporation of F2009 to F2012 evaluation outcomes. They are illustrated below.

	Forecast Cumulative Conservation (GWh/year)	Evaluated Cumulative Conservation using Midpoint of High and Low (GWh/year)	Source
F2008	**Base year; 0 rate structure conservation**		
F2009	**92**	**76**	**Table E.3 of the 2013 RIB Evaluation Report**
F2010	**322**	**224**	

	Forecast Cumulative Conservation (GWh/year)	Evaluated Cumulative Conservation using Midpoint of High and Low (GWh/year)	Source
F2011	**348**	**250**	**(Appendix C-3B)**
F2012	**449**	**309**	
F2013	**351**	**N/A**	**Rate design conservation model for 2015 RDA, which incorporates the F2009 to F2012 evaluation outcomes.**
F2014	**370**		
F2015	**430**		
F2016	**460**		
F2017	**470**		

37.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, pp. 5-3 and 5-16;
Appendix C-3B, Evaluation of the RIB report
RIB Conservation Savings

The existing RIB rate is BC Hydro's preferred default Residential rate.

BC Hydro states that the 2013 RIB Evaluation report "concluded that the RIB rate appears to be achieving its overall objective of encouraging conservation through Residential customer response..." BC Hydro also states that the RIB is expected to have delivered approximately 480 GWh/year in cumulative conservation over the first ten years of implementation, which is from October 2008 through F2017 (p. 5-3).

1.37.3 Can BC Hydro's model be used to determine (ignoring bill impact constraints) the (i) optimum Tier 1 / Tier 2 spread to maximize conservation, or (ii) the optimum Step 1 threshold to maximize conservation? If yes, please provide the optimum levels. If no, please explain the usefulness of the model in identifying conservation benefits from alternative rate designs.

RESPONSE:

From a conservation perspective, BC Hydro believes that conservation would be increased by higher Step 2 prices and by increased customer understanding and awareness of that Step 2 price. However, it is the magnitude of the Step 2 price, rather than the differential, that should be the conservation driver for an informed customer. In other words BC Hydro does not believe there is an optimum Step 1/Step 2 spread that would maximize conservation. Please refer to the Workshop 9a/9b consideration memo, Exhibit B-1, Appendix C-3B, page 369 of 609 which sets out BC Hydro's jurisdictional assessment that the existing RIB rate Step 1/Step 2 differential (which is about 50 per cent) is within the range of differentials for surveyed U.S. and Canadian residential two-step inclining block rates.

As discussed in Workshop 3, BC Hydro's conservation models are not optimization models built to find a single design that yields the highest rate structure conservation. Rather, they are analytical models customized for each rate design that estimates conservation given inputs from various sources, including the rate structures, prices, load forecast, and load shapes. These inputs come from separate and independent models as well.

A sensitivity analysis of alternative Step 1/Step 2 thresholds and the forecasted conservation is shown in Exhibit B-1, Appendix C-3A, page 60 of 184. The outcomes show the bill impacts and conservation outcomes within the threshold range of 635 GWh/month (85 per cent of F2013 median) to 917 GWh/month (F2013 Mean). Generally, within this range, higher thresholds yield higher conservation and more adverse bill impacts. At 917 GWh/month, the analysis shows an increase of 143 GWh/year in conservation relative to status quo, but it also yields bill impacts that exceed the 10 per cent amber signal.

38.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, p. 5-18
Customer responsiveness, awareness, and understanding

BC Hydro indicates that a total of 50 percent of Residential customers appear to be aware of the RIB rate as of February 2012. During Workshop 9a, BC Hydro responded to a BCSEA inquiry as to whether the 50 percent customer awareness could be increased. BC Hydro indicated that an increase in customer awareness would come at a cost.

1.38.1 Presumably, customer awareness has increased since the launch of the RIB rate in 2008. Has BC Hydro monitored this increase in awareness over the last number of years? If so, please comment on the results.

RESPONSE:

BC Hydro has monitored RIB rate awareness over time. Survey results indicate that aided awareness increased from 37 per cent in 2009 to 48 per cent in 2012 and to 55 per cent in 2014. Please refer to Exhibit B-1, Appendix C-3F, page 239 of 348.

38.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, p. 5-18
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1.38.1.1 For those customers who displayed awareness of the RIB rate, please describe the respective percentage shares (e.g., for F2010 and F2014) of those customers who: (a) experienced lower bill impact than flat rate; (b) who experienced higher bill impact that flat rate; and (c) who experienced neutral impact. Please comment if the awareness is related to positive or negative bill impacts.

RESPONSE:

Among the 50 per cent of Residential customers who demonstrated unaided awareness of the RIB rate in February 2012, 71 per cent experienced lower bills in F2012 under the RIB rate than they would have under a flat rate, 24 per cent experienced higher bills under the RIB rate than they would have under a flat rate, and 5 per cent experienced neutral bill impacts, whereby their bill under the RIB rate was within 1 per cent of what their bill would have been under a flat rate.

To answer this IR, BC Hydro analyzed bill impacts in the same fiscal year as when the awareness data was collected. Some of the accounts for which awareness data was available for F2012 were not open in F2010 or F2014. And levels of awareness in F2010 or F2014 could have been different than in F2012.

The analysis was done by linking the responses to the February 2012 survey to survey respondents' electricity consumption data for F2012. Bill impacts were calculated as the difference between the customers' actual bill in F2012 and what their bill would have been in F2012 if they had been billed under the flat rate. The February 2012 survey sample was weighted to be representative of the entire Residential customer population on the RIB rate.

Customers who demonstrated unaided awareness of the RIB rate were more likely to have experienced lower bill impacts under the RIB rate compared to a flat rate, as opposed to higher or neutral bill impacts. BC Hydro does not have information with which to confirm the causal direction of the relationship between RIB rate awareness and bill impacts.

38.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, p. 5-18
Customer responsiveness, awareness, and understanding

BC Hydro indicates that a total of 50 percent of Residential customers appear to be aware of the RIB rate as of February 2012. During Workshop 9a, BC Hydro responded to a BCSEA inquiry as to whether the 50 percent customer awareness could be increased. BC Hydro indicated that an increase in customer awareness would come at a cost.

1.38.2 Please comment on whether this 50 percent awareness is reasonable in BC Hydro's view. What is the basis of comparison? Is BC Hydro aware of the results of comparative rates for utilities in other jurisdictions?

RESPONSE:

BC Hydro believes that 50 per cent awareness is reasonable given past outreach efforts[1] and the period of time that the RIB rate has been in effect for Residential customers (implementation was October 2008). While BC Hydro did not conduct extensive research on residential tiered rate awareness in other jurisdictions, BC Hydro is aware that:

1. **In California, 58 per cent of surveyed Pacific Gas & Electric Company residential customers had heard about tiered rates, despite tiered rates having been the default rate since 1976;[2]**

2. **A 2007 survey by Rocky Mountain Power of residential customers in Utah found that 50 per cent of surveyed customers were "somewhat aware" or "very aware" that their summer residential rates are tiered (http://www.psc.state.ut.us/utilities/electric/09docs/0903536/051109dsmEXc.pdf , p. 5);**

3. **A 2013 survey by FortisBC of customers a year after switching to the two-tier Residential Conservation Rate found 29 per cent of customers were aware of a**

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[1] **Past RIB outreach efforts are catalogued in the Workshop 9a/9b consideration memo, Exhibit B-1, Appendix C-3B, page 22 of 50, response to Q.37**

[2] **D.15-07-001, CPUC Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-of-Use Rates, 7/3/15, p. 9 and p. 30, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF.**

change in rates and 19 per cent were either "somewhat" or "very" familiar with how the new two-tier rate works.[3]

[3] **See page 26 of http://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/Documents/131031_FBC%20Residential%20Conservation%20Rate%20Evaluation%20Report_FF.pdf.**

39.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2.4.1 Flat Rate, p. 5-22 Bill Impacts

BC Hydro states that its primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers.

1.39.1 Assuming that above scenario (i.e., adverse bill impact) took place but it was for a good policy objective such as conservation savings, should the bill impact be analyzed only for the purpose of designing mitigating factors? Should the rate structure design in itself primarily address economic efficiency and rate stability criteria?

RESPONSE:

No. BC Hydro has consistently examined bill impacts as part of assessing rate structure alternatives, and not only for the purpose designing mitigation measures (e.g., phase-in periods). The Commission has accepted this in prior decisions. An example is the 2011 RIB Re-Pricing Decision,[1] where the Commission determined that the central trade-off when assessing rates that are intended to deliver energy savings is between conservation and bill impacts.

[1] **Reasons for Decision accompanying Commission Order No. G-45-11, pages 14 and 15 of 19. Note that the Commission in the 2011 RIB Re-Pricing Decision included bill impacts as part of the Bonbright rate stability criterion.**

40.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, pp. 5-25 to 5-29
Three Step Rate

BC Hydro modelled and assessed three different options for a 3-step rate and only option A was carried forward in the Application. BC Hydro states that it does not anticipate much incremental conservation by adopting the 3-step A option and there would be moderate decreases in customer understanding and acceptance, as compared to the RIB rate.

1.40.1 In Slide 50 of Workshop 9a presentation materials (Exhibit C-3b), please explain the line labelled "Cumulative conservation vs. SQ." How does this compare to the "incremental conservation" identified in the preamble?

RESPONSE:

The Workshop 9a slide 50 (Exhibit B-1, Appendix C-3B page 50 of 609) "Cumulative Conservation vs. SQ" is calculated as the relative difference in cumulative rate structure conservation under the three-step rate option and the status quo RIB rate, given a rate design change in F2017. They are further explained as follows:

F2017: Rate Structure Conservation estimated between F2016 to F2017 under Three-Step Option A - Rate Structure Conservation estimated between F2016 to F2017 under SQ RIB = 34 GWh

F2018: Rate Structure Conservation estimated between F2016 to F2018 under Three-Step Option A - Rate Structure Conservation estimated between F2016 to F2018 under SQ RIB = 33 GWh

F2019: Rate Structure Conservation estimated between F2016 to F2019 under Three-Step Option A - Rate Structure Conservation estimated between F2016 to F2019 under SQ RIB = 33 GWh

"Incremental conservation" in the context of Exhibit B-1 page 5-29 is a generalized statement to say that BC Hydro is of the view that the projected 33 to 34 GWh increase in rate structure conservation over status quo is small, particularly given the major change in rate structure from two-step to three-step.

40.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, pp. 5-25 to 5-29
Three Step Rate

BC Hydro modelled and assessed three different options for a 3-step rate and only option A was carried forward in the Application. BC Hydro states that it does not anticipate much incremental conservation by adopting the 3-step A option and there would be moderate decreases in customer understanding and acceptance, as compared to the RIB rate.

1.40.2 Please confirm that the "cumulative conservation" identified on Slide 50 is calculated based on the price elasticity of -0.10 for Step 2 or the class average price elasticity of -0.05 for natural conservation.

RESPONSE:

Workshop 9a slide 50's "Cumulative Conservation" refers to total natural and rate structure conservation that is calculated based on an elasticity of -0.05 for Step 1, -0.10 for Step 2, and -0.10 for Step 3. Of these totals, -0.05 is assumed to be natural conservation.

For modelling and illustrative purposes, BC Hydro used the -0.10 elasticity for both Step 2 and Step 3. This is the midpoint of the range of elasticity estimated for all marginal consumption exposed to the higher price step above the RIB rate threshold of 675 kWh/month (1,350 kWh/billing period), inclusive of higher consuming customers, as shown in Exhibit B-1, Appendix C-3B on page 109 of 609. Note that there is a clerical error in 2013 RIB Evaluation Report Table E.4, and the correct Step 2 elasticity low estimate is -0.07, as evidenced by the text.

The 2013 RIB Evaluation Report Table 3.9 in Exhibit B-1, Appendix C-3B, page 132 of 609 indicates that customers with a higher level of consumption tend to have a higher responsiveness to price.

40.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, pp. 5-25 to 5-29
Three Step Rate

BC Hydro modelled and assessed three different options for a 3-step rate and only option A was carried forward in the Application. BC Hydro states that it does not anticipate much incremental conservation by adopting the 3-step A option and there would be moderate decreases in customer understanding and acceptance, as compared to the RIB rate.

1.40.3 Please confirm whether BC Hydro is using the same Step 2 price elasticity of -0.10 to calculate the potential conservation from step 3? Is empirical evidence available to support that consumption at the third Tier has higher elasticity than consumption in the lower tiers?

RESPONSE:

Confirmed. As discussed in BC Hydro's response to BCUC IR 1.40.2, there is empirical evidence that customers with a higher level of consumption tend to have a higher responsiveness to price. However, BC Hydro did not explicitly investigate elasticity with respect to the three-tier rate options presented as part of the 2015 RDA stakeholder engagement process.

40.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, pp. 5-25 to 5-29
Three Step Rate

BC Hydro modelled and assessed three different options for a 3-step rate and only option A was carried forward in the Application. BC Hydro states that it does not anticipate much incremental conservation by adopting the 3-step A option and there would be moderate decreases in customer understanding and acceptance, as compared to the RIB rate.

1.40.4 If only a very small percentage of customers consume at Step 3, does it matter that there is a "moderate decrease in customer understanding and acceptance?"

RESPONSE:

For the Three-Step Option A described on page 5-26 of Exhibit B-1, and using our modelling sample, it is expected that 57 per cent of residential customers would consume at the third step at least once. Further, 67 per cent of total marginal load would be exposed to the third step. Thus, a majority of Residential customers, not a "very small percentage", would consume at the third step.

The reason for this observation is because the third step is derived to maintain revenue neutrality after setting Step 1 at the status quo RIB rate and Step 2 at LRMC. The result is a narrow difference between the Step 1/2 and Step 2/3 thresholds. In this case there is no express trade-off as the Three-Step A alternative not only results in a "moderate decrease in customer understanding and acceptance", it also delivers little incremental conservation as compared to the existing RIB rate.

40.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, pp. 5-25 to 5-29
Three Step Rate

BC Hydro indicates that only one Canadian jurisdiction, YECL, has a 3-step rate structure.

1.40.5 Please discuss whether YECL would be a valid comparator at all to BC Hydro, given its geography, percentage of electric heat, size and customer types.

RESPONSE:

Generally speaking, BC Hydro considers that YECL is not directly comparable to BC Hydro due to, among other things, size.

BC Hydro surveyed YECL in response to BCOAPO's inquiry at Workshop 3 as to whether any Canadian n electric utility has adopted a three-step rate structure for its residential customers. During its jurisdictional review BC Hydro followed-up with YECL staff and learned that most YECL customers are unaware of the inclining block structure of the rates because the YECL billing system only shows customers one consumption amount and one cost of energy amount. Customers can only see the inclining block structure if they were to use the utility's online bill calculator. The staff that BC Hydro communicated with could not speak to the original drivers of the three step residential rate structure.

40.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, pp. 5-25 to 5-29
Three Step Rate

BC Hydro indicates that only one Canadian jurisdiction, YECL, has a 3-step rate structure.

1.40.6 BC Hydro also indicates that the CPUC had recently reduced the current four step residential rate structure of three large California utilities to 2 steps. To the best of BC Hydro's knowledge, please generally discuss if the 3-step rate achieved the expected conservation savings and the reasons for reducing the multi-Tier rate to a 2-Tier rate. ?

RESPONSE:

Because BC Hydro has not implemented a three-step rate, there is no way to compare achieved and expected savings for BC Hydro Residential customers under a three-step rate. BC Hydro interprets the question as intending to ask about the conservation savings of California's multi-tiered rates (the rates with more than two tiers).

While two-tier rates were adopted for California utilities in 1976, the multi-step rates in California were established in response to the energy crisis of 2001. California Assembly Bill 1X (AB1X) mandated that all residential usage up to 130 per cent of baseline be capped at rate levels in effect on February 1, 2001. Consequently, the CPUC replaced the then-existing two-tiered structure with a five-tiered structure so that revenue requirement increases could be collected in tiers three through five, while holding tiers one and two at the AB 1X mandated frozen levels.[1]

It is BC Hydro's understanding that the California multi-tier structure was enacted quickly in response to the financial crisis imposed on utilities by the energy crisis, and BC Hydro is unaware of any forecasts of expected conservation impact for those multi-tier rates, nor is BC Hydro aware of estimates of actual conservation impact for those rates. BC Hydro is aware of conservation impact studies conducted as part of California's Residential Rate Reform proceeding. Analyses cited in the CPUC Decision for the proceeding present conservation impacts of transitioning from the current multi-tiered structures to alternate rate forms under various theories of how customers respond to tiered pricing. Those results can be

[1] **D.15-07-001, *supra*, BC Hydro response to BCUC IR 1.38.2, pp. 12-13.**

found on pages 30 through 40 of Decision D.15-07-001.[2] There is, however, no discussion of actual versus expected achievements for the proposed rate designs.

Decision D.15-07-001 states: "This reform is intended to make rates more understandable to customers and more cost-based". In particular, the Decision cites concern about bill volatility and high bills for a subset of customers as a key issue.

[2] **Ibid.**

41.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, p. 5-33 to p.5-35
RIB pricing principles

BC Hydro explains that by applying the RRA increases equally to all 3 rate elements, the step 2 energy rate would exceed the upper range of BC Hydro's LRMC (option 1).

Option 2 is to apply the RRA increase to the Step 1 energy rate and basic charge while holding step 2 energy rate at its current level.

1.41.1 In the Commission's 2011 RIB Rate Re-pricing decision (page 8 of 19), it was affirmed that the levelized weighted average plant-gate price of BC Hydro's most recent call for energy as a proxy for LRMC. It does not include BC Hydro's capacity costs. Would including capacity costs in the LRMC estimate arguably lend the 2-step rate to be an economically efficient rate?

RESPONSE:

Confirmed that the energy LRMC used for the 2011 RIB rate re-pricing application and decision (based on the levelized weighted average plant gate price of the 2009 Clean Power Call; refer to Exhibit B-1, page 2-41, lines 2-5) did not include a generation capacity value.

As illustrated in Figure 5-18, page 5-34 of Exhibit B-1, the Option 1 RIB Step 2 rate remains at or slightly above the upper end of the energy LRMC range for F2017 to F2019 with the inclusion of a generation capacity value in the energy LRMC. As set out in Table 2-7 and page 2-40 of Exhibit B-1, BC Hydro uses the energy LRMC as a reference for purposes of applying the Bonbright economic efficiency criterion.

The inclusion of generation capacity value in the energy LRMC used as a reference for the RIB Step 2 rate would not necessarily result in a more economically efficient price than the use of the energy-only LRMC. The problem is that the generation capacity marginal cost is a peak-demand-based cost, not an energy cost. Signaling the cost of capacity via a non-time-differentiated energy rate would distort the capacity price signal. The uniform energy price signal would be too low at the time of peak demand, and too high at all other times. Therefore it is not clear whether the inclusion of the generation capacity cost for purposes of the RIB Step 2 rate would be more or less economically efficient than a rate based on the energy-only LRMC.

Please also refer to BC Hydro's response to BCUC IR 1.13.1.

41.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2 Residential Default Rate, p. 5-33 to p.5-35
RIB pricing principles

BC Hydro explains that by applying the RRA increases equally to all 3 rate elements, the step 2 energy rate would exceed the upper range of BC Hydro's LRMC (option 1).

Option 2 is to apply the RRA increase to the Step 1 energy rate and basic charge while holding step 2 energy rate at its current level.

1.41.2 For Figure 5-19 please discuss whether economic efficiency may still be achieved given that the Step 2 rate will be higher than LRMC for option 2 (with more differential in F17 and less so by F19).

RESPONSE:

Table 2-7 of Exhibit B-1 describes the Bonbright economic efficiency as criteria: "Price signals that encourage efficient use and discourage inefficient use." BC Hydro believes that efficient usage for its Residential customers is best encouraged by Step 2 prices that reflect LRMC. This does not require that prices be exactly equal to LRMC. While the 11.95 cent/kWh RIB rate step 2 price (F2016) is somewhat above the energy LRMC range, BC Hydro believes that it is reasonably close enough to LRMC to continue to encourage efficient use. Similarly, BC Hydro believes that the rates under RIB rate F2017 to F2019 pricing principle Option 1 would also continue to encourage efficient use, though to a lesser extent than F2017 to F2019 pricing principle Option 2.

42.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2.5.2 Basic Charge; Section 5.2.5.3 Minimum Charge, pp. 5-41 to 5-43 Basic Charge and Minimum Charge

BC Hydro states that the Basic Charge is intended to recover a portion of its customer costs, while minimum charges are intended to recover a minimum contribution towards fixed costs, or some portion of the cost of customers remaining connected to the system during periods of very low consumption or dormancy.

Currently the Basic Charge is the Minimum Charge. It is stated in the Application that $15 a month Minimum Charge is roughly equivalent to the average fixed Distribution and customer-related cost per month per Residential customer. However, BC Hydro is not proposing a minimum charge.

1.42.1 Please clarify whether BC Hydro, when modelling the $15 per month minimum charge, also considered generation and transmission costs in addition to customer cost and distribution costs?

RESPONSE:

As part of section 3.2 of the Workshop 11a/11b consideration memo, BC Hydro clarified that the RIB rate basic charge (which is the minimum charge) should only refer to customer-related cost recovery (refer to page 171 of 382 of Appendix C-4B of Exhibit B-1.

Accordingly, the minimum charge as modelled does not include any Transmission or Generation costs because none of these costs are Customer-related costs and instead are classified as energy or demand in the COS analysis.

42.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2.5.2 Basic Charge; Section 5.2.5.3 Minimum Charge, pp. 5-41 to 5-43 Basic Charge and Minimum Charge

BC Hydro states that the Basic Charge is intended to recover a portion of its customer costs, while minimum charges are intended to recover a minimum contribution towards fixed costs, or some portion of the cost of customers remaining connected to the system during periods of very low consumption or dormancy.

Currently the Basic Charge is the Minimum Charge. It is stated in the Application that $15 a month Minimum Charge is roughly equivalent to the average fixed Distribution and customer-related cost per month per Residential customer. However, BC Hydro is not proposing a minimum charge.

1.42.2 What percentage of customer-related costs is recovered through the current basic charge?

RESPONSE:

As discussed at Workshop 9-B, about 45 per cent of Residential customer-related costs are recovered through the basic charge. The calculation is approximately equal to forecast F2016 Residential basic charge revenue of $119.3 million *divided by* total F2016 customer-related costs assigned to the Residential class of $273.4 million, as reported on sheet 4.1 of the F2016 COS excel file attached in Appendix E of Exhibit B- 1.

For clarity, the basic charge recovers only customer-related costs. The remainder of Residential customer-related costs are recovered through the energy charges. Please also refer to BC Hydro's response to BCUC IR 1.53.2.

42.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2.5.2 Basic Charge; Section 5.2.5.3 Minimum Charge, pp. 5-41 to 5-43 Basic Charge and Minimum Charge

BC Hydro states that the Basic Charge is intended to recover a portion of its customer costs, while minimum charges are intended to recover a minimum contribution towards fixed costs, or some portion of the cost of customers remaining connected to the system during periods of very low consumption or dormancy.

Currently the Basic Charge is the Minimum Charge. It is stated in the Application that $15 a month Minimum Charge is roughly equivalent to the average fixed Distribution and customer-related cost per month per Residential customer. However, BC Hydro is not proposing a minimum charge.

1.42.3 On page 5-42, BC Hydro discusses its jurisdictional assessment of Canadian utilities' residential Basic Charge cost recovery. Does BC Hydro also have a jurisdictional assessment of minimum charges?

RESPONSE:

Yes, BC Hydro surveyed whether Canadian utilities have minimum charges for residential service.

As reported in Attachment 3 to the RDA Workshop 9a/9b Discussion Guide, at Appendix C3-B of Exhibit B-1 (page 287), for all utilities surveyed the basic charge is the minimum charge, as it is for BC Hydro. Thus in materials subsequent to this assessment, and in particular in slide 28 of the Workshop 9a presentation as footnoted on page 5-42 of Exhibit B-1, BC Hydro simplified the labeling of its survey results to report only "Basic Charge" information.

42.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2.5.2 Basic Charge; Section 5.2.5.3 Minimum Charge, pp. 5-41 to 5-43 Basic Charge and Minimum Charge

BC Hydro states that the Basic Charge is intended to recover a portion of its customer costs, while minimum charges are intended to recover a minimum contribution towards fixed costs, or some portion of the cost of customers remaining connected to the system during periods of very low consumption or dormancy.

Currently the Basic Charge is the Minimum Charge. It is stated in the Application that $15 a month Minimum Charge is roughly equivalent to the average fixed Distribution and customer-related cost per month per Residential customer. However, BC Hydro is not proposing a minimum charge.

1.42.4 Please provide the F2014 and F2015 data, in tabular format, of Residential customers who paid the Minimum Charge for a) 12 months of the year, b) 9 months of the year, c) 6 months of the year, and d) 3 months of the year.

RESPONSE:

The number of Residential customer accounts who paid only the basic charge (minimum charge for status quo RIB) for 3,6,9, and 12 months are estimated below.

Months	F2014	F2015
3	1,105	1,108
6	2,172	2,178
9	246	255
12	3,003	3,015

42.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.2.5.2 Basic Charge; Section 5.2.5.3 Minimum Charge, pp. 5-41 to 5-43 Basic Charge and Minimum Charge

BC Hydro states that the Basic Charge is intended to recover a portion of its customer costs, while minimum charges are intended to recover a minimum contribution towards fixed costs, or some portion of the cost of customers remaining connected to the system during periods of very low consumption or dormancy.

Currently the Basic Charge is the Minimum Charge. It is stated in the Application that $15 a month Minimum Charge is roughly equivalent to the average fixed Distribution and customer-related cost per month per Residential customer. However, BC Hydro is not proposing a minimum charge.

1.42.4.1 Please provide the regional breakdown to the F2014 and F2015 data.

RESPONSE:

The number of Residential customers who paid only the basic charge (minimum charge for status quo RIB) for 3, 6, 9, and 12 months, by region, are estimated below.

F2014, Months	Lower Mainland	Northern	Southern Interior	Vancouver Island
3	256	261	283	305
6	270	625	952	325
9	78	61	55	52
12	653	845	906	599
F2015, Months				
3	168	245	253	172
6	230	626	909	328
9	64	64	64	66
12	663	850	909	683

43.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.3 Residential Dual Fuel E-Plus Rate, pp. 5-54 to 5-56
E-Plus customers interruption notice

BC Hydro favours amending RS 1105 Special Condition 1 to provide a practical interruptible option. As its business practice, one of the ways of notifying E-plus customers for interruption is "up to one week's notice that an interruption event is likely to occur."

1.43.1 Please provide an example of an *event* that will allow BC Hydro to provide up to one week's notice to E-Plus customers regarding interruption.

RESPONSE:

Response to be provided on January 12, 2016.

43.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.3 Residential Dual Fuel E-Plus Rate, pp. 5-54 to 5-56
E-Plus customers interruption notice

BC Hydro favours amending RS 1105 Special Condition 1 to provide a practical interruptible option. As its business practice, one of the ways of notifying E-plus customers for interruption is "up to one week's notice that an interruption event is likely to occur."

1.43.2 Please describe the investigation work – planning, execution and outcome – undertaken on residential demand response described on page 5-54.

RESPONSE:

BC Hydro notes that the reference to the residential DSM capacity-focused (demand response) pilot in the discussion of BC Hydro's residential E-Plus rate proposal at page 5-54 is for context only. The pilot is a program as referenced in the definition of 'demand-side measure' in section 1 of the *CEA*, and therefore expenditures associated with the pilot will be the subject of the DSM expenditure schedule determination request submitted to the Commission as part of or contemporaneously with the F2017 RRA pursuant to subsection 44.2(1)(a) of the *UCA*. The residential demand response pilot is not a "rate" as defined in section 1 of the *UCA*.

Nevertheless, to be helpful, BC Hydro provides the following information concerning the Residential demand response pilot project.

BC Hydro is currently conducting a demonstration pilot in Sidney and North Saanich using wireless load control relays on residential water heaters in participating residential customers' homes. The pilot also includes field testing of an alternative three-element water heater which may also help create demand reductions. In-field testing began in 2015 and will carry into 2016. After the conclusion of the testing period, a participant survey will be conducted and meter data will be analyzed to determine the impact of these two measures on both demand and customers.

BC Hydro is also in the early stages of researching additional DSM program demand response options including programmable communicating thermostats and other connected home technologies. Thermostat solutions need to be suitable for homes with baseboard heating and provide cost-effective management of multiple heating zones.

44.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.4 Low Income rate, p. 5-57 and p. 5-58
Low income rate

BC Hydro states that low income rates are likely to be seen as unduly preferential or unduly discriminatory and divorced from the cost causation principle (p. 5-58). BC Hydro also states that in those jurisdictions where low income rates have been introduced, legislation has been introduced.

1.44.1 If low income rates were introduced and approved, please discuss how BC Hydro would verify income data without violation of personal information. Please also discuss any administrative barriers in this regard.

RESPONSE:

Please refer to section 5.1 of Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

45.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1 Application, Section 5.2.5.1, Table 5-8, pp. 5-34 to 5-37 F2017–F2019 Pricing principles and bill impacts

On page 5-34, BC Hydro provides a table showing the bill impacts under Pricing Principles Option 1. For Option 2, BC Hydro provides a figure for each of the three fiscal years (Figures 5-20 to 5-22) showing the cumulative bill impacts versus annual consumption.

1.45.1 Please provide similar figures for Option 1.

RESPONSE:

Bill Impacts for all customers is at the RRA rate increase (page 5-34; section 5.2.5.1) per Exhibit B-1, Table 5-8. This yields the following cumulative impacts:

F2017(%) = 4 per cent

F2018(%) = 7.64 per cent
= (1 + F2017 RRA) * (1 + F2018 RRA) – 1 = (1 + 4 per cent)(1 + 3.5 per cent) - 1

F2019(%) = 10.9 per cent
= (1 + F2017 RRA)*(1 + F2018 RRA) * (1 + F2019 RRA) –
1 = (1 + 4 per cent)(1 + 3.5 per cent)(1 + 3 per cent) - 1

The requested graphs are reproduced for Option 1:

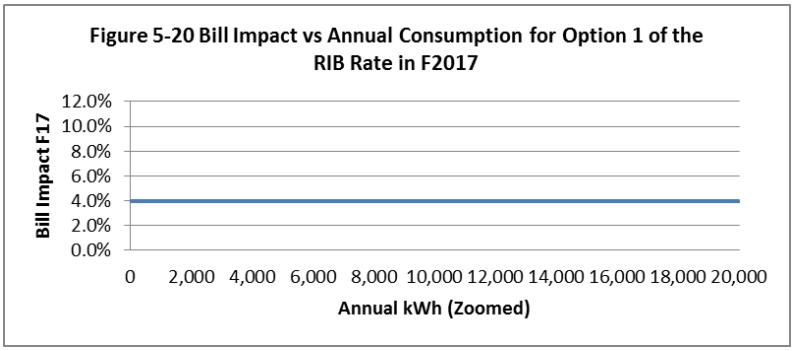


Figure 5-21 Cumulative Bill Impact vs Annual Consumption for Option 1 of the RIB Rate in F2018

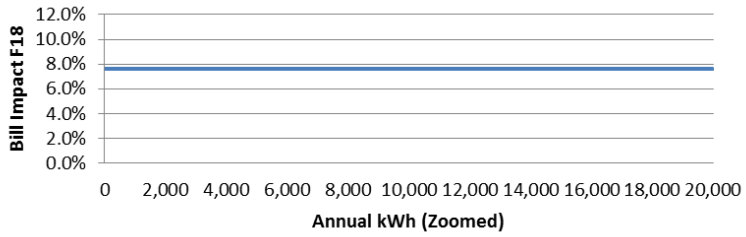
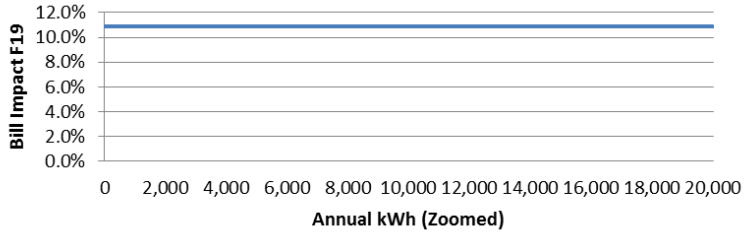


Figure 5-22 Cumulative Bill Impact vs Annual Consumption for Option 1 of the RIB Rate in F2019



46.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.1 Definition of Low Income Customers, p. 5-63
RIB Rate Report Proceeding – Definition of low income customers

In the Commission's RIB Rate Report proceeding, BCOAPO's submission dated October 16, 2015, states on pages 4 to 5: "…given the high incidence (over 25%) of non-responses, it would be useful if BC Hydro were to examine the basic parameters (e.g. electricity usage, heating type) of the two groups (respondents vs. non-respondents) in order to assess whether the inclusion of these records skews the general characteristics of 'low income' customers."

In the Commission's RIB Rate Report Proceeding, COPE's submission dated October 16, 2015, COPE states on page 5: "Energy or fuel poverty is already a growing issue in Canada and BC but given the ever steepening curve of energy cost increases in the future, its relevance and importance is bound to grow."

1.46.1 As part of its RIB Rate Report proceeding, please confirm if BC Hydro would assess whether the estimate of the characteristics of the low income population is skewed as per BCOAPO's suggestion? Why or why not?

RESPONSE:

BC Hydro has determined that the inclusion of 'non-respondents' (households that did not report household income in response to the REUS) in its low income analysis does not skew the general characteristics of the customer households flagged as being low income qualified in the REUS data.

46.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.1 Definition of Low Income Customers, p. 5-63
RIB Rate Report Proceeding – Definition of low income customers

In the Commission's RIB Rate Report proceeding, BCOAPO's submission dated October 16, 2015, states on pages 4 to 5: "…given the high incidence (over 25%) of non-responses, it would be useful if BC Hydro were to examine the basic parameters (e.g. electricity usage, heating type) of the two groups (respondents vs. non-respondents) in order to assess whether the inclusion of these records skews the general characteristics of 'low income' customers."

In the Commission's RIB Rate Report Proceeding, COPE's submission dated October 16, 2015, COPE states on page 5: "Energy or fuel poverty is already a growing issue in Canada and BC but given the ever steepening curve of energy cost increases in the future, its relevance and importance is bound to grow."

1.46.2 Does BC Hydro agree with COPE's assertion in the preamble? Please comment on the relevance of examining energy or fuel poverty in the RIB Rate Proceeding report and the feasibility of doing so.

RESPONSE:

BC Hydro understands from BCOAPO that it intends to submit socio-economic evidence as part of its intervener evidence low income rate proposal. As set out at Exhibit B-1, page 5-2, lines 22 to 24, BC Hydro's consideration of a low income rate will occur through IRs on such evidence, additional legal submissions and other processes as the regulatory review of RDA Module 1 unfolds.

Defining energy or fuel poverty is not a simple task. One can ask several different questions concerning the definition of energy poverty. Is energy poverty the same as income poverty? Is energy poverty based on access to energy services such as cooking, communications or lighting? Or is it based on quantities of energy that people use? These questions have generated several different approaches to measuring energy poverty such as:

- **Minimum amount of physical energy necessary for basic needs such as cooking and lighting;**
- **Type and amount of energy that is used for those at the poverty line;**

- **Households that spend more than a certain percent of their expenditure on energy; and**

- **The income point below which energy use and or expenditures remains the same, implying this is the bare minimum energy needs.**

BC Hydro submits that the Minister RIB Report Letter does not require either the Commission or the two utilities to examine energy or fuel poverty for purposes of responding to the five questions. Among other things, the Commission RIB Report Methodology Letter asked how the two utilities intend to define 'low income customers'. Both BC Hydro and FortisBC propose using Statistics Canada's LICO as the method for defining low income customers, and no intervener participating in the RIB Report process opposes this proposal.

46.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.1 Definition of Low Income Customers, p. 5-63
RIB Rate Report Proceeding – Definition of low income customers

In the Commission's RIB Rate Report proceeding, BCOAPO's submission dated October 16, 2015, states on pages 4 to 5: "…given the high incidence (over 25%) of non-responses, it would be useful if BC Hydro were to examine the basic parameters (e.g. electricity usage, heating type) of the two groups (respondents vs. non-respondents) in order to assess whether the inclusion of these records skews the general characteristics of 'low income' customers."

In the Commission's RIB Rate Report Proceeding, COPE's submission dated October 16, 2015, COPE states on page 5: "Energy or fuel poverty is already a growing issue in Canada and BC but given the ever steepening curve of energy cost increases in the future, its relevance and importance is bound to grow."

1.46.3 Please comment on the usefulness and feasibility of using data from the Ministry of Social Development and Social Innovation, such as crisis grant provision data, or other data, to respond to the three questions from the Minister, which relate to low income customers.

RESPONSE:

BC Hydro assumes that the Minister RIB Report Letter questions are Question 2 and Question 3. Overall while BC Hydro is of the view the MSDSI data would be useful, BC Hydro does not believe it is feasible to use MSDSI data to respond to these two questions. The Minister RIB Report Letter provides that the Commission report is to issue after the close of the RDA evidentiary phase and it is not possible to use the MSDSI data within that timeframe.

MSDSI provides assistance to approximately 130,000 of the 170,000 BC Hydro customers estimated to have family incomes below the LICO threshold. While MSDSI's client list would not provide insight into the full low income population, it would be a more representative sample than the data BC Hydro currently has available from the REUS.

MSDSI does not record BC Hydro or FortisBC account numbers (except for those customers receiving direct payments) so there wouldn't be a perfect match between data sets. However, it is likely that a sufficient number of names and addresses could be matched to make analysis of the characteristics of BC Hydro's and FortisBC's low income customers possible.

With respect to feasibility, BC Hydro and MSDSI are both subject to the *FOIPPA*, while FortisBC is subject to the *Personal Information Protection Act*. However, the suggestion is feasible provided that the three organizations (MSDSI, BC Hydro, FortisBC) agree to share customer/client records and that the data is handled in accordance with *FOIPPA*, including keeping information private and within Canada.

It would be necessary to complete a Privacy Impact Assessment before a definitive answer can be provided. However, the following approach would be taken:

- **It would first be necessary to determine if the customer consent in MSDSI's application would authorize disclosure for this purpose;**
- **If existing consent by MSDSI clients is not sufficient, it is still possible to justify the sharing of information on the basis of the intent being to benefit those individuals whose personal information is being disclosed;**
- **Protocols would be established under an Information Sharing Agreement between the organizations. Operationally, this would include requirements for encryption, anonymizing data, secured storage and authorized access;**
- **The need for use of an independent party to compile or analyze the data would be assessed (to avoid BC Hydro and FortisBC from seeing the personal information of the other's customers before it is anonymized); and**
- **The Office of the Information and Privacy Commissioner would be consulted to obtain its feedback for the adequacy of procedures and adherence to *FOIPPA*.**

47.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.2 Defining Factors Leading to High Energy Use, p. 5-69
RIB Rate Report Proceeding – High energy use

BC Hydro defines "high energy use" to include both energy consumption and peak demand. BC Hydro identifies a) electricity consumption by heating fuel: and b) electricity consumption by housing type within region as the factors driving higher than average annual electricity consumption. BC Hydro rejected number of occupants as a factor because it is correlated with the floor area of the home.

In the Commission's RIB Rate Report proceeding, BCOAPO's Submission dated October 16, 2015, states on page 6 that:

There would appear to be merit in both BC Hydro and FortisBC exploring domestic water heating fuel and the presence of other electric high use end-uses, assuming the data exists in their respective REUS's to do so... given that the Minister's questions focus on customers without access to natural gas and low income customers, both Companies should seek to refine their analysis to specifically look at which factors lead to high energy use for each of these two groups as opposed to the Residential class in general.

1.47.1 Please confirm if "high energy use" is synonymous with "high electric use" in BC Hydro's definition. In BC Hydro's view, should there be a difference in definition for the purpose of the RIB Rate Report?

RESPONSE:

Confirmed. BC Hydro's definition of "high energy use" is related solely to electricity consumption. BC Hydro does not believe there should be a difference in definition for the purpose of the RIB Rate Report. The Minister is seeking information on how stepped residential electricity rates impact low income customers and customers without access to natural gas. As such, BC Hydro does see the value in expanding the definition beyond electricity use.

47.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.2 Defining Factors Leading to High Energy Use, p. 5-69
RIB Rate Report Proceeding – High energy use

BC Hydro defines "high energy use" to include both energy consumption and peak demand. BC Hydro identifies a) electricity consumption by heating fuel: and b) electricity consumption by housing type within region as the factors driving higher than average annual electricity consumption. BC Hydro rejected number of occupants as a factor because it is correlated with the floor area of the home.

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1.47.1 Please confirm if "high energy use" is synonymous with "high electric use" in BC Hydro's definition. In BC Hydro's view, should there be a difference in definition for the purpose of the RIB Rate Report?

1.47.1.1 If the response to the above question is affirmative, please comment on the feasibility of BC Hydro reporting on high energy (or electricity) use for residential customers without access to natural gas and those with access.

RESPONSE:

It is feasible for BC Hydro to report on high electricity use for Residential customers without natural gas using BC Hydro's proposed definition of "access to natural gas" as described in section 5.5.3 of Exhibit B-1. BC Hydro does not believe it is feasible to report on combined electric and natural gas usage as BC Hydro does not have access to the natural gas usage by its customers nor does FortisBC have access to BC Hydro's customers' electricity consumption. There would be confidentiality issues with sharing the information amongst the utilities.

47.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.2 Defining Factors Leading to High Energy Use, p. 5-69
RIB Rate Report Proceeding – High energy use

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There would appear to be merit in both BC Hydro and FortisBC exploring domestic water heating fuel and the presence of other electric high use end-uses, assuming the data exists in their respective REUS's to do so... given that the Minister's questions focus on customers without access to natural gas and low income customers, both Companies should seek to refine their analysis to specifically look at which factors lead to high energy use for each of these two groups as opposed to the Residential class in general.

1.47.2 Please comment on the feasibility and usefulness of responding to the Minister's Question 3 for total household energy-use (i.e. all fuel sources).

RESPONSE:

Please refer to BC Hydro's responses to BCUC IRs 1.47.1 and 1.47.1.1.

47.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.2 Defining Factors Leading to High Energy Use, p. 5-69
RIB Rate Report Proceeding – High energy use

BC Hydro defines "high energy use" to include both energy consumption and peak demand. BC Hydro identifies a) electricity consumption by heating fuel: and b) electricity consumption by housing type within region as the factors driving higher than average annual electricity consumption. BC Hydro rejected number of occupants as a factor because it is correlated with the floor area of the home.

In the Commission's RIB Rate Report proceeding, BCOAPO's Submission dated October 16, 2015, states on page 6 that:

There would appear to be merit in both BC Hydro and FortisBC exploring domestic water heating fuel and the presence of other electric high use end-uses, assuming the data exists in their respective REUS's to do so... given that the Minister's questions focus on customers without access to natural gas and low income customers, both Companies should seek to refine their analysis to specifically look at which factors lead to high energy use for each of these two groups as opposed to the Residential class in general.

1.47.2.1 What data, listed below, does BC Hydro have to examine total household energy use?

a) Data on number and amount of consumption of non-electric end-uses from the Residential End-Use Survey (REUS)?
b) Estimates of the cross-elasticity of demand between electricity and natural gas prices?
c) Other?

RESPONSE:

a) Yes, BC Hydro has data on main and secondary non-electric space heating systems, non-electric water heating systems, natural gas cooking appliances, natural gas/propane dryers, gas heated indoor/outdoor pools and hot tubs. However, BC Hydro does not have consumption information for these end-uses.

b) and c) Please refer to BC Hydro's response to BCUC IR 1.47.2.3.

47.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.2 Defining Factors Leading to High Energy Use, p. 5-69
RIB Rate Report Proceeding – High energy use

BC Hydro defines "high energy use" to include both energy consumption and peak demand. BC Hydro identifies a) electricity consumption by heating fuel: and b) electricity consumption by housing type within region as the factors driving higher than average annual electricity consumption. BC Hydro rejected number of occupants as a factor because it is correlated with the floor area of the home.

In the Commission's RIB Rate Report proceeding, BCOAPO's Submission dated October 16, 2015, states on page 6 that:

There would appear to be merit in both BC Hydro and FortisBC exploring domestic water heating fuel and the presence of other electric high use end-uses, assuming the data exists in their respective REUS's to do so... given that the Minister's questions focus on customers without access to natural gas and low income customers, both Companies should seek to refine their analysis to specifically look at which factors lead to high energy use for each of these two groups as opposed to the Residential class in general.

1.47.2.2 Please comment on the feasibility and usefulness of modelling total energy use from all sources by converting energy use into a common measure (e.g., GJ or kWh) and comparing the cost of total energy consumption between those with and those without access to natural gas. Furthermore, given that natural gas prices are at historically low levels, please provide comment on the usefulness of modelling three comparisons; one with natural gas rates in 2008, another using 2012 rates and another using current 2015 rates. If not useful, please provide any other alternative approaches.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.47.1.1.

47.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.2 Defining Factors Leading to High Energy Use, p. 5-69
RIB Rate Report Proceeding – High energy use

BC Hydro defines "high energy use" to include both energy consumption and peak demand. BC Hydro identifies a) electricity consumption by heating fuel: and b) electricity consumption by housing type within region as the factors driving higher than average annual electricity consumption. BC Hydro rejected number of occupants as a factor because it is correlated with the floor area of the home.

In the Commission's RIB Rate Report proceeding, BCOAPO's Submission dated October 16, 2015, states on page 6 that:

There would appear to be merit in both BC Hydro and FortisBC exploring domestic water heating fuel and the presence of other electric high use end-uses, assuming the data exists in their respective REUS's to do so... given that the Minister's questions focus on customers without access to natural gas and low income customers, both Companies should seek to refine their analysis to specifically look at which factors lead to high energy use for each of these two groups as opposed to the Residential class in general.

1.47.2.3 Please comment on the feasibility and usefulness of the Commission requesting BC Hydro's comments in the report on the Minister's questions about the impact of natural gas prices on electricity consumption for those with access to natural gas.

RESPONSE:

BC Hydro questions the usefulness of requesting comments regarding the impact of natural gas prices on electricity consumption for those customers with access to natural gas. The Minister RIB Report Letter questions relate to impacts of the RIB rate to customers without access to natural gas rather than those who have access to natural gas.

While it would be feasible to model the impacts of natural gas prices on electricity consumption for those customers with access to natural gas, it would require a significant amount of time and labour to develop an econometric model whereby the demand for electricity is a function of a number of factors including the historic price of natural gas.

47.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.2 Defining Factors Leading to High Energy Use, p. 5-69
RIB Rate Report Proceeding – High energy use

BC Hydro defines "high energy use" to include both energy consumption and peak demand. BC Hydro identifies a) electricity consumption by heating fuel: and b) electricity consumption by housing type within region as the factors driving higher than average annual electricity consumption. BC Hydro rejected number of occupants as a factor because it is correlated with the floor area of the home.

In the Commission's RIB Rate Report proceeding, BCOAPO's Submission dated October 16, 2015, states on page 6 that:

There would appear to be merit in both BC Hydro and FortisBC exploring domestic water heating fuel and the presence of other electric high use end-uses, assuming the data exists in their respective REUS's to do so... given that the Minister's questions focus on customers without access to natural gas and low income customers, both Companies should seek to refine their analysis to specifically look at which factors lead to high energy use for each of these two groups as opposed to the Residential class in general.

1.47.3 Please specify if there are additional regions other than Vancouver Island, the North, South Interior and Lower Mainland in the analysis of "housing type within region." Please explain whether or not the regions should be broken down further.

RESPONSE:

As it pertains to REUS analysis, BC Hydro has the ability to decompose the four broad regions into smaller sub-regions based on service town – assuming there are a sufficient number of sample records – or groups of service towns.

For the purpose of RIB rate-related analytics, BC Hydro believes that the four broad regions should not be broken down further as they sufficiently account for the regional differences in customer demographics, housing characteristics and climate zones across its service area. Sub-regional analysis will produce sample statistics that are less reliable when generalizing the findings to the populations in question.

47.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.2 Defining Factors Leading to High Energy Use, p. 5-69
RIB Rate Report Proceeding – High energy use

BC Hydro defines "high energy use" to include both energy consumption and peak demand. BC Hydro identifies a) electricity consumption by heating fuel: and b) electricity consumption by housing type within region as the factors driving higher than average annual electricity consumption. BC Hydro rejected number of occupants as a factor because it is correlated with the floor area of the home.

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1.47.4 Please comment on the feasibility of BC Hydro reporting on other "factors" that lead to high energy use such as various end-uses including but limited to water heating fuel, pools, hot tubs, etc.

RESPONSE:

It is feasible to conduct analysis and report on other end-uses that could lead to high energy use, but this analysis would be time and labour intensive and only for those end-uses that are adequately represented in the REUS sample data.

47.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.2 Defining Factors Leading to High Energy Use, p. 5-69
RIB Rate Report Proceeding – High energy use

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1.47.4.1 What specific end-use data does BC Hydro have from its 2012 REUS?

RESPONSE:

BC Hydro has completed the 2014 REUS which provides more current data than the 2012 REUS. For each of the following end-uses, the 2014 REUS provides data on the number and type of equipment in the household under each of the following categories, and for some items, the age of the equipment and hours of use:

- **Space heating systems**
- **Water heating systems**
- **Home cooling and air cleaning systems**
- **Refrigerators and freezers**
- **Cooking appliances**
- **Laundry and dishwashing appliances**
- **Water-use items**
- **Televisions and peripherals**
- **Computers & Peripherals**
- **Plug load power management items**
- **Pools and hot tubs**
- **Light bulbs and lighting controls**
- **Other electrical end-uses.**

47.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.2 Defining Factors Leading to High Energy Use, p. 5-69
RIB Rate Report Proceeding – High energy use

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1.47.4.2 Is BC Hydro amenable to reporting on household occupancy even though it may be correlated to home floor area? If not, why not? If not, please provide evidence of the correlation between household occupancy and home floor area.

RESPONSE:

Yes, BC Hydro can provide REUS/RIB analytics based on the number of household occupants.

48.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, p. 5-70
RIB Rate Report Proceeding – definition of access to natural gas

BC Hydro proposes adopting a community approach to define access to natural gas.

In the Commission's RIB Rate Report proceeding, BCOAPO's Submission dated October 16, 2015, states on page 12 that: "In our view, an equally valid definition of "access to natural gas" could include residential customers who cannot afford to switch from electricity to natural gas or are unable to switch for other reasons, even if they could connect to natural gas service in their homes."

In the Commission's RIB Rate Report proceeding, BCSEA's Submission dated October 16, 2015, states on page 4 that:

BCSEA-SCBC recommend that the Commission elaborate the definition of 'with and without access to natural gas' to deal with customers in communities such Revelstoke (which has access to piped propane), and customers who are outside of both the communities listed by FEI as having natural gas service and the communities listed by BC Hydro (and FBC in due course) as not having natural gas service.

1.48.1 Please comment on the feasibility of adopting the definition of access to natural gas as proposed by BCOAPO. Can this aspect of the access be reported on in any way?

RESPONSE:

BC Hydro does not believe it is feasible to adopt the definition of access to natural gas as proposed by BCOAPO. First, it is not clear how the term "afford" would be defined. Second, it is unlikely that BC Hydro would have the information required to evaluate whether or not a household can afford to switch from electricity to natural gas or whether there are other reasons that would prevent a switch to natural gas.

48.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, p. 5-70 RIB Rate Report Proceeding – definition of access to natural gas

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1.48.2 Please comment on the feasibility of adopting the definition of access to natural gas as proposed by BCSEA.

RESPONSE:

In BC Hydro's view it is not feasible to include customers outside the communities listed below (which may be refined) as not having natural gas service:

- **As described in section 5.5.3 of Exhibit B-1, BC Hydro supports containing the definition of "without access to natural gas" to a community level as in BC Hydro's view this is the only practical approach. Expanding beyond this would require much more granular information than BC Hydro has available to it; and**

- **The RIB Report-related analysis concerning customers without access to natural gas must focus on customers without natural gas availability as opposed to customers that could have natural gas service in the area in which they live but choose not to connect to the B.C. natural gas distribution system. Accordingly, BC Hydro proposed not to include Revelstoke with those communities which do not have access to natural gas because customers in Revelstoke have the option of piped propane to their homes for space heating similar to having natural gas service.**

BC Hydro provides the following list of 107 communities in its service area that do not have access to natural gas. BC Hydro cross-referenced these communities with its billing system and concludes that it is largely representative. BC Hydro will work with FortisBC to confirm a final list of communities for the purpose of the RIB Rate Report proceeding.

ALERT BAY	EAGLE BAY	LAKE ERROCK	SANDSPIT
ALEXIS CREEK	EDGEWATER	LEE CREEK	SCOTCH CREEK
ANAHIM LAKE	EDGEWOOD	LILLOOET	SETON PORTAGE
ANGLEMONT	FAIRMONT HOT SPRINGS	LIONS BAY	SICAMOUS
ARRAS	FANNY BAY	LUND	SOINTULA
BAMFIELD	FAUQUIER	MAGNA BAY	SOUTH HAZELTON
BARRIERE	FIELD	MALAKWA	SOUTH WELLINGTON
BELLA COOLA	FURRY CREEK	MANSON LANDING	SOUTHBANK
BIG LAKE	GARDEN BAY	MARA	SUNSHINE VALLEY
BIRKEN	GILLIES BAY	MCLEESE LAKE	SWANSEA POINT
BOSTON BAR	GITWINKSIHLKW	MOBERLY LAKE	TELEGRAPH CREEK
BRALORNE	GOLD BRIDGE	MOUNT CURRIE	TINTAGEL
BRITANNIA BEACH	GOLD RIVER	MUD BAY	TLELL
BUCKLEY BAY	GOLDEN	NAKUSP	TOPLEY
BURTON	GRAND HAVEN	NEW AIYANSH	TWO MILE
CANAL FLATS	GUN LAKE	NORTH BEND	UCLUELET
CASSIDY	HAGENSBORG	PEMBERTON	VANANDA
CELISTA	HARRISON MILLS	PINE VALLEY	WASA LAKE
CHARLIE LAKE	HEMLOCK VALLEY	PORT HARDY	WILLOW RIVER
CHERRYVILLE	HERIOT BAY	PORT MCNEILL	WILMER
COAL HARBOUR	HOLBERG	PORT RENFREW	WINDERMERE
D'ARCY	HONEYMOON BAY	PRESPATOU	WINTER HARBOUR
DEASE LAKE	HORSEFLY	QUALICUM BEACH	WOSS
DECKER LAKE	INVERMERE	QUATHIASKI COVE	YAHK
DEEP BAY	KELLY LAKE	QUATSINO	YALE
DEROCHE	LAIDLAW	ROLLA	YOUBOU
DEVINE	LAKE COWICHAN	SACHTEEN	

49.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, p. 5-70 RIB Rate Report Proceeding – cross-subsidy

The Application that "BC Hydro will assess the possibility of the RIB rate causing a 'cross-subsidy between customers with and without access to natural gas service' posed by Minister RIB Report Letter question 1 using cost of service information."

In the Commission's RIB Rate Report proceeding, BCOAPO's Submission dated October 16, 2015, states on page 7 that: "Both companies' COS analyses require detailed load data, including not only customer counts and energy use but also non-coincident peak (NCP) and coincident peak (CP) data for each of the groups being assessed."

In the Commission's RIB Rate Report proceeding, BCOAPO's Submission dated October 16, 2015, states on pages 14 to 15 that:

BCOAPO assumes that [the Minister] refers to intra-class cross-subsidy. BCOAPO considers it most likely that such cross-subsidy will exist within many residential rate classes… should the Commission determine that the RIB rates do actually cause cross-subsidy between customers with and without access to natural gas, and that the cross-subsidy is significant, BCOAPO wonders what relevance such a finding would have.

In the Commission's RIB Rate Report Proceeding, Mr. Marty's Submission dated October 16, 2015, states on page 2 that: "Question 1 can only be answered by comparing the revenue flows under the Residential Conservation Rate, as currently structured, with a theoretical two-Tier pricing system in which each and every resident experiences the same percentage of electricity consumption in Block 2."

1.49.1 Please confirm that BC Hydro will examine <u>intra</u>-rate class cross-subsidy based on "with" and "without" access to natural gas in its report for the Minister's Question 1, using a cost of service approach, including examining demand and energy costs.

RESPONSE:

Confirmed. To determine whether a cross-subsidy exists BC Hydro anticipates that it would calculate the cost of serving Residential customers with and without access to natural gas, including energy and demand costs. BC Hydro anticipates that its analysis would include calculating the costs of serving both groups on a cents/kWh basis along with R/C ratios for both groups under the existing RIB rate.

49.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, p. 5-70
RIB Rate Report Proceeding – cross-subsidy

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1.49.1.1 Please comment on the usefulness of BC Hydro including in the report on Question 1 a discussion of intra-class subsidy in general and the usefulness and relevance of any finding on intra-class subsidy from the report.

RESPONSE:

In BC Hydro's response to BCUC IR 1.63.1, BC Hydro expresses its view that the Bonbright fair apportionment of costs among customers criterion applies to both inter-rate class and intra-rate class.

As described on lines 6 to 8 on page 5-70 of Exhibit B-1, BC Hydro will assess the possibility of the RIB rate causing a cross-subsidy between customers with and without natural gas service. However, given the wording of Minister RIB Report Letter Question 1, the RIB Report should not engage in a broad reaching discussion generally on intra-class cross-subsidy.

49.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, p. 5-70 RIB Rate Report Proceeding – cross-subsidy

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In the Commission's RIB Rate Report Proceeding, Mr. Marty's Submission dated October 16, 2015, states on page 2 that: "Question 1 can only be answered by comparing the revenue flows under the Residential Conservation Rate, as currently structured, with a theoretical two-Tier pricing system in which each and every resident experiences the same percentage of electricity consumption in Block 2."

1.49.1.2 Please comment on the feasibility and usefulness of the Commission requesting BC Hydro's comments in the report on the Minister's questions about potential cross-subsidy created by the impact of natural gas prices on electricity consumption for those with access to natural gas.

RESPONSE:

BC Hydro does not believe it is useful for the Commission to request comments in the RIB Rate Report related to a potential cross-subsidy created by the impact of natural gas prices on electricity consumption for customers with access to natural

gas. The Minister RIB Report Letter questions concern the potential impact of the RIB rate on customers without access to natural gas.

With respect to the feasibility of such analysis BC Hydro notes it would require a significant amount of time and labour to develop an econometric model whereby the demand for electricity is a function of number of factors' including the historic price of natural gas.

Please also refer to BC Hydro's response to BCUC IR 1.47.2.3.

49.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, p. 5-70
RIB Rate Report Proceeding – cross-subsidy

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1.49.2 Please provide BC Hydro's position on BCOAPO's submission on the cost of service analysis required and specifically the use of CP and NCP. Please explain if adequate data regarding NCP and CP is available.

RESPONSE:

In BC Hydro's view BCOAPO's approach is not feasible during the RDA evidentiary phase. To undertake an analysis of subsidization between subsets of customers, BC Hydro would require the allocation factors it currently uses in its COS methodology. These include energy, coincident peak, non-coincident peak and customer count. The use of CP and NCP allocators would appropriately assign electric heating users' portion of peak system use and the associated demand costs.

49.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, p. 5-70
RIB Rate Report Proceeding – cross-subsidy

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1.49.3 Please provide comment on Mr. Marty's submission above.

RESPONSE:

In BC Hydro's view, Mr. Marty's submission will yield no meaningful insights into cross-subsidy beyond BC Hydro's proposal with respect to the Minister RIB Report Letter Question 1 on Exhibit B-1, page 5-70.

All rate design alternatives are priced to recover the same revenue. That is, they are all revenue neutral to the status quo forecasted target revenue on forecasted load, as stated on Exhibit B-1, Appendix H-1A, page 2 and shown in Exhibit B-1, Appendix H-1A, sections 5 to 8. This is also discussed in Workshop 3 (Exhibit B-1, Appendix C-3A, page 29 of 184).

If Mr. Marty's reference of "consumption" is defined as the customer's billed consumption on each and every bill, then Mr. Marty's suggestion of a "theoretical

two-tier pricing system" would effectively yield the same customer bills as a flat rate for each customer.

If Mr. Marty's reference of "consumption" is defined as a fixed kWh amount, such as historical consumption, then this design is of the concept of a Customer Specific Baseline Rate. The baseline design has been discussed in Workshop 3 (Exhibit B-1, Appendix C-3A, pages 43 to 47 of 184), and in Workshop 3 considerations memo section 2.3 (Exhibit B-1, Appendix C-3A, page 106 and 107 of 184). BC Hydro's conclusion, which is also supported by COPE 378 and BCESA, is that the Customer Specific Baseline Rate is impractical due to the large number of customers, and will impose significant implementation challenges.

50.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, p. 5-71
RIB Rate Report Proceeding – Minister's Question 3
High energy use and bill impacts

In the Commission's RIB Rate Report proceeding, BCSEA's Submission dated October 16, 2015, BCSEA states on page 6 that:

BCSEA-SCBC recommend that the Commission clarify or confirm that there are two subject groups in question 3: (a) customers, regardless of income, without access to natural gas, and (b) low income customers without access to natural gas. If confirmed, note that this is different than in question 2, where the subject group is low income customers with and without access to natural gas (i.e. low income customers in all areas of the utility's service territory).

In the Commission's RIB Rate Report Proceeding, Mr. Marty's Submission dated October 16, 2015, states on page 3 that:

it is essential that FBC incorporate the other major factors affecting the electricity consumption of these two end-uses for which they have data; particularly, outside temperatures, water heating fuel and secondary home heating fuel… FBC should be directed to examine samples of residences that consume around 30,000 kWh/year, 20,000 kWh/year and 10,000 kWh/year and explain, to the fullest extent possible, the differences in electricity consumption among them. In addition to responding to the Minister's Question 3, such analysis could shed light on how much of the differences in electricity use among customers might be due to the level of household energy efficiency, which is important for addressing Questions 4 and 5.

1.50.1 Please confirm that BC Hydro will report on the Minister's Question 3 using the two groups as defined by BCSEA and that BC Hydro will report on the factors that lead to high energy use for each of these two groups.

RESPONSE:

Confirmed with respect to the two groups. In section 5.5.2 of Exhibit B-1, BC Hydro listed the three main factors that drive higher than average annual electricity consumption (heating fuel; housing type within region) of the phrase "high-energy use". However, exploring all factors that can lead to "high energy use" will require a precise definition of what "high energy use" is.

50.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

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1.50.2 Please comment on the feasibility or usefulness of reporting on factors such as temperature, water heating fuel and secondary heating fuel as suggested by Mr. Marty. Does BC Hydro have these data?

RESPONSE:

Testing variables such as temperature (in the context of cooling degree days and heating degree days in broad geographic regions and not Mr. Marty's suggestion that this analysis be undertaken with a location specificity such as residences at different altitudes), water heating fuel, and secondary heating fuel is feasible. BC Hydro notes that the three factors it has advanced for purposes of responding Minister RIB Report Letter Question 3 include housing type within region and thus captures regional temperature variation. BC Hydro considers that heating fuel and housing type within region are bigger factors than water heating fuel and secondary heating fuel.

50.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

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1.50.3 Please comment on the feasibility and usefulness of BC Hydro examining sample residences that consume 30,000 kWh/year, 20,000 kWh/year and 10,000 kWh/year.

RESPONSE:

The analysis is feasible and BC Hydro could attempt to deduce general observations about residences that consume at 30,000, 20,000, and 10,000 kWh. However, the usefulness of the observations may be limited by the small sample size of the higher kWh residences due to the low incidence of residences that consume at those levels.

50.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

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In the Commission's RIB Rate Report Proceeding, Mr. Marty's Submission dated October 16, 2015, states on page 3 that:

it is essential that FBC incorporate the other major factors affecting the electricity consumption of these two end-uses for which they have data; particularly, outside temperatures, water heating fuel and secondary home heating fuel… FBC should be directed to examine samples of residences that consume around 30,000 kWh/year, 20,000 kWh/year and 10,000 kWh/year and explain, to the fullest extent possible, the differences in electricity consumption among them. In addition to responding to the Minister's Question 3, such analysis could shed light on how much of the differences in electricity use among customers might be due to the level of household energy efficiency, which is important for addressing Questions 4 and 5.

1.50.3.1 Will BC Hydro be able to make any general observations about residences with the consumption levels suggested by Mr. Marty? If not, why not?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.50.3.

50.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, p. 5-71
RIB Rate Report Proceeding – Minister's Question 3
High energy use and bill impacts

In the Commission's RIB Rate Report proceeding, BCSEA's Submission dated October 16, 2015, BCSEA states on page 6 that:

BCSEA-SCBC recommend that the Commission clarify or confirm that there are two subject groups in question 3: (a) customers, regardless of income, without access to natural gas, and (b) low income customers without access to natural gas. If confirmed, note that this is different than in question 2, where the subject group is low income customers with and without access to natural gas (i.e. low income customers in all areas of the utility's service territory).

In the Commission's RIB Rate Report Proceeding, Mr. Marty's Submission dated October 16, 2015, states on page 3 that:

it is essential that FBC incorporate the other major factors affecting the electricity consumption of these two end-uses for which they have data; particularly, outside temperatures, water heating fuel and secondary home heating fuel… FBC should be directed to examine samples of residences that consume around 30,000 kWh/year, 20,000 kWh/year and 10,000 kWh/year and explain, to the fullest extent possible, the differences in electricity consumption among them. In addition to responding to the Minister's Question 3, such analysis could shed light on how much of the differences in electricity use among customers might be due to the level of household energy efficiency, which is important for addressing Questions 4 and 5.

1.50.3.2 Please comment where the analysis suggested by Mr. Marty could shed light on how much of the differences in electricity use among customers might be due to the level of household energy efficiency.

RESPONSE:

Understanding household efficiency is a distinctly different research question than what is causing high energy consumption. For example, a fully occupied large property with efficient LED lighting and energy star appliances can still have high energy consumption.

An important component of understanding household energy efficiency is consumer behavior, which requires complex economic surveys to investigate, and cannot be deduced by observing end-uses in residences in the analysis suggested by Mr. Marty.

50.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, p. 5-71
RIB Rate Report Proceeding – Minister's Question 3
High energy use and bill impacts

In the Commission's RIB Rate Report proceeding, BCSEA's Submission dated October 16, 2015, BCSEA states on page 6 that:

BCSEA-SCBC recommend that the Commission clarify or confirm that there are two subject groups in question 3: (a) customers, regardless of income, without access to natural gas, and (b) low income customers without access to natural gas. If confirmed, note that this is different than in question 2, where the subject group is low income customers with and without access to natural gas (i.e. low income customers in all areas of the utility's service territory).

In the Commission's RIB Rate Report Proceeding, Mr. Marty's Submission dated October 16, 2015, states on page 3 that:

it is essential that FBC incorporate the other major factors affecting the electricity consumption of these two end-uses for which they have data; particularly, outside temperatures, water heating fuel and secondary home heating fuel… FBC should be directed to examine samples of residences that consume around 30,000 kWh/year, 20,000 kWh/year and 10,000 kWh/year and explain, to the fullest extent possible, the differences in electricity consumption among them. In addition to responding to the Minister's Question 3, such analysis could shed light on how much of the differences in electricity use among customers might be due to the level of household energy efficiency, which is important for addressing Questions 4 and 5.

1.50.4 Please confirm whether BC Hydro will provide actual numbers of low income customers that would be worse off under a flat rate, in addition to percentages.

RESPONSE:

BC Hydro cannot provide actual numbers of low income customers that would be worse off under a flat rate because BC Hydro's billing data does not collect income information, which is necessary to produce this result. Table 5-3 and Table 5-4 of Exhibit B-1 show the proportions better off than status quo RIB rate and proportions higher than 10 per cent and 20 per cent bill impact for low income customers, as estimated from the REUS data sample where the income is self-reported and any given household's low-income status is predicted or

derived. One may be able to do rough estimates on numbers using the REUS information.

51.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.6 BC Hydro Residential Demand Side Management Programs, pp. 5-72-78
RIB Rate Report Proceeding – Minister's Questions 4 and 5
Demand-side management programs

In the Commission's RIB Rate Report proceeding, FortisBC Inc.'s submission dated September 30, 2015, states on page 5:

The Company proposes to provide a list and brief description of existing programs that customers can participate in that can impact the factors identified in response to question 3 above that lead to high energy use…The Company will provide a discussion of any potential additional DSM programs, or potential modifications to existing programs, that could be undertaken within the existing regulatory environment.

In the Commission's RIB Rate Report Proceeding, BCSEA's submission dated October 16, 2015, states on page 6: "BCSEA-SCBC recommend that the Commission clarify that the core of question 4 is what is the potential for existing DSM programs to reduce electricity usage and hence customer bills. For example, what is the potential for an existing DSM program to be ramped up, say with higher incentives, in order to achieve increased energy savings?"

In the Commission's RIB Rate Report Proceeding, Mr. Marty's Submission dated October 16, 2015, states on page 3:

The potential for FBC's existing DSM programs to mitigate the electricity bill impacts of the RCR depends on two factors:

- energy inefficiency must account for a significant portion of the household's higher electricity consumption; and
- the household must be contemplating a renovation or replacement of aging energy-using equipment (such as the hot water heater or space heating system).

In the Commission's RIB Rate Report Proceeding, BCOAPO Submission dated October 16, 2015, states on page 13: "…it would be helpful for the companies to comment on whether DSM measures that they each propose would run contrary to the prescribed fuel switching guidelines."

1.51.1 Please confirm that BC Hydro will report on the Minister's Questions 4 and 5 as FortisBC Inc. has proposed.

RESPONSE:

In BC Hydro's view, the Minister RIB Report Letter Questions 1 to 5 call for a two-phased review of BC Hydro's RIB rate. This is clear from Question 4, which asks: "What is the potential for existing [DSM] programs to mitigate these *impacts*" [emphasis added].

First, is there evidence that the RIB rate has high bill impacts on the following BC Hydro Residential customer segments, with the phrase "high bill impacts" defined in the Minister RIB Report Letter to mean "over 10 per cent":

1. **BC Hydro's low income customers (Question 2) – No stakeholder submitting comments in the Commission's RIB Report proceeding contests that low incomers should be defined for RIB Report purposes using Statistics Canada's LICO; using pre-tax income levels LICO, the answer to this question is no under either of the two RIB rate F2017 to F2019 pricing principle options discussed in section 5.2.5.1 of Exhibit B-1:**

   - **Under BC Hydro's proposed RIB rate pricing principle Option 1, no low income customer will have a bill impact greater than 10 per cent (Exhibit B-1, page 5-71, lines 8-13);**

   - **Under RIB rate pricing principle Option 2, no low income customers will have a bill impact greater than 10 per cent (Exhibit B-1, Figures 5-20 and 5-23).**

   In addition, only 9 per cent of low income customers would be better off under a flat rate as compared to a RIB rate (refer to Table 5-4 of Exhibit B-1).

2. **BC Hydro's customers without access to natural gas, including low income customers (Question 3) – BC Hydro accepts that there is some uncertainty as to the definition of customers without access to natural gas. The answer is no under either of the two RIB rate F2017 to F2019 pricing principle options discussed in section 5.2.5.1 of Exhibit B-1 if BC Hydro uses customers whose primary space heating source is electricity as a proxy for customers without access to natural gas:**

   - **Under BC Hydro's proposed RIB rate pricing principle Option 1, no customer whose primary space heating source is electricity or low income customer whose primary space heating source is electricity will have a bill impact greater than 10 per cent (Exhibit B-1, Table 5-8); and**

   - **Under RIB rate pricing principle Option 2, no customer whose primary space heating source is electricity or low income customer whose primary space heating source is electricity will have a bill impact greater than 10 per cent (Exhibit B-1, Figures 5-20 and 5-23).**

The key issue for this phase 1 review is how to define customers without access to natural gas. As indicated at section 5.5.3 of Exhibit B-1, page 5-70, BC Hydro proposes a community approach to this issue, and will model the impacts of moving from the RIB rate to flat rate for customers in communities without access to natural gas (Exhibit B-1, page 5-71, lines 23-27).

Second, and only if the answer to the first question is yes for one or both of the residential customer segments, BC Hydro would report on Questions 4 and Question 5 as FortisBC has proposed. BC Hydro notes that FortisBC referenced a critical qualifier to the Question 4 and Question 5 examination, which is "within the existing regulatory environment". As noted by BC Hydro at pages 5-72 to 5-73 of Exhibit B-1, the phrase "within the existing regulatory environment" must take into account the F2017 to F2019 rate caps set out in section 9 of Direction No. 7, and also the fact that the venue for any assessment of DSM program-related expenditures is a section 44.2 *UCA* DSM expenditure schedule determination filing. BC Hydro will be submitting a DSM

expenditure schedule determination filing contemporaneously with or as part of the F2017 RRA filing in February 2016, and this filing must be considered as part of Question 4 and Question 5.

51.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.6 BC Hydro Residential Demand Side Management Programs, pp. 5-72-78
RIB Rate Report Proceeding – Minister's Questions 4 and 5
Demand-side management programs

In the Commission's RIB Rate Report proceeding, FortisBC Inc.'s submission dated September 30, 2015, states on page 5:

The Company proposes to provide a list and brief description of existing programs that customers can participate in that can impact the factors identified in response to question 3 above that lead to high energy use…The Company will provide a discussion of any potential additional DSM programs, or potential modifications to existing programs, that could be undertaken within the existing regulatory environment.

In the Commission's RIB Rate Report Proceeding, BCSEA's submission dated October 16, 2015, states on page 6: "BCSEA-SCBC recommend that the Commission clarify that the core of question 4 is what is the potential for existing DSM programs to reduce electricity usage and hence customer bills. For example, what is the potential for an existing DSM program to be ramped up, say with higher incentives, in order to achieve increased energy savings?"

In the Commission's RIB Rate Report Proceeding, Mr. Marty's Submission dated October 16, 2015, states on page 3:

The potential for FBC's existing DSM programs to mitigate the electricity bill impacts of the RCR depends on two factors:

- energy inefficiency must account for a significant portion of the household's higher electricity consumption; and
- the household must be contemplating a renovation or replacement of aging energy-using equipment (such as the hot water heater or space heating system).

In the Commission's RIB Rate Report Proceeding, BCOAPO Submission dated October 16, 2015, states on page 13: "…it would be helpful for the companies to comment on whether DSM measures that they each propose would run contrary to the prescribed fuel switching guidelines."

1.51.2 Please comment on BCSEA's recommendation above.

RESPONSE:

BC Hydro does not agree that the core of Minister RIB Report Letter Question 4 is as open-ended as "what is the potential for existing DSM programs to reduce electricity usage and hence customer bills". First, the RIB Report is to focus on three residential customer segments: (1) low income customers; (2) customers without access to natural gas; and (3) low income customers without natural gas. Second, in BC Hydro's view there must first be a finding that the RIB rate will result in bill impacts greater than 10 per cent for these three residential customer segments. In this regard, please refer to BC Hydro's response to BCUC IR 1.51.1.

BC Hydro also submits that the RIB Rate Report proceeding is not the appropriate place to examine the potential for an existing DSM program "to be ramped up" to achieve increased energy savings. The overall need for increased energy savings is a long-term planning question to be addressed through BC Hydro's IRP process.

51.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.6 BC Hydro Residential Demand Side Management Programs, pp. 5-72-78
RIB Rate Report Proceeding – Minister's Questions 4 and 5
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- the household must be contemplating a renovation or replacement of aging energy-using equipment (such as the hot water heater or space heating system).

In the Commission's RIB Rate Report Proceeding, BCOAPO Submission dated October 16, 2015, states on page 13: "…it would be helpful for the companies to comment on whether DSM measures that they each propose would run contrary to the prescribed fuel switching guidelines."

1.51.3 Please confirm whether BC Hydro will report on the Minister's Question 4 using the two groups proposed by BCSEA: "(a) customers, regardless of income, without access to natural gas, and (b) low income customers without access to natural gas."

RESPONSE:

Confirmed, subject to BC Hydro's considerations outlined in BC Hydro's response to BCUC IR 1.51.1 (requirement to find the RIB rate results in bill impacts of greater than 10 per cent on low income customers and/or customers without access to natural gas) and BCUC IR 1.48.2 (defining customers without access to natural gas).

51.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.6 BC Hydro Residential Demand Side Management Programs, pp. 5-72-78
RIB Rate Report Proceeding – Minister's Questions 4 and 5
Demand-side management programs

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- energy inefficiency must account for a significant portion of the household's higher electricity consumption; and
- the household must be contemplating a renovation or replacement of aging energy-using equipment (such as the hot water heater or space heating system).

In the Commission's RIB Rate Report Proceeding, BCOAPO Submission dated October 16, 2015, states on page 13: "…it would be helpful for the companies to comment on whether DSM measures that they each propose would run contrary to the prescribed fuel switching guidelines."

1.51.4 Please comment on the feasibility and usefulness of an analysis of the two factors suggested by Mr. Marty.

RESPONSE:

With respect to Mr. Marty's first factor, household efficiency, please refer to BC Hydro's response to BCUC IR 1.50.3.2.

Mr. Marty's second factor, which entails details concerning each household, is akin to a residential customer baseline rate. The challenges of such a rate are discussed in BC Hydro's response to BCUC IR 1.49.3, the Workshop 3 presentation (Exhibit B-1, Appendix C-3A, pages 43 to 47 of 184), and in the Workshop 3 consideration memo, section 2.3 (Exhibit B-1, Appendix C-3A, page 106 and 107 of 184).

51.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.6 BC Hydro Residential Demand Side Management Programs, pp. 5-72-78
RIB Rate Report Proceeding – Minister's Questions 4 and 5
Demand-side management programs

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In the Commission's RIB Rate Report Proceeding, BCSEA's submission dated October 16, 2015, states on page 6: "BCSEA-SCBC recommend that the Commission clarify that the core of question 4 is what is the potential for existing DSM programs to reduce electricity usage and hence customer bills. For example, what is the potential for an existing DSM program to be ramped up, say with higher incentives, in order to achieve increased energy savings?"

In the Commission's RIB Rate Report Proceeding, Mr. Marty's Submission dated October 16, 2015, states on page 3:

The potential for FBC's existing DSM programs to mitigate the electricity bill impacts of the RCR depends on two factors:

- energy inefficiency must account for a significant portion of the household's higher electricity consumption; and
- the household must be contemplating a renovation or replacement of aging energy-using equipment (such as the hot water heater or space heating system).

In the Commission's RIB Rate Report Proceeding, BCOAPO Submission dated October 16, 2015, states on page 13: "…it would be helpful for the companies to comment on whether DSM measures that they each propose would run contrary to the prescribed fuel switching guidelines."

1.51.5 Please comment on the feasibility and usefulness of BC Hydro indicating which of its existing or potential DSM programs could result in fuel switching from electricity to natural gas.

RESPONSE:

There is no utility in indicating which of BC Hydro's existing or potential DSM programs could result in fuel switching from electricity to natural gas because no such programs have as their main purpose the encouragement of such fuel switching. Subsection 1(1) of the *CEA* defines demand-side measure as:

> **"a rate, measure, action or program undertaken**
>
> **(a) to conserve energy or promote energy efficiency,**
>
> **(b) to reduce the energy demand a public utility must serve, or**
>
> **(c) to shift the use of energy to period of lower demand,**
>
> **but does not include**
>
> **(d) <u>a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in BC</u> [emphasis added], or**
>
> **(e) any rate, measure, action or program prescribed.**

As noted in BC Hydro's response CEBC IR 1.2.1, while there may be some minor impact on natural gas consumption resulting from cross effects that occur with some of BC Hydro's DSM programs, BC Hydro's DSM programs are consistent with the *CEA* definition of DSM.

51.0 D. CHAPTER 5 – RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Application, Section 5.6 BC Hydro Residential Demand Side Management Programs, pp. 5-72-78
RIB Rate Report Proceeding – Minister's Questions 4 and 5 Demand-side management programs

In the Commission's RIB Rate Report proceeding, FortisBC Inc.'s submission dated September 30, 2015, states on page 5:

The Company proposes to provide a list and brief description of existing programs that customers can participate in that can impact the factors identified in response to question 3 above that lead to high energy use…The Company will provide a discussion of any potential additional DSM programs, or potential modifications to existing programs, that could be undertaken within the existing regulatory environment.

In the Commission's RIB Rate Report Proceeding, BCSEA's submission dated October 16, 2015, states on page 6: "BCSEA-SCBC recommend that the Commission clarify that the core of question 4 is what is the potential for existing DSM programs to reduce electricity usage and hence customer bills. For example, what is the potential for an existing DSM program to be ramped up, say with higher incentives, in order to achieve increased energy savings?"

In the Commission's RIB Rate Report Proceeding, Mr. Marty's Submission dated October 16, 2015, states on page 3:

The potential for FBC's existing DSM programs to mitigate the electricity bill impacts of the RCR depends on two factors:

- energy inefficiency must account for a significant portion of the household's higher electricity consumption; and
- the household must be contemplating a renovation or replacement of aging energy-using equipment (such as the hot water heater or space heating system).

In the Commission's RIB Rate Report Proceeding, BCOAPO Submission dated October 16, 2015, states on page 13: "…it would be helpful for the companies to comment on whether DSM measures that they each propose would run contrary to the prescribed fuel switching guidelines."

1.51.6 Please comment on the feasibility and usefulness of the Commission requesting BC Hydro to identify in its report on the Minister's questions any population(s) that have no access to natural gas, high electricity use and a) no access to DSM programs; and b) no access to DSM programs, and are low income.

RESPONSE:

All BC Hydro Residential customers have access to a number of Residential DSM programs. Therefore, it is BC Hydro's view that it is not useful for purposes of responding to the Minister RIB Report Letter to identify any population(s) that have no access to natural gas, high electricity use and (a) no access to DSM programs and (b) no access to DSM programs and are low income, because there are no such populations.

52.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.1 General Service, p. 6-3 RS 1278

BC Hydro proposes no change to RS 1278. This rate was not reviewed in the 2015 RDA stakeholder engagement process and therefore specific engagement with the customer did not occur. Accordingly, BC Hydro believes it would be inappropriate to eliminate RS 1278 at this time.

1.52.1 This rate has only one customer and has been closed since the 1970s. Please explain whether BC Hydro would discuss its elimination in module two?

RESPONSE:

BC Hydro would need to assess the customer's current situation and potential rate options before making this decision.

52.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.1 General Service, p. 6-3 RS 1278

BC Hydro proposes no change to RS 1278. This rate was not reviewed in the 2015 RDA stakeholder engagement process and therefore specific engagement with the customer did not occur. Accordingly, BC Hydro believes it would be inappropriate to eliminate RS 1278 at this time.

1.52.2 Is electricity sold to this customer below allocated cost? If so, what rate design principles are achieved by continuing at this rate?

RESPONSE:

RS 1278 originated with one of BC Hydro's predecessor companies, BC Electric, in the 1920s. The rate was designed to encourage industrial development, specifically electric arc furnaces. This rate was closed in the 1970s and was reviewed by the BCUC in the 1991 RDA, as BC Hydro had proposed to increase the rates by ten per cent annually until rate equity occurred with the then-standard default rate. The BCUC's 1991 RDA Decision (Commission Order No. G-36-92) did not approve the rate increase but determined that BC Hydro may terminate rate availability when there is a change in ownership or use.

Please also refer to BC Hydro's response to BCUC IR 1.52.1.

53.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.2.3.1 SGS Rate Structure, pp. 6-8, 6-10
SGS's flat energy rate

The flat energy rate of 11.01 cents/kWh (F2017) as proposed by BC Hydro is within BC Hydro's energy LRMC range (upper bound is 11.13 cents/kWh for F2017).

BC Hydro is proposing a one-time increase to the RS 13xx basic charge to 45 percent recovery of customer-related costs attributable to the SGS class in the F2016 study, and a one-time offsetting reduction of the energy rate in order to maintain revenue neutrality.

1.53.1 On page 22 of the Consideration Memo in Tab Workshop 11(a)/11(b) in Appendix C4, BC Hydro states that the SGS and RIB basic charges do not recover any demand-related costs. Demand-related costs are recovered through the respective SGS flat energy rate and RIB rate Step 1 and Step 2 energy rates. Approximately what percentage of the proposed flat energy rate of 11.01 cents/kWh is demand cost recovery?

RESPONSE:

For purposes of this response, BC Hydro assumes: 1) that the F2016 COS is applicable to F2017; and 2) that F2017 SGS revenue would exactly match the SGS F2016 COS.

Table 1 reports the Total F2016 costs assigned to the SGS class, as provided in sheet 4.1 of the F2016 COS excel file attached in Appendix E of Exhibit B-1:

Table 1: Total F2016 costs assigned to the SGS class:

	($ million)	**(%)**
SGS Energy-related costs	**140.0**	**38.0**
SGS Demand-related costs	**182.7**	**49.7**
SGS Customer-related costs	**45.2**	**12.3**
Total	**367.9**	**100.0**

Under BC Hydro's proposed one-time increase to the SGS basic charge to 45 per cent recovery of customer-related costs, the SGS energy charge is

therefore forecast to recover 100 per cent of energy-related costs, 100 per cent of demand-related costs and 55 per cent of customer-related costs.

Fifty-two per cent of the proposed SGS flat energy rate of 11.01 cents/kWh F2017 is expected to recover demand-related costs as reported in Table 2 below:

Table 2: SGS costs recovered in the SGS energy rate:

	($ million)	(%)
SGS Energy-related costs	**140.0**	**40.3**
SGS Demand-related costs	**182.7**	**52.6**
SGS Customer-related costs	**24.9**	**7.1**
Total	**347.6**	**100.0**

53.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.2.3.1 SGS Rate Structure, pp. 6-8, 6-10
SGS's flat energy rate

The flat energy rate of 11.01 cents/kWh (F2017) as proposed by BC Hydro is within BC Hydro's energy LRMC range (upper bound is 11.13 cents/kWh for F2017).

BC Hydro is proposing a one-time increase to the RS 13xx basic charge to 45 percent recovery of customer-related costs attributable to the SGS class in the F2016 study, and a one-time offsetting reduction of the energy rate in order to maintain revenue neutrality.

1.53.2 BC Hydro is proposing an increase of basic charge for SGS customers to 45 percent recovery of customer-related costs. This recovery percentage is similar to the RIB basic charge recovery (see page 5-41). Approximately what percentage of the proposed energy rates of RIB step 1 and step 2 is demand cost recovery?

RESPONSE:

For purposes of this response, BC Hydro assumes: 1) that the F2016 COS is applicable to F2017; and 2) that F2017 Residential revenue would exactly match the Residential F2016 COS.

Table 1 reports the Total F2016 costs assigned to the Residential class, as provided in sheet 4.1 of the F2016 COS excel file attached in Appendix E of Exhibit B-1

Table 1: Total F2016 costs assigned to the Residential class:

	($ million)	**(%)**
Residential Energy-related costs	**708.4**	**34.7**
Residential Demand-related costs	**1,060.6**	**51.9**
Residential Customer-related costs	**273.4**	**13.4**
Total	**2,042.4**	**100.0**

Residential energy rates are forecast to recover 100 per cent of energy-related costs, 100 per cent of demand-related costs and 55 per cent of customer-related costs (given Residential basic charge recovery of 45 per cent).

Fifty-five per cent of the proposed RIB energy rates in F2017 is expected to recover demand-related costs as reported in Table 2 below:

Table 2: Residential costs recovered in RIB energy rates:

	($ million)	(%)
Residential Energy-related costs	**708.4**	**36.9**
Residential Demand-related costs	**1,060.6**	**55.3**
Residential Customer-related costs	**150.3**	**7.8**
Total	**1919.3**	**100.0**

Forecast F2017 revenues from Residential energy rates are roughly evenly split between the proposed Step 1 and Step 2 rates (48 per cent and 52 per cent, respectively), as shown in Table H-1A-4 in Appendix H-1A of Exhibit B-1.

53.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.2.3.1 SGS Rate Structure, pp. 6-8, 6-10
SGS's flat energy rate

The flat energy rate of 11.01 cents/kWh (F2017) as proposed by BC Hydro is within BC Hydro's energy LRMC range (upper bound is 11.13 cents/kWh for F2017).

BC Hydro is proposing a one-time increase to the RS 13xx basic charge to 45 percent recovery of customer-related costs attributable to the SGS class in the F2016 study, and a one-time offsetting reduction of the energy rate in order to maintain revenue neutrality.

1.53.3 If the Commission were to consider including a capacity value to the LRMC as more appropriate, does BC Hydro agree that the proposed recovery of customer-related costs be reduced to a lower level so that the flat rate can be increased to be closer to the LRMC?

RESPONSE:

No. As set out in BC Hydro's response to BCUC IR 1.11.1, there is no basis for including a generation capacity value in the energy LRMC for purposes of assessing the SGS flat energy rate. The SGS flat energy rate results from the allocation of embedded energy, demand and customer-related costs, and is not intended to signal BC Hydro's energy LMRC.

BC Hydro observes that the proposed SGS flat energy rate is reflective of the energy LRMC for F2017-2019 period.

54.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.2.3.2, 6.2.4 & Workshop 11A, Slide 25 Small General Service, p. 6-12 & Slide 25
Small General Service Basic Charge

BC Hydro proposes to increase the SGS basic charge

… from about 33 per cent to a level comparable to the RIB rate basic charge customer-related cost recovery of about 45 per cent (F2016 COS). As set out in Table 3-7 in Chapter 3, Residential and SGS customer cost allocation is similar, as are energy and demand cost allocations. BC Hydro concluded that the RIB rate basic charge customer-related cost recovery level is the appropriate reference.

BC Hydro also states that only COPE 378 does not support an increase to the SGS basic charge cost recovery since it is directionally counter to energy conservation.

1.54.1 How will the proposed basic charges for SGS compare to the proposed basic charges for LGS and MGS customers in terms of customer cost allocation?

RESPONSE:

F2017 forecast recovery through basic charges of the customer-related costs assigned to the MGS and LGS classes are 9 per cent and 7 per cent, respectively. BC Hydro has proposed no changes to the MGS or LGS basic charges in terms of the percentage of customer-related costs that they recover. In comparison, the existing SGS basic charge recovers about 35 per cent of customer-related costs, and under BC Hydro's proposal would recover about 45 per cent of such costs.

It is not meaningful to compare the level of customer-related cost recovery in the SGS basic charge to that of the MGS or LGS basic charges, for the following reasons:

- **Customer-related cost recovery is a minor consideration in MGS and LGS rate design, particularly given BC Hydro's objective to improve the fairness in the design and fixed cost recovery of the demand charges. For SGS, on the other hand, consideration of the relative fairness in cost recovery is only focused on the basic versus energy charges, given that demand charges are not practical or appropriate for this class (refer to section 6.2.3.1 of Exhibit B-1, pages 6-10 to 6-11) and thus SGS demand-related costs are recovered through the SGS flat energy rates;**

- **MGS and LGS rates recover a portion of fixed costs through their respective demand charges. BC Hydro defines fixed costs as:**
    - **Demand-related costs, which are determined in the F2016 COS study and are comprised of generation demand, transmission demand and distribution demand-related costs; and**
    - **Customer-related costs, which are comprised of: i) distribution costs that have been classified as customer-related; that is, metering, services and a portion of transformer costs; and ii) customer care related costs; that is, billing and call center costs, etc.**

As shown in Table 3-7 of Exhibit B-1, and as reviewed on page 6-12 of Exhibit B-1, Residential and SGS customer-related cost allocations are similar, as are energy and demand cost allocations. BC Hydro concluded that RIB rate basic charge customer-related cost recovery is the appropriate reference for comparison to the SGS basic charge. For the reasons described in section 6.2 of Exhibit B-1, pages 6-12 to 6-13, BC Hydro is of the view that there are no rate design objectives to be traded off in its proposal to increase the level of the SGS basic charge to recover 45 per cent of customer-related costs.

55.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.2.4 Small General Service, Table 6-3
Small General Service bill impacts

Table 6-3 shows that the bill impacts from the increase in basic charge is minimal for most customers, although the impact on the smallest customer and the lowest 10 percent of customers exceed BC Hydro's 10 percent bill impact amber signal.

1.55.1 How many customers are impacted in the lowest 10 percent group of customers? Is there anything BC Hydro would propose to minimize the bill impact on these customers?

RESPONSE:

Before responding, BC Hydro attaches a revised Table 6-3A to replace Table 6-3 of Exhibit B-1, correcting the highlighted bill impacts for the 70th, 80th, 90th and Maximum consumption thresholds. The highlighted metrics are negative in Table 6-3, but should have listed as positive.

Table 6-3A Annual Bill Impacts of an Increase in the SGS Basic Charge to Recover 45 per cent of Customer-related Costs

Percentile by Consumption	Annual kWh	F2017 Annual Bill Status Quo ($)	F2017 Annual Bill BC Hydro Proposal ($)	Annual Bill Difference between F2017 BC Hydro Proposal and F2017 Status Quo ($)	Annual Bill Difference between F2017 BC Hydro Proposal and F2017 Status Quo (%)	Bill Impact (%) of F2017 BC Hydro Proposal (vs. F2016 Rates)
Min	1	86	117	31	36	42
10	2,001	309	337	28	9	13
20	4,773	618	642	24	4	8
30	7,797	956	975	19	2	6
40	11,184	1,334	1,348	14	1	5
50	15,288	1,792	1,800	8	0	4
60	20,648	2,390	2,390	0	0	4
70	28,435	3,259	3,247	-12	0	4
80	40,838	4,643	4,613	-30	-1	3
90	65,174	7,359	7,292	-67	-1	3
Max	615,810	68,810	67,918	-892	-1	3

Table 6-3A illustrates the distribution of bill impacts of the single account at each specified consumption percentile and not the impact of a group of accounts in blocks of 10 per cent. Thus, the result for the 10th percentile shows the bill for the single account that represents the 10th percentile of consumption of accounts in the sample used for the analysis. The forecasted number of SGS accounts, which the distribution in Table 6-3 applies to, are as follows in the table below.

Forecast Year	Forecast Number of Accounts	10% of Forecast Number of Accounts
F2017	181,698	18,170
F2018	183,727	18,373
F2019	185,817	18,582

Thus, in F2017, 18,170 customers are forecast to be in the lowest 10 per cent group of customers.

BC Hydro is not proposing any measure to minimize bill impacts to SGS customers resulting from the increase in the SGS basic charge. As stated in Chapter 6 of the Application, in BC Hydro's view there are no rate design objectives to be traded off under its SGS proposal.

Increasing the SGS basic charge recovery to 45 per cent of customer-related costs aligns with the Bonbright fairness criterion by matching embedded cost recovery in rates with cost causation. Moreover, there is no conflict with the economic efficiency criterion. The bill impacts of the proposed basic charge cost recovery increase are minimal to the majority of SGS customers on both a percentage and absolute basis. That is, 90 per cent SGS customers have bill differences below 10 per cent, and the bill difference is below 5 per cent for 80 per cent of SGS customers.

56.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.3.2.1, 6.3.3.2 & Appendix C-4A Medium General Service, pp. 6-17, 6-22 & C-4A, pp. 8 and 9
Medium General Service Conservation

BC Hydro states on page 6-17: "The two-part energy rate structure was approved for the MGS class under the terms of the NSA. The overarching objective of the two-part rate structure was to provide MGS customers with an efficient price signal to induce energy conservation." Slides from Workshop 8A and 8B identify that the development of the baseline rates for LGS and MGS was a result of Direction 19 of the 2007 RDA directing the development of a LGS rate that encouraged conservation while not harming or benefiting customers unduly.

Page 6-22 states that

The evaluation of these multiple lines of evidence indicated that the customer response to the MGS two-part energy rate was considerably less than forecast. Awareness and demonstrated understanding of the MGS rates was low. Evaluated net energy savings for MGS rate were not statistically different than zero in 2011, 2012 and F2014, relative to calendar year 2010, as compared to a forecast conservation savings of about 140 GWh/year.

1.56.1 Does BC Hydro consider that the twin-goal to achieve both conservation and not harming or benefiting customers is inherently incompatible?

RESPONSE:

BCUC staff asked BC Hydro this question in their written feedback concerning Workshops 8a/8b, and BC Hydro responded through its Workshop 8a/8b consideration memo as follows:

- **"BC Hydro concludes that the 2007 RDA directive 19 objective of encouraging conservation without unduly harming or benefitting customers has proven to be incompatible for the diverse MGS customer group" (Exhibit B-1, Appendix C-4A, page 185 of 813);**

- **"In response to BCUC staff's question concerning 2007 RDA Decision Directive 19, it is less clear to BC Hydro that encouraging conservation without unduly harming or benefitting customers has proven to be incompatible for the LGS customer group. BC Hydro acknowledges the trade-offs between economic efficiency and customer understanding and acceptance (bill impacts, simplicity) …" (Exhibit B-1, Appendix C-4A, page 193 of 813).**

56.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.3.2.1, 6.3.3.2 & Appendix C-4A Medium General Service, pp. 6-17, 6-22 & C-4 A, pp. 8 and 9 Medium General Service Conservation

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1.56.1.1 Is it fair to conclude that BC Hydro has determined that there is no conservation rate alternative that would be fair to the diverse customer base of the MGS class? Please discuss. In the discussion, please comment whether the conservation shortfall is the result of rate complexity, customer heterogeneity, and low elasticity of demand to rate signals, e.g., factors such as tax deductibility of electricity charges for commercial customers or the relatively low cost of electricity as a business cost to MGS customers as reflected in the low elasticity?

RESPONSE:

BC Hydro believes that there are probably multiple contributing factors that led to the existing MGS rate being ineffective. One factor was the complexity of the design, which led to a lack of customer awareness and understanding. Part of the reason that the rate was complex was that it was designed to cover a diverse class.

BC Hydro has not determined that "there is no conservation rate alternative that would be fair to the diverse customer base of the MGS class," but BC Hydro has not identified a viable alternative at this time. Moreover, BC Hydro has ruled out the following two conservation rate options for the MGS class:

- **Inclining Block Rate – BC Hydro, with input from E3, determined that an inclining block rate would not be viable given that it would be difficult to set a fair and**

reasonable threshold between Tier 1 and Tier 2 pricing for the heterogeneous MGS rate class; and

- **Baseline Rate - BC Hydro is of the view that the complexity of the MGS two-part rates has been a large barrier to conservation, as highlighted by the results of its evaluation, summarized on pages 6-22 to 6-23 of Exhibit B-1. Awareness and demonstrated understanding of the MGS rates was low.**

As discussed on page 31 of the Workshop 11a/11b Consideration Memo at Appendix C-4B of Exhibit B-1 (page 181 of 382), BC Hydro has not heard from customers or internally that tax deductibility reduces interest in DSM. BC Hydro has not estimated the impact of tax deductibility on customer price elasticity. This would require a level of precision that BC Hydro does not have concerning behavioural response to prices. Given the immediate effect of prices on customer response versus the lagged effect of taxes, the effect of tax deductibility on price elasticity could be minimal.

57.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.2 Medium General Service, pp. 6-19 and 6-34;
Section 6.4.5 Large General Service Rate Structure, pp. 6-55 to 6-56
Medium and Large General Service demand charges

BC Hydro states on page 6-19: "Most jurisdictions have flat or declining demand charges. The key issue associated with the existing MGS three-step inclining block demand charge is that it does not align with BC Hydro's cost to serve MGS customer peak demand, which is generally flat on a $/kW basis."

AMPC commented at Workshop 8b that a flat demand charge would better reflect cost causation.

1.57.1 Please provide the reference to the COSS demonstrating the demand cost causality being generally flat on a $/KW basis?

RESPONSE:

Figure 4-2 on page 4-12 of Exhibit B-1 shows that the cost in $/kW for customers under 150 kW is generally flat though with a slight decline of $0.24/kW from the smallest to the largest segments in the MGS class.

57.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.2 Medium General Service, pp. 6-19 and 6-34;
Section 6.4.5 Large General Service Rate Structure, pp. 6-55 to 6-56
Medium and Large General Service demand charges

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AMPC commented at Workshop 8b that a flat demand charge would better reflect cost causation.

1.57.2 Is this true for all classes of customers?

RESPONSE:

BC Hydro has completed this analysis on the General Service rate classes only, to which the same conclusion applies.

57.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.2 Medium General Service, pp. 6-19 and 6-34;
Section 6.4.5 Large General Service Rate Structure, pp. 6-55 to 6-56
Medium and Large General Service demand charges

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AMPC commented at Workshop 8b that a flat demand charge would better reflect cost causation.

1.57.3 Please explain why BC Hydro no longer proposes a first Tier demand charge (i.e, 35 kW at zero cost) for MGS and LGS customers. Please comment if retaining this first Tier would smooth customers' transition between SGS and MGS rates.

RESPONSE:

Generally speaking, the single flat demand charge will improve fairness between customers; a single demand charge is better aligned with the cost to serve a General Service customer's peak demand, which is flat on a $/kW basis, as referred to in the preamble above. A flat demand charge also simplifies the rate structure, which will improve customer understanding and acceptance relative to the existing inclining block demand charge structure.

For MGS, further support for a flat demand charge relates to the fact that the existing demand charge structure does not substantially differ from an alternative two-step demand charge (with the first block of 35 kW at zero cost) in terms of fairness and bill impact considerations – please refer to pages 6-29 to 6-30 of Exhibit B-1 for further discussion.

For LGS, further support for a flat demand charge stems from the effect of the structure in offsetting the bill impacts of BC Hydro's proposal to flatten LGS energy rates - please refer to pages 6-56 and 6-62 of Exhibit B-1 for further discussion.

There was a general consensus among stakeholders that MGS and LGS flat demand charges are superior to the existing MGS and LGS demand charge and the alternative MGS and LGS two-step inclining block demand charge structures.

Retaining the first tier of demand (35 kW) at zero cost will not necessarily smooth the bill impact of any customer transitioning between SGS and MGS rates under BC Hydro's SGS and MGS proposals. The table below compares the difference in a customer's F2017 bill from a move between SGS and MGS rates at the seam, under four examples. Under BC Hydro's proposals, the last column in the table, an SGS customer would see a lower bill from a move to MGS rates at the seam, unless the customer had a very low load under which utilization would be too low for lower MGS energy charges to offset the charges for the first 35 kW of demand.

	F2017 Percentage Change in Customer Bill moving from SGS to MGS Rates at the Seam (%)			
Load Factor	**SGS Status Quo to MGS Status Quo**	**SGS Proposal to MGS Status Quo**	**SGS Status Quo to MGS Proposal**	**SGS Proposal to MGS Proposal**
20	**-7.7**	**-6.8**	**5.7**	**6.6**
30	**-7.7**	**-6.7**	**-4.0**	**-3.0**
40	**-7.7**	**-6.7**	**-8.8**	**-7.8**
50	**-7.7**	**-6.6**	**-11.7**	**-10.7**
60	**-7.7**	**-6.6**	**-13.7**	**-12.6**

58.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.3.2 Medium General Service, p. 6-22, Footnote 237
Medium General Service demand charges

"The MGS forecasted conservation savings were based on the overall commercial customer price elasticity of -0.1 (consisting of rate structure induced conservation and natural conservation) based on the jurisdictional assessment set out in Appendix E to the BC Hydro's 2008 Long-Term Acquisition Plan, with adjustments."

1.58.1 On page 6-22, BC Hydro states that "evaluated net energy savings for MGS rate were not statistically different than zero in 2011, 2012 and F2014, relative to calendar year 2010, as compared to a forecast conservation savings of about 140 GWh/ year." What level of DSM conservation is expected from the proposed new MGS rate structure and what levels of price elasticity are now assumed for each of the general service classes?

RESPONSE:

As set out in BC Hydro's response to BCUC IR 1.7.1:

- **Natural conservation is conservation induced by general rate increases applied to rate classes through RRAs, absent any rate structure changes, and is not considered by BC Hydro to be DSM; and**

- **Rate structure conservation is the incremental conservation induced by changing the elements of the rate structure, and is considered by BC Hydro to be DSM.**

BC Hydro is not forecasting any rate structure conservation from either the existing MGS rate structure (please refer to BC Hydro's response to BCUC IR 1.8.1) or the proposed MGS rate structure. BC Hydro is forecasting natural conservation from the proposed MGS rate structure using an elasticity of -0.05, which as noted at Exhibit B-1, page 5-17, lines 12-14, is the class average price elasticity assumption used to determine the natural conservation baseline.

59.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.4.2 MGS Screening of Alternatives and Stakeholders Engagement, pp. 6-28 and 6-29 Methodology to estimate energy and peak demand savings

On page 6-28, BC Hydro says: "…. AMPC stated that the inability to annually adjust baselines to reflect changes in use is a significant problem for a heterogeneous class, and thus a flat energy rate may be more useful in providing a conservation price signal than a tiered energy rate."

1.59.1 In BC Hydro's view, does the above concern hold only for a heterogeneous general service rate class? For example, does the statement also apply to customers taking service at transmission voltage or to Residential customers? Please explain.

RESPONSE:

In BC Hydro's view it is not the heterogeneous nature of MGS and LGS rate classes that makes annually adjusted baselines not feasible; rather it is the large number of customer accounts in each rate class (over 23,000 accounts); refer to Figure 6-2 of Exhibit B-1.

As described in section 2.3 of the Workshop 3 Consideration memo found at Appendix C3-A of Exhibit B-1, BC Hydro explored the viability of a customer specific baseline rate for the Residential class and found it not to be a viable option for the approximately 1.8 million residential customers.

BC Hydro notes that for there are approximately 140 Transmission Service customers taking service under RS 1823. The relatively small number of such customers makes annually adjusted baselines practical to administer.

59.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.4.2 MGS Screening of Alternatives and Stakeholders Engagement, pp. 6-28 and 6-29 Methodology to estimate energy and peak demand savings

On page 6-28, BC Hydro says: "…. AMPC stated that the inability to annually adjust baselines to reflect changes in use is a significant problem for a heterogeneous class, and thus a flat energy rate may be more useful in providing a conservation price signal than a tiered energy rate."

1.59.2 Please elaborate on how a flat energy rate may be more useful in providing a conservation price signal than a tiered energy rate. For example, should the flat energy charge be always set within the LRMC range? Should basic charge and demand charge be lowered in order to allow a higher energy charge within the constraints of revenue neutrality in rate design?

RESPONSE:

AMPC's statement could be understood to mean that a tiered energy rate may be economically efficient in theory, but if it is too complex to be understood and acted upon it may not be as useful in providing a conservation price signal as compared to a flat rate that also provided an efficient price signal, even if providing only a price signal for natural, not rate structure, conservation.

Questions such as whether a flat rate should always be set within a LRMC range or whether basic and demand charges should be lowered to maintain a higher energy charge cannot be answered in the absolute. Rather, such questions raise fundamental trade-offs between rate design objectives, such as fairness, economic efficiency and customer understanding and acceptance. Given BC Hydro's current priorities as discussed in section 1.5 of Exhibit B-1, and for the reasons set out in section 6.3 of Exhibit B-1 and section 6.3.5 in particular, BC Hydro considers that its MGS energy rate and demand charge proposals strike an appropriate balance between these objectives given the current issues with MGS rates.

59.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.4.2 MGS Screening of Alternatives and Stakeholders Engagement, pp. 6-28 and 6-29 Methodology to estimate energy and peak demand savings

The Application states on page 6-29 that "15 of the 22 feedback forms submitted by attendees favoured the MS-5 MGS flat energy rate alternative with many emphasizing DSM programs as the better vehicle for conservation; three preferred the MS-2 flatten the energy charges but retain the baseline alternative; and two favoured the existing MGS rate."

1.59.3 Please provide in your response the following data related to MGS customer annual consumption profile:

a. Percentage of MGS customers consuming energy for 12 consecutive months in Part 1 only.
b. Percentage of MGS customers consuming energy for 12 consecutive months at Part 1 and Part 2 rates.
c. Percentage of Part 1 only MGS customers consuming at Tier 2 only for at least 12 consecutive months.
d. Percentage of Part 1 only MGS customers consuming at both Tier 1 and Tier 2 for at least 12 consecutive months.
e. Percentage of MGS customers who trigger the Price Limit Band provision.

RESPONSE:

a. Consuming only at the Part 1 rate means consuming exactly at baseline. There was no MGS customer consuming energy only at the Part 1 rate for 12 consecutive months.

Among all MGS accounts that had at least 12 months consumption history past the 85/15 new account pricing period, 33 per cent had usage below Part 1 consumption (received Part 2 credits) for 12 consecutive months.

b. Among all MGS accounts that had at least 12 months consumption history past the 85/15 new account pricing period, almost 100 per cent was billed under both Part 1 and Par 2 rates (received either Part 2 credits or charges) for 12 consecutive months.

Among all MGS accounts that had at least 12 months consumption history past the 85/15 new account pricing period, 17 per cent had usage above Part 1 consumption (received Part 2 charges) for 12 consecutive months.

c. There was no MGS account consuming only at the Part 1 rate for 12 consecutive months, and it is impossible to only consume at Part 1 Tier 2 rate as Tier 1 rate applies before Tier 2 rate. However, 8 per cent of MGS accounts consumed below Part 1 consumption and only at Tier 1 rate for 12 consecutive months.

d. There was no MGS account consuming only at the Part 1 rate for 12 consecutive months. However, 10 per cent of MGS accounts consumed below Part 1 consumption and at both Tier 1 and Tier 2 rates for 12 consecutive months.

e. 5 per cent of MGS accounts had triggered the price limit band.

60.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.4.2 Medium General Service, pp. 6-30 and 6-32
Medium General Service demand charges

BC Hydro reviewed two demand charge related items in the workshop. One item is as follows:

An increase in demand charge recovery of demand-related costs from 15 per cent to 35 per cent. The 35 per cent cost recovery level was arrived at by targeting an increase that would result in a flat energy rate that remained generally reflective of the energy LRMC, thereby balancing the competing Bonbright economic efficiency criterion. There is no single 'correct' level of demand charge cost recovery and demand charge cost recovery cannot be targeted in isolation from other factors. The effect of an increase to 35 per cent cost recovery is to more evenly offset and distribute the bill impacts of BC Hydro's preferred MGS flat energy rate and MGS flat demand charge among customers with differing load factors and consumption levels.

On page 6-32, the Application comments that "BC Hydro acknowledged that as a result of the proposed increase to the demand charge, the MGS flat energy rate under its proposal drops below the lower bound of the energy LRMC range (F2017: MGS flat energy rate is 8.54 cents/kWh and the lower end of the energy LRMC range is 9.46 cents/kWh)."

In its Workshop 11a/11b consideration memo, BC Hydro adopted the perspective of AMPC that the energy LRMC should not be relied on with a "false precision." BC Hydro regards the MGS flat energy rate under its proposed demand charge cost recovery increase to be reflective of the energy LRMC.

1.60.1 Would it not have been preferable to have proposed a demand cost recovery percentage that would have kept the flat energy rate closer to LRMC? Please discuss the trade off between customer bill impacts and LRMC price signals.

RESPONSE:

This question raises the issue of false precision in rate design generally and in particular with respect setting an energy charge that equals LMRC. Absent a specific criteria for what a single 'correct' level of demand charge cost recovery ought to be in isolation of other factors, BC Hydro's initial estimation of an increase in demand-related cost recovery was based on targeting a flat energy rate equal to the lower end of the LRMC range. With subsequent updates to the forecast inputs to rate determinations, the MGS flat energy rate is no longer

precisely equal to the lower bound of the range in BC Hydro's energy LRMC, although still generally reflective of it. BC Hydro does not agree that the Bonbright efficiency criterion should always trump the remaining seven Bonbright criteria, including the Bonbright fairness and customer understanding criteria. BC Hydro also raises the Bonbright rates stability criterion of continually adjusting rates to ensure energy rates equal the energy LMRC.

60.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.4.2 Medium General Service, pp. 6-30 and 6-32
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In its Workshop 11a/11b consideration memo, BC Hydro adopted the perspective of AMPC that the energy LRMC should not be relied on with a "false precision." BC Hydro regards the MGS flat energy rate under its proposed demand charge cost recovery increase to be reflective of the energy LRMC.

1.60.2 What would the energy rate be in Table 6-9 if the flat demand cost recovery were set at 20 percent, 25 percent or 30 percent?

RESPONSE:

The F2017 illustrative MGS flat demand and flat energy rates given demand cost recovery of 20 per cent, 25 per cent, and 30 per cent are as follows:

	MGS Flat Demand Cost Recovery Percent		
	20%	**25%**	**30%**
Energy Rate (cents/kWh)	**9.17**	**8.96**	**8.75**
Demand Charge ($/kW)	**2.72**	**3.40**	**4.08**
Basic Charge (cents/day)	**23.47**	**23.47**	**23.47**

60.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.4.2 Medium General Service, pp. 6-30 and 6-32
Medium General Service demand charges

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In its Workshop 11a/11b consideration memo, BC Hydro adopted the perspective of AMPC that the energy LRMC should not be relied on with a "false precision." BC Hydro regards the MGS flat energy rate under its proposed demand charge cost recovery increase to be reflective of the energy LRMC.

1.60.3 Under the conservative rate structure, the Step 2 or upper Tier rate was designed to have the energy LRMC as referent. In BC Hydro's view, is it still necessary for a flat rate (as proposed for the MGS rate class) to be reflective of the LRMC given that some MGS customers may always be consuming at the current Part 1 level of the 2-part rate?

RESPONSE:

No, it is not necessary for a flat rate as proposed for the MGS rate class to be reflective of LRMC; in this regard please refer to BC Hydro's response to BCUC IR 1.60.1.

60.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.4.2 Medium General Service, pp. 6-30 and 6-32
Medium General Service demand charges

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On page 6-32, the Application comments that "BC Hydro acknowledged that as a result of the proposed increase to the demand charge, the MGS flat energy rate under its proposal drops below the lower bound of the energy LRMC range (F2017: MGS flat energy rate is 8.54 cents/kWh and the lower end of the energy LRMC range is 9.46 cents/kWh)."

In its Workshop 11a/11b consideration memo, BC Hydro adopted the perspective of AMPC that the energy LRMC should not be relied on with a "false precision." BC Hydro regards the MGS flat energy rate under its proposed demand charge cost recovery increase to be reflective of the energy LRMC.

1.60.4 When the upper Tier of a two-Tier rate structure exceeds the LRMC, it may be considered that the pricing is not economically efficient. Does the false precision perspective, advanced by AMPC and adopted by BC Hydro, apply to proposed rates above the LRMC range, i.e., concluding rates are economically inefficient when rates are above LRMC?

RESPONSE:

As discussed in BC Hydro's response to BCUC IR 1.41.2, economic efficiency does not require that prices be equal to LRMC. Prices that exceed LRMC are not automatically economically inefficient. Economic efficiency is a largely relative criterion – prices are considered more economically efficient the closer they are to actual LRMC.

60.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.4.2 Medium General Service, pp. 6-30 and 6-32
Medium General Service demand charges

BC Hydro reviewed two demand charge related items in the workshop. One item is as follows:

An increase in demand charge recovery of demand-related costs from 15 per cent to 35 per cent. The 35 per cent cost recovery level was arrived at by targeting an increase that would result in a flat energy rate that remained generally reflective of the energy LRMC, thereby balancing the competing Bonbright economic efficiency criterion. There is no single 'correct' level of demand charge cost recovery and demand charge cost recovery cannot be targeted in isolation from other factors. The effect of an increase to 35 per cent cost recovery is to more evenly offset and distribute the bill impacts of BC Hydro's preferred MGS flat energy rate and MGS flat demand charge among customers with differing load factors and consumption levels.

On page 6-32, the Application comments that "BC Hydro acknowledged that as a result of the proposed increase to the demand charge, the MGS flat energy rate under its proposal drops below the lower bound of the energy LRMC range (F2017: MGS flat energy rate is 8.54 cents/kWh and the lower end of the energy LRMC range is 9.46 cents/kWh)."

In its Workshop 11a/11b consideration memo, BC Hydro adopted the perspective of AMPC that the energy LRMC should not be relied on with a "false precision." BC Hydro regards the MGS flat energy rate under its proposed demand charge cost recovery increase to be reflective of the energy LRMC.

1.60.5 Please confirm that the introduction of LRMC as a range in the 2015 RDA is an admission that the LRMC is not a precise number.

RESPONSE:

Confirmed.

In periods when BC Hydro had energy supply needs that exceeded DSM and IPP renewals, the LRMC for energy was based upon the energy costs of greenfield clean or renewable IPP resources. In these circumstances, the LRMC was estimated based upon either the last open clean call (e.g., the F2006 Open Call for Tenders, the 2009 Clean Power Call) or the best estimate of the cost of new resources through BC Hydro's Resource Options Report (e.g., Chapter 3 of the

2013 IRP). The LRMC developed at that time was an estimate of the cost of a new open clean call and could vary.

Currently, the LRMC is estimated as the price signal at which BC Hydro would acquire sufficient energy to meet its plans and system needs. However, neither the marginal cost of the next unit of DSM savings consistent with energy policy and broad customer participation nor the precise cost of IPP EPA renewals are clearly known. As such, a range was developed to represent this uncertainty.

61.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.5 BC Hydro Proposal and Stakeholders Engagement, p. 6-33
Illustrative simulation

On page 6-33, BC Hydro describes that all alternatives recover the same target revenue of $371 million given a consumption forecast of 3,517 GWh and 10.9 GW of billed demand.

1.61.1 The 3,517 GWh consumption forecast is modelled to the status quo MGS rate. Has BC Hydro also modelled forecasts on the energy consumption by MGS customers on the assumption that its proposed default MGS rate design is approved for F17, F18 and F19? If so, please describe the difference in consumption forecast as a result of substantially different price signals.

RESPONSE:

BC Hydro has not modelled consumption forecasts separately under the existing MGS rate and the proposed default MGS flat rate:

- **The forecasted rate-structure induced conservation for the existing MGS rate is zero kWh for F2017, F2018, and F2019. The F2014 LGS and MGS Evaluation Report and the 2011-2012 LGS and MGS Evaluation Report indicated no statistically significant rate structure induced conservation attributable to marginal price response on the existing MGS rate; and**

- **BC Hydro has no further information on the MGS rate class to construct further conservation models, given the evaluation outcomes. BC Hydro also has no evidence to suggest that a flat MGS rate will substantially change consumption behaviour as compared to the existing MGS rate.**

61.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.5 BC Hydro Proposal and Stakeholders Engagement, p. 6-33
Illustrative simulation

On page 6-33, BC Hydro describes that all alternatives recover the same target revenue of $371 million given a consumption forecast of 3,517 GWh and 10.9 GW of billed demand.

1.61.2 In BC Hydro's view, should its stakeholders and the Commission be concerned with increased energy consumption as a result of the MGS rate design changes? Has BC Hydro addressed the conservation savings target that is part of the provincial government's energy objectives? If not, please explain why not.

RESPONSE:

BC Hydro is not relying on energy savings from the existing MGS rate to achieve the *CEA* section 2(b) British Columbia's energy objective of BC Hydro reducing its expected increase in demand for electricity by the year 2020 by at least 66 per cent. This is because BC Hydro is forecasting zero energy savings from the existing MGS rate. Please refer to BC Hydro's response to BCUC IR 1.8.1.

Additionally, it is not clear there will be increased energy consumption under the MGS flat rate proposal given it is priced just below LRMC and the natural conservation elasticity assumption is low at -0.05.

62.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.5 BC Hydro Proposal and Stakeholders Engagement, p. 6-36, Figure 6-6 Bill impact under the demand charge 35 percent Recovery

Figure 6-6 shows that customers experiencing the highest bill impact are characterized by low consumption and low load factor, with impacts mostly triggered by having demand charges for all kW.

1.62.1 Has BC Hydro conducted an analysis of the likelihood of those MGS customers who are unfavourably impacted as candidates for migration to the SGS rate class? Please describe the analysis.

RESPONSE:

The billing data shows that 475 MGS accounts as of March 2014 have migrated to SGS by March 2015. Of those accounts, 16 have characteristics that are consistent with high bill impacts as illustrated in Exhibit B-1, Figure 6-6; namely annual consumption less than or equal to 60,000 kWh and an annual load factor less than or equal to 20 per cent.

62.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.5 BC Hydro Proposal and Stakeholders Engagement, p. 6-36, Figure 6-6 Bill impact under the demand charge 35 percent Recovery

Figure 6-6 shows that customers experiencing the highest bill impact are characterized by low consumption and low load factor, with impacts mostly triggered by having demand charges for all kW.

1.62.2 In the past three years, what were the migration patterns between SGS and MGS? What were the bill impacts under the status quo tariffs for those who migrated?

RESPONSE:

Please refer to the table below for all migrations among General Service rates from April 1, 2013, the date by which all MGS accounts were transferred to the existing two-part MGS rate.

All migrated accounts had unique consumption pattern and the migration was triggered by multiple billing periods over a period of 12 months. Bill impacts of the rate migration cannot be accurately calculated. For a high level analysis, BC Hydro pulled the energy (kWh) and peak demand (kW) of each migrated account at the point of migration, applied the F2016 before and after migration rates and calculated the difference of the sum of energy and demand charges. For energy charge, only Part 1 rates were applied. Part 2 energy charges or credits were not included in the analysis. Accounts with unusual consumption history, e.g., demand ratchet applied, were also excluded from the analysis.

Group	Number of Accounts	Estimated Average Bill Impact (Energy and Demand Charges) ($)
LGS to MGS	345	18
LGS to SGS	79	-22
MGS to LGS	612	-745
MGS to SGS	2,303	83
SGS to LGS	14	-1,951
SGS to MGS	2,184	-210

62.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.5 BC Hydro Proposal and Stakeholders Engagement, p. 6-36, Figure 6-6
Bill impact under the demand charge 35 percent Recovery

BC Hydro shows the bill impacts at both a 35 percent demand cost recovery and at 15 percent.

1.62.3 Would it be the case that more than 90 percent of customers would have a bill impact less than 10 percent under any of the demand cost recovery proposals between the existing 15 percent and the proposed 35 percent?

RESPONSE:

Yes, in the context of a rate change in F2017.

63.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.5.2 MGS Demand Sensitivity Rate Structure (15 Per Cent Recovery), pp. 6-37, 6-57
Bill impact analysis

On pages 6-37 and 6-56, BC Hydro describes AMPC's belief that high load factor customers make more efficient use of BC Hydro's system and, therefore, the demand sensitivity outcome is not acceptable.

1.63.1 In BC Hydro's view, is intra-rate class cross subsidy an issue in rate design? Is undue discrimination more specifically applied to inter-class bill impact?

RESPONSE:

In BC Hydro's view:

- **The Bonbright fair apportionment of costs among customers criterion applies to both inter-rate class and intra-rate class (refer to Table 2-7 of Exhibit B-1); and**

- **Undue discrimination applies to both inter-rate class and intra-rate class. For example, the AUC concluded that in the absence of express language authorizing it to set rates according to a residential customer's ability to pay rather than according to the cost of serving those customers, low income rates are unduly preferential and/or unjustly discriminatory (AUC, Decision 2004-066, section 9.2.6; refer to page 5-58 of Exhibit B-1). The AUC was applying the undue discrimination test to an intra-rate class situation as low income residential customers are part of the residential rate class.**

63.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.3.5.2 MGS Demand Sensitivity Rate Structure (15 Per Cent Recovery), pp. 6-37, 6-57
Bill impact analysis

On pages 6-37 and 6-56, BC Hydro describes AMPC's belief that high load factor customers make more efficient use of BC Hydro's system and, therefore, the demand sensitivity outcome is not acceptable.

1.63.2 In making the choice between 35 percent demand recovery and 15 percent demand recovery, what priority or weight should be given to issues related to rate stability (e.g., paying for the first 35 kW which used to be free), price signal (e.g., energy rate below LRMC range) and intra-class cross subsidy? Please explain.

RESPONSE:

BC Hydro's decision to propose an increase in the demand charge to recover 35 per cent of demand-related costs reflects prioritization of the Bonbright fairness and customer understanding criteria:

- **Fairness – improve alignment of embedded cost recovery in rates with cost causation. Increasing the level of demand charge cost recovery more fairly matches the recovery of the cost to serve a customer's peak demand with the customer's utilization of the system, but within limits based on avoiding excessive bill impacts (for example, such as associated with 100 per cent demand charge cost recovery); and**

- **Customer Understanding – BC Hydro's proposal leads to a general offsetting in the bill impacts of its energy and demand rate structure proposals, and in particular with respect to customers with high utilization and load factor.**

64.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.4.2 Existing LGS Energy Rate, p. 6-40
LGS customer profile

Table 6-14 sets out the existing LGS Energy Rate for F2016.

1.64.1 Please provide the following data related to LGS customer annual consumption profile:

a. Percentage of LGS customers consuming energy for 12 consecutive months in Part 1 only.
b. Percentage of LGS customers consuming energy for 12 consecutive months at Part 1 and Part 2 rates.
c. Percentage of Part 1 only LGS customers consuming at Tier 1 only for at least 12 consecutive months.
d. Percentage of Part 1 only LGS customers consuming at both Tier 1 and Tier 2 for at least 12 consecutive months.
e. Percentage of LGS customers who trigger the Price Limit Band provision.

RESPONSE:

a. Consuming only at the Part 1 rate means consuming exactly at baseline. There was no LGS customer consuming energy only at the Part 1 rate for 12 consecutive months.

Among all LGS accounts that had at least 12 months consumption history past the 85/15 new account pricing period, 54 per cent had usage below Part 1 consumption (received Part 2 credits) for 12 consecutive months. The higher percentage is likely due to the high initial baselines selected between two different periods during the LGS rate implementation.

b. Among all LGS accounts that had at least 12 months consumption history past the 85/15 new account pricing period, almost 100 per cent was billed under both Part 1 and Par 2 rates (received either Part 2 credits or charges) for 12 consecutive months.

Among all LGS accounts that had at least 12 months consumption history past the 85/15 new account pricing period, 25 per cent had usage above Part 1 consumption (received Part 2 charges) for 12 consecutive months.

c. There was no LGS account consuming only at the Part 1 rate for 12 consecutive months. However, 1 per cent of LGS accounts consumed

below Part 1 consumption and only at Tier 1 rate for 12 consecutive months.

d. There was no LGS account consuming only at the Part 1 rate for 12 consecutive months. However, 45 per cent of LGS accounts consumed below Part 1 consumption and at both Tier 1 and Tier 2 rates for 12 consecutive months.

e. 67 per cent of LGS accounts had triggered the price limit band.

65.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.4.2.1 Existing LGS Energy Rate, p. 6-42
New accounts pricing (85/15 Pricing Rule)

The mechanism of LGS rate structure include a provision for new accounts where the last 15 percent of energy consumed in a monthly billing period will be charged at the Part 2 energy rate rather than at the Part 1 energy rate until a baseline level of consumption is established one year hence.

1.65.1 Since the implementation of the LGS rate, how many new accounts have used 85/15 pricing? Please compare this group to the percentage of LGS customer who consume only at Part 1 rate for at least 12 consecutive months.

RESPONSE:

From January 2011 to September 2015, there were 2,427 new LGS accounts billed under 85/15 pricing, which is 27 per cent of total LGS accounts.

There was no LGS account consuming only at the Part 1 rate for 12 consecutive months.

65.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.4.2.1 Existing LGS Energy Rate, p. 6-42
New accounts pricing (85/15 Pricing Rule)

The mechanism of LGS rate structure include a provision for new accounts where the last 15 percent of energy consumed in a monthly billing period will be charged at the Part 2 energy rate rather than at the Part 1 energy rate until a baseline level of consumption is established one year hence.

1.65.2 Does the 85/15 pricing also apply to MGS customers? If so, please provide the information as in the question above.

RESPONSE:

From April 2012 to September 2015, there were 5,153 new MGS accounts billed under 85/15 pricing, which is 25 per cent of total MGS accounts.

There was no MGS account consuming only at the Part 1 rate for 12 consecutive months.

65.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.4.2.1 Existing LGS Energy Rate, p. 6-42
New accounts pricing (85/15 Pricing Rule)

The mechanism of LGS rate structure include a provision for new accounts where the last 15 percent of energy consumed in a monthly billing period will be charged at the Part 2 energy rate rather than at the Part 1 energy rate until a baseline level of consumption is established one year hence.

1.65.3 Does the 85/15 pricing also apply to incremental load under Tariff Supplement (TS) 82? If so, please provide the frequency that TS 82 has been applied since its implementation.

RESPONSE:

Yes, the 85/15 pricing applies to the incremental load under TS 82 for the first 12 months.

Twenty customers have been under TS 82. Among those 20, four customers dropped off after year one because they did not meet the consumption growth threshold.

66.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.2 & 6.4.3 Large General Service, pp. 6-43 to 6-49
Large General Service Conservation

On page 6-43, BC Hydro states "…the key issue with the existing LGS two-part energy rate is that it does not provide a clear price signal for conservation and is poorly understood by customers. The result is that minimal conservation savings have been delivered to date, and that BC Hydro cannot count on and does not forecast any conservation savings going forward."

On page 6-46, BC Hydro states "The LGS two-part energy rate has been evaluated through the 2011-2012 LGS and MGS Evaluation Report and F2014 LGS and MGS Evaluation Report to have delivered lower than expected conservation savings with a declining confidence in the persistence of the savings…"

On page 6-48, BC Hydro states "LGS customers may have greater, longer lasting responses if they understand the details of the rate well enough to quantify the benefits they may receive by responding."

On page 6-49, BC Hydro states:

The reason for carrying forward the SQ LGS Simplified Energy Rate is that in contrast to the MGS rate: the LGS energy rate has resulted in some energy conservation; some LGS customers desire to retain the baseline-based rate structure; and as described below, the LGS flat energy rate is not reflective of the energy LRMC range, so simplification does in this case have some trade-off with losses in efficiency and conservation.

1.66.1 Since the current LGS rate structure has delivered some energy savings, what initiatives could BC Hydro undertake to improve customer understanding of the rate features and see if that results in improved future savings? Should these educational initiatives be undertaken now and the existing rate re-evaluated in the next RDA?

RESPONSE:

As stated in the Workshop 8a/8b consideration memo, Exhibit B-1, Appendix C-4A page 225 of 813, BC Hydro made efforts in customer communications and education during the implementation of LGS and MGS rates, and developed online tools, videos and detailed rate guides to help customers understand the rates. Many face-to-face customer meetings have also occurred in the past five years. In some cases, LGS customers still did not fully understand the rate after one-on-one in-person meetings.

While BC Hydro could undertake additional communications or education activities at the mass market level, due to the complexity of the rate it is unclear whether this would improve understanding of the LGS baseline rate or that such additional communication/education activities would lead to the delivery of conservation. Accordingly BC Hydro is opposed to deferring consideration of its LGS flat rate proposal to an undetermined time corresponding with its next RDA which is likely to be no sooner than five years from now.

66.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.2 & 6.4.3 Large General Service, pp. 6-43 to 6-49
Large General Service Conservation

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The reason for carrying forward the SQ LGS Simplified Energy Rate is that in contrast to the MGS rate: the LGS energy rate has resulted in some energy conservation; some LGS customers desire to retain the baseline-based rate structure; and as described below, the LGS flat energy rate is not reflective of the energy LRMC range, so simplification does in this case have some trade-off with losses in efficiency and conservation.

1.66.2 Please explain the difference between the previous projected conservation savings (i.e., 780 GWh for F2014) and the current forecast by detailing the assumptions and methodologies used.

RESPONSE:

The rate structure conservation forecast of 780 GWh/year for F2014 was forecasted using the methodologies consistent with Appendix P of the 2009 LGS Application. The central assumptions for this method are as follows:

1. **Most customers are exposed to the Part-2 LRMC as their marginal price; and**

2. **Customers are price responsive to the Part-2 LRMC component of the rate at an at assumed elasticity of about -0.10.**

While the LGS and MGS Three Year Report located in Appendix C-4A, page 589 of 813 Table 10 shows that most customers see Part-2 LRMC as their marginal price, the result of the F2014 LGS and MGS Evaluation Report as shown on Exhibit B-3, Appendix C-4A, which was summarized in Exhibit B-3, Table 6-17, concludes that the LGS rate did not result in substantial rate structure conservation on a cumulative basis at a confidence level of 90 per cent.

Given the evaluation outcome, central assumption No. 2 of the previous conservation forecast method is likely incorrect. The forecast of structural conservation for both LGS and MGS rates have been revised to zero GWh for all years going forward, consistent with the evaluation findings.

67.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.2 Large General Service, p. 6-45 Figure 6-9
Large General Service heterogeneity

1.67.1 Would BC Hydro agree that while the LGS class is heterogeneous, Figure 6-9 seems to indicate that it is less so than the MGS class? If not, please explain.

RESPONSE:

Exhibit B-1, Figure 6-9 (LGS) and Figure 6-5 (MGS) shows that both LGS and MGS classes have diverse (heterogeneous) sets of customers in terms of energy consumption. This is indicated by the different median consumption of different site types. The heterogeneity in consumption is further illustrated by the box plot on Exhibit B-1, Appendix C-4A, page 21 of 813 (LGS), and Exhibit B-1, Appendix C-4A, page 25 of 813 (MGS), which show the large spread of annual consumption for each class, respectively.

The magnitude of heterogeneity in terms of energy consumption cannot be directly compared between LGS and MGS classes, because the customers have different consumption characteristics.

67.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.2 Large General Service, p. 6-45 Figure 6-9
Large General Service heterogeneity

1.67.2 Looking at the number of customer types with medium consumption at or below 1 MW, would the diversity in the class be improved by the creation of an X-LGS class for customers over 1 MW?

RESPONSE:

The creation of an XLGS class will reduce the diversity in terms of demand (i.e., one group will be between about 150 kW and 1000 kW, while the other group will be over 1000 kW). However, demand and energy are independent metrics. As Exhibit B-1, Appendix C-4A, page 22 of 813 indicates, there is still a large range of load factors for customers at 1000 kW and beyond; therefore, high diversity in energy consumption will still likely exist in both the XLGS segment and the remaining LGS segment if the existing LGS rate class is segmented in this way as part of RDA Module 2.

68.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.3.2 Large General Service, p. 6-46
Extra Large General Service

BC Hydro states "Awareness and demonstrated understanding of the LGS rates was low. About

35 per cent of LGS customers correctly identified the two-part energy rate as applicable across four possible rate structure selections. Larger customers generally have higher unaided awareness than smaller customers."

1.68.1 Would the above statement support both the creation of an X-LGS class and the proposed shift to a flat rate for the remaining LGS customers? Why or why not?

RESPONSE:

The above reference statement should be considered only in reference to the evaluation of customer awareness and understanding of the existing LGS and MGS 2-Part energy rates. The reasons for this include:

- **The potential TSR like rate considered as part of the 2015 RDS stakeholder engagement process is similar to RS 1823, and not the existing LGS and MGS rates. The survey questions were about the existing LGS and MGS rates, not a TSR-like rate; and**

- **The F2014 LGS and MGS Evaluation Report results were not broken down by different LGS groups, so although BC Hydro knows that LGS customers had higher awareness than MGS customers, BC Hydro cannot be sure that XLGS will have higher awareness than other LGS customers.**

69.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.4.3.2 Results of Evaluation, Table 6-17, pp. 6-46 and 6-48
Cumulative net evaluated conservation savings; gigawatt hours per year

Table 6-17 summarizes the evaluated conservation savings for fiscal 2014 and calendar 2013 and calendar 2012 at different levels of statistical significance.

1.69.1 Please reconcile the discrepancy in Table 6-17 with the F2014 Evaluation Report Table 3.7 in Appendix C4 that shows 200 GWh/year savings for the end of 2012 and 144 GWh/year were for end of 2011.

RESPONSE:

The year labels are in error in Exhibit B-1, section 6.4.3.2, Table 6-17, page 6-46. The corrected table is shown below and reconciles with the F2014 LGS and MGS Evaluation Report, Table 3.7 on page 437 of 813 in Appendix C-4A.

Year	Level of Statistical Significance		
	80%	85%	90%
Fiscal 2014	77	77	0
~~Calendar 2013~~ Calendar 2012	200	200	200
~~Calendar 2012~~ Calendar 2011	144	144	144

69.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.4.3.2 Results of Evaluation, Table 6-17, pp. 6-46 and 6-48
Cumulative net evaluated conservation savings; gigawatt hours per year

On page 6-48, BC Hydro states its finding that awareness of the LGS rate was not required for a conservation response. It believes that this may offer an explanation of why LGS energy savings have diminished over time.

1.69.2 Since the savings are reportedly cumulative net savings as opposed to new savings, rather than concluding that awareness was not required for a conservation response, is it more accurate to describe that the diminished energy savings were a result of savings that were unable to persist over time?

RESPONSE:

Please refer to BC Hydro's response to BCUC IRs 1.89.1 and 1.89.2.

70.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-52
Large General Service

BC Hydro states "One customer, Loblaws, preferred the existing LS-1 energy rate, which it states provides a clear price signal to conserve electricity."

1.70.1 Would Loblaws be a large enough customer to be included in an X-LGS class?

RESPONSE:

Customers with operations akin to Loblaws would not be large enough to be included in an XLGS class if the threshold were 2 MW and eligibility was determined an individual account basis. BC Hydro's consideration of a potential XLGS rate class will be undertaken as part of RDA Module 2.

70.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-52
Large General Service

BC Hydro states "One customer, Loblaws, preferred the existing LS-1 energy rate, which it states provides a clear price signal to conserve electricity."

1.70.2 Are there lessons that could be learned from Loblaws on how to educate other LGS customers to take advantage of the existing LGS rate to conserve electricity?

RESPONSE:

In BC Hydro's view, there are not broadly applicable lessons BC Hydro could draw upon from Loblaws for purposes of educating other LGS customers as to how to take advantage of the existing LGS rate. First as noted in section 6.4.2.3 of Exhibit B-1 the LGS rate class is diverse and includes sectors that are not related to Loblaws business such as industrial light and heavy manufacturing. Second, BC Hydro's understanding is that Loblaws' situation is fairly unique in that Loblaws was already committed to investing in energy conservation across the country. The LGS rate structure provided a more attractive price incentive than available in some other service areas, therefore incenting them to focus their budgets for greater investment in conservation in B.C.

71.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-55
Large General Service flat energy rate

BC Hydro states:

LGS Flat Energy Rate - A LGS flat energy rate eliminates all complexity-related issues resulting from the baseline component of the SQ LGS Energy Rate and aligns with how other similarly situated Canadian electric utilities structure larger general service energy rates (predominantly flat). However, there is a trade-off between the customer understanding and acceptance and the economic efficiency criteria because the flat energy rate would not be reflective of LRMC (F2017: LGS flat energy rate is 5.37 cents/kWh with demand charge cost recovery at 65 per cent, and the lower end of the energy LRMC range is 9.46 cents/kWh).

1.71.1 How has BC Hydro applied its rate design objectives and priorities to weigh the LGS flat energy rate attributes of simplicity, understandability and economic efficiency to come to the conclusion that a flat energy charge is best for the LGS customers?

RESPONSE:

As described on page 6-60 of Exhibit B-1:

- **BC Hydro's proposed flat energy rate prioritizes customer understanding and acceptance by significantly simplifying the SQ LGS Energy Rate and aligning it with how other similarly situated Canadian electric utilities structure general service energy rates;**

- **BC Hydro prioritizes the Bonbright customer understanding and acceptance and fairness criteria at this time above the economic efficiency criteria as set out in sections 1.1.1, 1.5.1 and 2.4.1.2 of Exhibit B-1; and**

- **BC Hydro also notes two additional considerations: First, maintaining the status quo LGS two-part energy rates would make improving the design and cost recovery of the LGS demand charge untenable in light of the bill impacts; and second, the gains in simplification in moving to a flat energy rate appear to be worth the apparent small loss in economic efficiency in the status quo LGS rate design, as seen in the relatively small and uncertain amounts of conservation delivered by the status quo LGS two-part rate to date.**

72.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-57
Extra Large General Service rate

BC Hydro states

While BC Hydro set out considerations for a LGS TSR-Like Rate as a potential rate design for very high consumption LGS customers, it noted that its consideration of a LGS TSR-Like Rate and a segmented LGS class would be proposed only in the overall context of a LGS Flat Energy Rate applicable to the remaining majority of LGS customers. With the support of stakeholders, notably AMPC, a LGS TSR-Like Rate will be explored in RDA Module 2.

1.72.1 Why does BC Hydro limit the consideration of a TSR-like rate to the approval of a flat LGS energy charge?

RESPONSE:

BC Hydro, through its LGS energy rate proposal, is seeking to address the key issues with the existing two-part energy rate; namely, that it does not provide a clear price signal for conservation and is poorly understood by customers. Given these issues and BC Hydro's rate design priorities, BC Hydro considers it untenable to entertain any other potentially complex rate designs even for a small segment of LGS customers without first addressing the complexity-related issues of the current rates that are applicable to the entire class.

72.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-57
Extra Large General Service rate

BC Hydro states

While BC Hydro set out considerations for a LGS TSR-Like Rate as a potential rate design for very high consumption LGS customers, it noted that its consideration of a LGS TSR-Like Rate and a segmented LGS class would be proposed only in the overall context of a LGS Flat Energy Rate applicable to the remaining majority of LGS customers. With the support of stakeholders, notably AMPC, a LGS TSR-Like Rate will be explored in RDA Module 2.

1.72.2 Can BC Hydro provide further clarity on its plans for a TSR-like rate for the largest LGS customers since it may have a bearing on the acceptance of BC Hydro's proposed flat energy and flat demand charges for the remainder of the LGS class?

RESPONSE:

BC Hydro does not agree that a potential TSR like rate should be a factor in whether the Commission approves BC Hydro's LGS flat rate proposal; rather the LGS flat proposal should be adjudicated on its own merits. In this regard please refer to section 6.4 of Exhibit B-1.

With respect to a potential TSR-like rate, please refer to BC Hydro's response to BCUC IR 1.68.1.

72.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-57
Extra Large General Service rate

BC Hydro states

While BC Hydro set out considerations for a LGS TSR-Like Rate as a potential rate design for very high consumption LGS customers, it noted that its consideration of a LGS TSR-Like Rate and a segmented LGS class would be proposed only in the overall context of a LGS Flat Energy Rate applicable to the remaining majority of LGS customers. With the support of stakeholders, notably AMPC, a LGS TSR-Like Rate will be explored in RDA Module 2.

1.72.2.1 Would the TSR-like LGS rate for high consumption LGS customers include features of the TSR rate such as the use of bill neutrality definition?

RESPONSE:

BC Hydro has not considered the detailed design of a TSR-like rate at this time. BC Hydro committed to undertake additional engagement with AMPC and LGS customers who potentially would take service under a LGS TSR-Like Rate, and to bring forward our analysis as part of RDA Module 2.

72.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-57
Extra Large General Service rate

BC Hydro states

While BC Hydro set out considerations for a LGS TSR-Like Rate as a potential rate design for very high consumption LGS customers, it noted that its consideration of a LGS TSR-Like Rate and a segmented LGS class would be proposed only in the overall context of a LGS Flat Energy Rate applicable to the remaining majority of LGS customers. With the support of stakeholders, notably AMPC, a LGS TSR-Like Rate will be explored in RDA Module 2.

1.72.3 Based on BC Hydro's knowledge of the customers that may become eligible for the TSR-like rate, how likely are they to take advantage of the new rate to achieve meaningful conservation?

RESPONSE:

BC Hydro cannot speculate on the likelihood of customer conservation in response to a TSR-like rate that is currently only a design concept.

72.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-57
Extra Large General Service rate

BC Hydro states

While BC Hydro set out considerations for a LGS TSR-Like Rate as a potential rate design for very high consumption LGS customers, it noted that its consideration of a LGS TSR-Like Rate and a segmented LGS class would be proposed only in the overall context of a LGS Flat Energy Rate applicable to the remaining majority of LGS customers. With the support of stakeholders, notably AMPC, a LGS TSR-Like Rate will be explored in RDA Module 2.

1.72.4 BC Hydro has intimated that the X-LGS threshold for eligibility may be set at about 2 MW. Please provide a discussion of the number of customers that would be eligible for the rate and its likely conservation potential if the threshold were set at 1 MW, 1.5 MW or 2 MW?

RESPONSE:

Please refer to page 44 of the Workshop 8a/8b Consideration Memo at Appendix C4-A of Exhibit B-1 (page 199 of 813) for a summary of the estimated number of LGS accounts at different kW breakpoints. The number of accounts at 1 MW, 1.5 MW and 2 MW are, respectively 437, 251 and 172.

As described in BC Hydro's response to BCUC IR 1.72.3, BC Hydro cannot speculate on the likelihood of customer conservation in response to a TSR-like rate that is currently only a design concept.

73.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.4.4.2 Screening of Alternatives and Stakeholder Engagement, p. 6-58 Demand cost recovery

On page 6-58, BC Hydro indicates that an increase in LGS demand charge recovery of demand costs from about 50 percent to 65 percent would be a level consistent with RS 1823 demand cost recovery. It further says that an increase in demand cost recovery will improve fairness in cost allocation and will further offset the impacts of energy rate flattening.

1.73.1 BC Hydro describes in the Application that the LGS is a heterogeneous group with the median consumption by site type having a very large range. Why is it important for the LGS rate class to have its recovery of demand cost consistent with RS 1823 and not consistent with the MGS rate class recovery?

RESPONSE:

Three factors informed BC Hydro's position with respect to LGS demand charge recovery of demand-related costs:

- **There is not a 'correct' level of demand-related cost recovery to target in isolation of other factors;**
- **The existing level of such recovery, which is about 50 per cent for LGS customers. In contrast, the existing MGS demand charge recovery of demand related cost is about 15 per cent. On this basis alone, the MGS demand charge is not the appropriate reference; and**
- **Stakeholder feedback and in particular AMPC suggestion that BC Hydro look to the RS 1823 demand charge recovery of demand-related costs. Examination of RS 1823 aligns with BC Hydro's prioritization of BC Hydro's Bonbright fairness and customer understanding criteria (more fairly recovering embedded demand cost recovery while more evenly distributing the bill impacts of BC Hydro LGS rate structure proposals among customers of differing load factor and consumption levels). Accordingly, a decrease in LGS demand charges was not considered appropriate.**

73.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.4.4.2 Screening of Alternatives and Stakeholder Engagement, p. 6-58 Demand cost recovery

On page 6-58, BC Hydro indicates that an increase in LGS demand charge recovery of demand costs from about 50 percent to 65 percent would be a level consistent with RS 1823 demand cost recovery. It further says that an increase in demand cost recovery will improve fairness in cost allocation and will further offset the impacts of energy rate flattening.

1.73.2 In the past three years, what were the migration pattern between MGS and LGS? What were the bill impacts under the existing tariffs for those who migrated?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.62.2.

74.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-59
Large General Service rate

BC Hydro states "BC Hydro prefers to maintain the level of the LGS demand ratchet at the existing level of 50 per cent of peak monthly demand given that the level of the demand ratchet is not a major issue."

1.74.1 From a customer fairness perspective, would a 75 percent ratchet be fairer overall to customers in the LGS class than a 50 percent ratchet?

RESPONSE:

An increase in the level of the LGS demand ratchet would improve fairness in customer contribution to the infrastructure costs that BC Hydro incurs to serve the peak demand of its LGS customers. However, two factors inform BC Hydro's proposal to leave the demand ratchet as is:

- **The 2015 RDA Stakeholder engagement revealed that the level of the LGS demand ratchet charge is not a major issue;**
- **An increase to the LGS demand ratchet to 75 per cent would have adverse bill impacts to those customers that incur the ratchet due to the nature of their operations, as set out in the Workshop 11a/11b consideration memo in Appendix C-4B Exhibit B-1, pages 212-214 of 382.**

74.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, p. 6-59
Large General Service rate

BC Hydro states "BC Hydro prefers to maintain the level of the LGS demand ratchet at the existing level of 50 per cent of peak monthly demand given that the level of the demand ratchet is not a major issue."

1.74.2 If an X-LGS class were created, would the appropriate demand ratchet be 50 percent or 75 percent? Why?

RESPONSE:

This question will be considered in RDA Module 2 as part of the design of a potential TSR-like rate.

75.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.4.5.1 LGS Flat Rate, p. 6-60 Trade-offs of Bonbright criteria

On page 6-60, BC Hydro says that the gains in simplification in moving to a flat energy rate appear to be worth the apparent small loss in economic efficiency in the status quo LGS rate design.

1.75.1 According to the figures in Table 6-10 on page 6-50, the flat energy rate will be 5.37 cents/kWh under the 65 percent demand-related cost recovery. Please explain how BC Hydro reaches its conclusion on the "small losses in economic efficiency."

RESPONSE:

The description of "small loss in economic efficiency" should have been described as an expected small loss in the conservation delivered through the existing LGS two-part rates given (1) the relatively small amounts of conservation delivered by the LGS status-quo two-part rates to date, and (2) BC Hydro's forecast of zero conservation from the status quo LGS two-part rate if the rate structure were to continue.

75.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.4.5.1 LGS Flat Rate, p. 6-60 Trade-offs of Bonbright criteria

On page 6-60, BC Hydro says that the gains in simplification in moving to a flat energy rate appear to be worth the apparent small loss in economic efficiency in the status quo LGS rate design.

1.75.2 Will the new flat rate under either demand charge recovery scenario encourage energy conservation in electricity? Has BC Hydro made any projections of the increase in electric consumption against the status quo under the 65 percent demand-related cost recovery? What is the price elasticity assumed for flat rate consumption?

RESPONSE:

BC Hydro has not modelled consumption forecasts separately under the existing LGS rate, the SQ LGS Simplified rate alternative and the proposed default LGS flat rate:

- **The forecasted rate-structure induced conservation for the existing LGS rate and for the SQ LGS Simplified rate is zero kWh for F2017, F2018, and F2019. The F2014 LGS and MGS Evaluation Report indicated no statistically significant rate structure induced conservation attributable to marginal price response on the existing LGS rate at the 90 per cent confidence level, which BC Hydro's model is based on; and**

- **BC Hydro has no further information on the LGS rate class to construct further conservation models, given the evaluation outcome. BC Hydro also has no evidence to suggest that a flat LGS rate will substantially change consumption behaviour when compared to the existing LGS rate.**

The focus of the 2015 RDA changes is improving rate simplicity and customer understanding, rather than to induce conservation. Given the limited response to the existing LGS rate, which have higher energy rates for incremental changes in consumption that are closer to LRMC but are difficult to understand, the potential for lost rate structure conservation is relatively small. There will also be no change in natural conservation given the assumed elasticity of -0.05 applied to RRA increases.

76.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.4.3.2, Evaluation Results, p. 6-47, and Section 6.4.5.1 LGS Flat Rate, p. 6-60 Simplified energy rate and flat energy rate

The LGS evaluation results indicate that the status quo LGS is administratively complex and BC Hydro had encountered significant operational challenges.

1.76.1 Has BC Hydro made any estimates in regard to the savings in administration and operational costs if either the simplified energy rate or the flat energy flat rate is approved? If so, please provide the savings benefits against the status quo rate.

RESPONSE:

A simplified LGS energy rate would not result in savings, as even a simplified baseline would continue to cause issues relating to the baseline calculation. In addition, customer growth complaints will be the same.

A flat energy rate would potentially result in savings of $0.1 to $0.2 million annually as a result of reduced effort in billing and IT.

77.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.6 Requested Order New Account Rule, pp. 6-70 and 6-71
Change in ownership and85/15 pricing energy rate and flat energy rate

On page 6-70, BC Hydro states that in its previous 2009 LGS Application, BC Hydro proposed 90 percent of monthly consumption billed at Part 1 energy rate and 10 percent of monthly consumption billed at the Part 2 energy rate. The 10 percent was increased to 15 percent during the LGS NSA.

The 85/15 pricing applies to new accounts (e.g., those opened as a result of a legal change in ownership) that have taken over existing businesses and not changed operations. There have been a number of LGS and MGS customer complaints about the 85/15 pricing.

1.77.1 Does BC Hydro agree that in the regulatory context, a change in ownership may be the basis of a rate's availability or the application of conditions to serving a rate? For example: (a) in the 1991 RDA Decision, it was determined that BC Hydro may terminate rate availability when there is a change in ownership to RS 1278 (see page 6-3); and (b) for E-plus rates to residential and commercial customers, a change in ownership would restrict the ability to transfer the E-plus rate to a new customer (see page 5-49).

RESPONSE:

The MGS/LGS 85/15 pricing and the examples cited are not comparable.

RS 1278 and the E-Plus rates are closed rates. Restricting the availability of a closed rate with a change in ownership is appropriate so as not to perpetuate the closed rate.

The MGS and LGS rates are not closed rates and the 85/15 Pricing component of those rates is for new accounts (i.e., a change in ownership) without historical consumption upon which to establish a baseline. The 85/15 Pricing was intended in part to prevent customers from 'gaming' the MGS and LGS rates by opening a new account to avoid the Part 2 LRMC-based rates. As noted in the LGS and MGS Three-Year Report (found at Appendix C-4A to Exhibit B-1, starting at page 561 of 813) BC Hydro found no evidence of 'gaming' occurring.

BC Hydro's proposal to amend the MGS and LGS 85/15 pricing to 100 per cent Part 1 Pricing will continue to be contingent on the opening of a new account.

78.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.6 Requested Order New Account Rule, p. 6-70; Exhibit A2-1 BC Hydro request for reconsideration of Order G-64-11
Requested order for LGS and MGS new account rule

In the 2009 LGS Application, BC Hydro proposed 90 percent of monthly consumption billed at the Part 2 energy rate. The 10 percent was increased to 15 percent during the LGS Negotiated Settlement Agreement. This was to reduce the concerns expressed by some stakeholders that existing customers with growing load might open new accounts to have their Historic Baselines (HBL) reset and to obtain bill savings.

1.78.1 TS 82 provides for explicit pricing rules for eligible LGS customers with prospective growth, which is the 85/15 rule. Does BC Hydro agree that the 85/15 pricing is not just for the new account but also for incremental load?

RESPONSE:

Agreed, under the existing LGS tariff 85/15 pricing applies to a new account and under TS 82 it applies to incremental load for an existing account in the first year.

78.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.6 Requested Order New Account Rule, p. 6-70; Exhibit A2-1 BC Hydro request for reconsideration of Order G-64-11
Requested order for LGS and MGS new account rule

In the 2009 LGS Application, BC Hydro proposed 90 percent of monthly consumption billed at the Part 2 energy rate. The 10 percent was increased to 15 percent during the LGS Negotiated Settlement Agreement. This was to reduce the concerns expressed by some stakeholders that existing customers with growing load might open new accounts to have their Historic Baselines (HBL) reset and to obtain bill savings.

1.78.2 In BC Hydro's view, why is it reasonable to eliminate the 85/15 pricing for new accounts in an accelerated manner, effective January 2016, but not for incremental load?

RESPONSE:

Under the existing LGS rate, there is already different pricing in the first year for load for new accounts and incremental load for an existing account.

Incremental load of an existing account in the first year is priced at the Part 2 energy rate up to 20 per cent of its Historic Baseline (HBL). An existing customer with prospective growth has an option of applying for service under TS 82 where its incremental load in the first year is subject to 85/15 pricing.

BC Hydro's view is that it is difficult to apply the same pricing principle in the first year for all these circumstances. Given that BC Hydro is proposing to eliminate the LGS rate effective April 1, 2017, BC Hydro's preference is to maintain the existing pricing for incremental load of an existing customer so as not to incur additional implementation costs (e.g., billing and customer communication). In addition, and as noted in section 6.6 of Exhibit B-1, LGS and MGS customer complaints have concerned the application of 85/15 pricing to new accounts as opposed to the application TS 82 context.

78.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.6 Requested Order New Account Rule, p. 6-70; Exhibit A2-1 BC Hydro request for reconsideration of Order G-64-11
Requested order for LGS and MGS new account rule

In Exhibit A2-1, a BC Hydro letter dated April 18, 2011 requested a reconsideration of Order G-64-11. Page 4 of 5 in the letter states: "85/15 Pricing is an appropriate price signal to new load that BC Hydro would otherwise serve at embedded cost." On page 6-71, lines 13 to 16, BC Hydro says that " BC Hydro proposes that new MGS and LGS accounts pay 100 percent Part 1 Pricing. This pricing recovers BC Hydro's embedded costs and therefore does not harm other ratepayers. Although new accounts will not be exposed to the LRMC price signal, this will be for a one year period only."

1.78.3 Please explain why BC Hydro on page 6-71, line 14 describes that a one year period is acceptable for new accounts not being exposed to the LRMC.

RESPONSE:

BC Hydro believes that this is acceptable given the minimal conservation achieved from the two-part LGS rate structure and no conservation from MGS two-part rate structure and is consistent with BC Hydro's proposed MGS and LGS flat energy rates.

78.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.6 Requested Order New Account Rule, p. 6-70; Exhibit A2-1 BC Hydro request for reconsideration of Order G-64-11
Requested order for LGS and MGS new account rule

In Exhibit A2-1, on page 4 of 5, BC Hydro states:

Neither the Interfor Application nor the impugned order address the issue of fairness between new accounts and existing accounts with "significant, permanent increases in energy consumption" as defined in section 13 of the LGS NSA. Thus, on the face, the effect of BCUC Order No. G-64-11 is *prima facie* an undue preference to existing customers vis-à-vis new customers subject to the 85-15 rule.

1.78.4 Please address the fairness issue in the accelerated request for a change in pricing for the new account rule?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.78.2.

79.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.5.1 Medium General Service, p. 6-68
Medium General Service phase-in

On page 6-68 BC Hydro states

A three-year phase-in period for BC Hydro's preferred MGS rate (F2017-F2019) would have only minor mitigation of bill impacts as compared to no phase-in (i.e., one-time F2018 implementation) impacts:

- Under a three-year phase-in, customers who experience adverse bill impacts greater than 10 per cent are limited to about 800 accounts with less than about 40 MWh/year of annual consumption; and
- For the majority of MGS customers the three-year phase-in will delay the offsetting effect of the flat energy rate, flat demand charge and increasing demand cost recovery. "

And "The three-year phase-in is highly complex. While there are some softening of bill impacts for high load factor, high consuming customers, the key trade-off is an expected decline in customer understanding and bill predictability.

1.79.1 Please expand on the "highly complex" nature of a three-year phase-in?

RESPONSE:

Computation of the rates during the phase-in requires simulation modelling, using inputs such as billing data and forecasts of revenue and load. The technical complexity of the phase-in comes from the following three components of the MGS rate that are synchronized and adjusted simultaneously while ensuring forecast revenue neutrality to the existing MGS rate:

1. **Increasing demand charge revenue recovery from 16 per cent to 35 per cent over three years;**

2. **Flattening of the energy charges over three years; and**

3. **Flattening of the three-step demand charges, including escalating the Tier 1 charge from $0 and adjustment of Tier 2 and Tier 3 changes over three years.**

For customers, the complexity would be caused by the multiple rate components that would be changing each rate cycle. BC Hydro is of the view that the combination of the phased demand and energy charge flattening along with the redistribution of cost recovery between the energy and demand charges would make it difficult for customers to understand.

79.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.5.1 Medium General Service, p. 6-68
Medium General Service phase-in

On page 6-68 BC Hydro states

A three-year phase-in period for BC Hydro's preferred MGS rate (F2017-F2019) would have only minor mitigation of bill impacts as compared to no phase-in (i.e., one-time F2018 implementation) impacts:

- Under a three-year phase-in, customers who experience adverse bill impacts greater than 10 per cent are limited to about 800 accounts with less than about 40 MWh/year of annual consumption; and
- For the majority of MGS customers the three-year phase-in will delay the offsetting effect of the flat energy rate, flat demand charge and increasing demand cost recovery. "

And "The three-year phase-in is highly complex. While there are some softening of bill impacts for high load factor, high consuming customers, the key trade-off is an expected decline in customer understanding and bill predictability.

1.79.2 Please explain how BC Hydro evaluated and weighted the competing rate design objectives of bill complexity, customer impacts and conservation to conclude that no phase-in was preferable for MGS customers?

RESPONSE:

BC Hydro did not use explicit weights to balance competing objectives in coming to the proposal to not recommend a three year phase-in period for the proposed MGS flat rate. The bill impacts of moving directly to the MGS flat rate seemed worth the added complexity of developing and implementing a phase in process; in this regard, please refer to BC Hydro's response to BCUC IR 1.79.1.

As stated in Exhibit B-1, Appendix C-4B, page 379, the MGS phase-in softens bill impacts only modestly, and BC Hydro's simulations show that in F2017, the maximum bill impact of the largest MGS customers is about 8 per cent vs. the no-phase-in of 10.4 per cent. Furthermore, there are no substantive differences on the maximum bill impact of typical customers, at 3.2 per cent for phase-in vs. 2.8 per cent for no phase-in, and both are under the RRA increase of 4 per cent. Finally, under the no-phase-in scenario, the highest bill impact in terms of nominal dollars (with low consumption and low load factor customer) is modest at $6,000, with a bill impact of 14 per cent, as stated on Exhibit B-1, page 6-35.

The MGS rate change is unique in that the changes to energy charges and demand charges result in offsetting bill impacts for many customers - limiting the combined impact of the changes. That is why the phase-in of the proposed MGS rate is not that effective at mitigating the bill impacts of the design change.

Given the poor understanding of the existing rate by MGS customers, BC Hydro cannot produce a meaningful estimate of customer usage changes from the existing rate. The total rate-structure conservation for the existing MGS rate is assumed to be zero for F2017 to F2019, regardless of whether there is a phase-in.

Under the Bonbright criteria assessment, the increase in complexity, lower customer understanding and a much delayed adjustment to demand cost recovery outweighs the benefits experienced from a very modest softening of bill impact. Thus, BC Hydro concludes that a three year phase-in is not a preferred option.

80.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.5.1 Medium General Service, p. 6-68
Figure 6-15 Medium General Service three year phase-in bill impacts

Figure 6-15 Three Year MGS Proposed Rates Phase-In

	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	11.5%	11.9%	8.2%	7.3%	6.9%	1.2%	-4.4%	-7.4%	-9.6%	-11.2%	-12.5%	-13.5%	-14.3%	-15.0%	-15.6%	-16.1%	-16.6%
20%	4.8%	4.9%	4.9%	4.1%	3.8%	3.6%	3.6%	4.8%	5.8%	5.7%	3.4%	1.6%	0.1%	-1.2%	-2.2%	-3.1%	-3.9%
30%	2.6%	2.5%	2.5%	2.5%	2.2%	2.1%	2.1%	3.5%	4.5%	5.4%	6.1%	6.6%	7.1%	7.6%	6.4%	5.3%	4.2%
40%	1.5%	1.3%	1.3%	1.3%	1.3%	1.2%	1.2%	2.6%	3.8%	4.6%	5.4%	6.0%	6.5%	6.9%	7.3%	7.7%	8.0%
50%	0.8%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	2.1%	3.2%	4.2%	4.9%	5.6%	6.1%	6.5%	6.9%	7.3%	7.6%
60%	0.4%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	1.7%	2.9%	3.8%	4.6%	5.2%	5.8%	6.3%	6.7%	7.0%	7.3%
70%	0.1%	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%	-0.1%	1.4%	2.6%	3.6%	4.4%	5.0%	5.6%	6.0%	6.5%	6.8%	7.2%
80%	-0.2%	-0.4%	-0.5%	-0.5%	-0.5%	-0.5%	-0.4%	1.2%	2.4%	3.4%	4.2%	4.8%	5.4%	5.9%	6.3%	6.7%	7.0%
90%	-0.4%	-0.6%	-0.7%	-0.7%	-0.7%	-0.7%	-0.6%	1.0%	2.2%	3.2%	4.0%	4.7%	5.3%	5.7%	6.2%	6.5%	6.9%

1.80.1 Please confirm, otherwise explain, that Figure 6-15 shows the summation of the bill impacts of the three-year phase-in period.

RESPONSE:

Exhibit B-1, Figure 6-15 shows the bill impacts for the first year of phase-in (F2017) for MGS.

80.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.5.1 Medium General Service, p. 6-68
Figure 6-15 Medium General Service three year phase-in bill impacts

Figure 6-15 Three Year MGS Proposed Rates Phase-In

	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	11.5%	11.9%	8.2%	7.3%	6.9%	1.2%	-4.4%	-7.4%	-9.6%	-11.2%	-12.5%	-13.5%	-14.3%	-15.0%	-15.6%	-16.1%	-16.6%
20%	4.8%	4.9%	4.9%	4.1%	3.8%	3.6%	3.6%	4.8%	5.8%	5.7%	3.4%	1.6%	0.1%	-1.2%	-2.2%	-3.1%	-3.9%
30%	2.6%	2.5%	2.5%	2.5%	2.2%	2.1%	2.1%	3.5%	4.5%	5.4%	6.1%	6.6%	7.1%	7.6%	6.4%	5.3%	4.2%
40%	1.5%	1.3%	1.3%	1.3%	1.3%	1.2%	1.2%	2.6%	3.8%	4.6%	5.4%	6.0%	6.5%	6.9%	7.3%	7.7%	8.0%
50%	0.8%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	2.1%	3.2%	4.2%	4.9%	5.6%	6.1%	6.5%	6.9%	7.3%	7.6%
60%	0.4%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	1.7%	2.9%	3.8%	4.6%	5.2%	5.8%	6.3%	6.7%	7.0%	7.3%
70%	0.1%	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%	-0.1%	1.4%	2.6%	3.6%	4.4%	5.0%	5.6%	6.0%	6.5%	6.8%	7.2%
80%	-0.2%	-0.4%	-0.5%	-0.5%	-0.5%	-0.5%	-0.4%	1.2%	2.4%	3.4%	4.2%	4.8%	5.4%	5.9%	6.3%	6.7%	7.0%
90%	-0.4%	-0.6%	-0.7%	-0.7%	-0.7%	-0.7%	-0.6%	1.0%	2.2%	3.2%	4.0%	4.7%	5.3%	5.7%	6.2%	6.5%	6.9%

1.80.2 Please provide a bill impact table similar to Figure 6-15 for each year of three year phase-in period.

RESPONSE:

The requested MGS phase-in information, based on the same vintage of assumptions as used in Exhibit B-1, Figure 6-15, is as follows:

Bill Impact for F2017
(RRA = 4 per cent; red font indicates bill impacts higher than RRA)

	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	11.5%	11.9%	8.2%	7.3%	6.9%	1.2%	-4.4%	-7.4%	-9.6%	-11.2%	-12.5%	-13.5%	-14.3%	-15.0%	-15.6%	-16.1%	-16.6%
20%	4.8%	4.9%	4.9%	4.1%	3.8%	3.6%	3.6%	4.8%	5.8%	5.7%	3.4%	1.6%	0.1%	-1.2%	-2.2%	-3.1%	-3.9%
30%	2.6%	2.5%	2.5%	2.5%	2.2%	2.1%	2.1%	3.5%	4.5%	5.4%	6.1%	6.6%	7.1%	7.6%	6.4%	5.3%	4.2%
40%	1.5%	1.3%	1.3%	1.3%	1.3%	1.2%	1.2%	2.6%	3.8%	4.6%	5.4%	6.0%	6.5%	6.9%	7.3%	7.7%	8.0%
50%	0.8%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	2.1%	3.2%	4.2%	4.9%	5.6%	6.1%	6.5%	6.9%	7.3%	7.6%
60%	0.4%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	1.7%	2.9%	3.8%	4.6%	5.2%	5.8%	6.3%	6.7%	7.0%	7.3%
70%	0.1%	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%	-0.1%	1.4%	2.6%	3.6%	4.4%	5.0%	5.6%	6.0%	6.5%	6.8%	7.2%
80%	-0.2%	-0.4%	-0.5%	-0.5%	-0.5%	-0.5%	-0.4%	1.2%	2.4%	3.4%	4.2%	4.8%	5.4%	5.9%	6.3%	6.7%	7.0%
90%	-0.4%	-0.6%	-0.7%	-0.7%	-0.7%	-0.7%	-0.6%	1.0%	2.2%	3.2%	4.0%	4.7%	5.3%	5.7%	6.2%	6.5%	6.9%

Cumulative Bill Impact F2017 to F2018
(Cumulative RRA = 7.6 per cent; red font indicates bill impacts higher than Cumulative RRA)

	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	31.3%	32.6%	14.7%	10.4%	8.6%	2.0%	-4.1%	-6.6%	-8.5%	-9.9%	-11.0%	-11.8%	-12.6%	-13.1%	-13.6%	-14.1%	-14.5%
20%	13.5%	13.8%	13.9%	8.7%	6.3%	5.0%	4.4%	6.4%	7.9%	8.2%	6.2%	4.5%	3.2%	2.1%	1.2%	0.4%	-0.3%
30%	7.6%	7.6%	7.6%	7.6%	5.2%	3.8%	3.2%	5.3%	7.0%	8.3%	9.4%	10.3%	11.1%	11.7%	10.8%	9.7%	8.8%
40%	4.6%	4.5%	4.4%	4.4%	4.4%	3.1%	2.4%	4.7%	6.4%	7.8%	9.0%	10.0%	10.8%	11.5%	12.1%	12.6%	13.1%
50%	2.8%	2.6%	2.5%	2.5%	2.5%	2.5%	1.9%	4.2%	6.1%	7.5%	8.7%	9.7%	10.6%	11.3%	11.9%	12.5%	13.0%
60%	1.7%	1.3%	1.2%	1.2%	1.2%	1.2%	1.5%	3.9%	5.8%	7.3%	8.5%	9.6%	10.4%	11.2%	11.8%	12.4%	12.9%
70%	0.8%	0.4%	0.3%	0.3%	0.3%	0.3%	0.8%	3.6%	5.6%	7.1%	8.4%	9.4%	10.3%	11.1%	11.8%	12.4%	12.9%
80%	0.2%	-0.2%	-0.3%	-0.4%	-0.4%	-0.4%	-0.1%	2.9%	5.4%	7.0%	8.3%	9.3%	10.3%	11.0%	11.7%	12.3%	12.8%
90%	-0.3%	-0.7%	-0.9%	-0.9%	-0.9%	-0.9%	-0.7%	2.3%	4.8%	6.8%	8.2%	9.3%	10.2%	11.0%	11.7%	12.3%	12.8%

Cumulative Bill Impact F2017 to F2019
(Cumulative RRA = 10.9 per cent; red font indicates bill impacts higher than Cumulative RRA)

	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	60.0%	62.7%	19.5%	9.3%	4.8%	-3.0%	-9.6%	-12.0%	-13.7%	-15.0%	-16.0%	-16.8%	-17.4%	-18.0%	-18.4%	-18.8%	-19.2%
20%	26.5%	27.3%	27.5%	13.9%	7.7%	4.3%	2.5%	4.5%	6.0%	6.5%	4.5%	2.9%	1.6%	0.6%	-0.3%	-1.1%	-1.7%
30%	15.3%	15.5%	15.6%	15.6%	9.2%	5.3%	3.3%	5.5%	7.3%	8.7%	9.9%	10.8%	11.6%	12.3%	11.4%	10.4%	9.5%
40%	9.7%	9.6%	9.6%	9.6%	9.6%	5.9%	3.7%	6.1%	8.0%	9.5%	10.8%	11.8%	12.7%	13.4%	14.1%	14.7%	15.2%
50%	6.3%	6.1%	6.0%	6.0%	6.0%	6.0%	4.0%	6.6%	8.5%	10.1%	11.4%	12.5%	13.4%	14.2%	14.9%	15.5%	16.0%
60%	4.1%	3.7%	3.6%	3.6%	3.6%	3.6%	4.0%	6.8%	8.9%	10.5%	11.8%	12.9%	13.9%	14.7%	15.4%	16.0%	16.6%
70%	2.5%	2.0%	1.9%	1.9%	1.9%	1.8%	2.2%	5.8%	9.1%	10.8%	12.2%	13.3%	14.3%	15.1%	15.8%	16.5%	17.0%
80%	1.3%	0.8%	0.6%	0.6%	0.6%	0.6%	0.9%	5.4%	9.1%	11.0%	12.4%	13.6%	14.6%	15.4%	16.1%	16.8%	17.4%
90%	0.4%	-0.2%	-0.4%	-0.4%	-0.4%	-0.5%	-0.1%	4.4%	8.0%	11.0%	12.6%	13.8%	14.8%	15.7%	16.4%	17.1%	17.6%

81.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.5.2 Large General Service, p. 6-70
Figure 6-17 Large General Service three year phase-in bill impacts

Figure 6-17 Three Year LGS Preferred Rates Phase-In

	150,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	25.2%	2.4%	-1.5%	-3.3%	-4.5%	-5.2%	-5.8%	-6.2%	-6.5%	-6.7%	-6.9%	-7.1%	-7.2%	-7.4%	-7.5%	-7.6%	-7.6%
20%	13.8%	12.3%	6.1%	[illegible]	[illegible]	0.0%	-0.8%	-1.5%	-2.0%	-2.4%	-2.7%	-3.0%	-3.2%	-3.4%	-3.5%	-3.7%	-3.8%
30%	4.2%	19.0%	[illegible]	7.3%	5.0%	3.5%	2.4%	1.6%	1.0%	0.5%	0.1%	-0.2%	-0.5%	-0.8%	-1.0%	-1.2%	-1.3%
40%	-1.4%	13.7%	14.7%	10.3%	7.7%	6.0%	4.7%	3.8%	3.1%	2.5%	2.1%	1.7%	1.4%	1.1%	0.8%	0.6%	0.5%
50%	-4.9%	9.8%	14.8%	12.6%	9.7%	7.8%	6.5%	5.5%	4.7%	4.1%	3.6%	3.1%	2.8%	2.5%	2.2%	2.0%	1.8%
60%	-6.1%	6.9%	11.9%	14.3%	11.3%	9.2%	7.8%	6.7%	5.9%	5.2%	4.7%	4.2%	3.9%	3.5%	3.3%	3.0%	2.8%
70%	-7.1%	4.8%	9.7%	12.5%	[illegible]	[illegible]	8.9%	7.7%	6.9%	6.2%	5.6%	5.1%	4.7%	4.4%	4.1%	3.8%	3.6%
80%	-7.8%	3.2%	8.0%	10.7%	12.5%	11.3%	9.7%	8.6%	7.7%	6.9%	6.3%	5.9%	5.4%	5.1%	4.8%	4.5%	4.3%
90%	-8.3%	1.9%	6.6%	9.4%	11.1%	12.1%	10.5%	9.3%	8.3%	7.6%	7.0%	6.5%	6.0%	5.7%	5.3%	5.1%	4.8%

1.81.1 Please confirm, otherwise explain, that Figure 6-17 shows the summation of the bill impacts of the three-year phase-in period.

RESPONSE:

Exhibit B-1, Figure 6-17 shows the bill impacts for the first year of phase-in (F2017) for LGS.

81.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 6.5.2 Large General Service, p. 6-70 Figure 6-17 Large General Service three year phase-in bill impacts

Figure 6-17 Three Year LGS Preferred Rates Phase-In

	150,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	25.2%	2.4%	-1.5%	-3.3%	-4.5%	-5.2%	-5.8%	-6.2%	-6.5%	-6.7%	-6.9%	-7.1%	-7.2%	-7.4%	-7.5%	-7.6%	-7.6%
20%	13.8%	12.3%	6.1%	3.1%	1.2%	0.0%	-0.8%	-1.5%	-2.0%	-2.4%	-2.7%	-3.0%	-3.2%	-3.4%	-3.5%	-3.7%	-3.8%
30%	4.2%	19.0%	11.1%	7.3%	5.0%	3.5%	2.4%	1.6%	1.0%	0.5%	0.1%	-0.2%	-0.5%	-0.8%	-1.0%	-1.2%	-1.3%
40%	-1.4%	13.7%	14.7%	10.3%	7.7%	6.0%	4.7%	3.8%	3.1%	2.5%	2.1%	1.7%	1.4%	1.1%	0.8%	0.6%	0.5%
50%	-4.9%	9.8%	14.8%	12.6%	9.7%	7.8%	6.5%	5.5%	4.7%	4.1%	3.6%	3.1%	2.8%	2.5%	2.2%	2.0%	1.8%
60%	-6.1%	6.9%	11.9%	14.3%	11.3%	9.2%	7.8%	6.7%	5.9%	5.2%	4.7%	4.2%	3.9%	3.5%	3.3%	3.0%	2.8%
70%	-7.1%	4.8%	9.7%	12.5%	12.5%	10.4%	8.9%	7.7%	6.9%	6.2%	5.6%	5.1%	4.7%	4.4%	4.1%	3.8%	3.6%
80%	-7.8%	3.2%	8.0%	10.7%	12.5%	11.3%	9.7%	8.6%	7.7%	6.9%	6.3%	5.9%	5.4%	5.1%	4.8%	4.5%	4.3%
90%	-8.3%	1.9%	6.6%	9.4%	11.1%	12.1%	10.5%	9.3%	8.3%	7.6%	7.0%	6.5%	6.0%	5.7%	5.3%	5.1%	4.8%

1.81.2 Please provide a bill impact table similar to Figure 6-17 for each year of three-year phase-in period.

RESPONSE:

The requested LGS phase-in information, based on the same vintage of assumptions as used in Exhibit B-1, Figure 6-17, is as follows:

Bill Impact for F2017

(RRA = 4%; red font indicates bill impacts higher than RRA)

	150,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	25.2%	2.4%	-1.5%	-3.3%	-4.5%	-5.2%	-5.8%	-6.2%	-6.5%	-6.7%	-6.9%	-7.1%	-7.2%	-7.4%	-7.5%	-7.6%	-7.6%
20%	13.8%	12.3%	6.1%	3.1%	1.2%	0.0%	-0.8%	-1.5%	-2.0%	-2.4%	-2.7%	-3.0%	-3.2%	-3.4%	-3.5%	-3.7%	-3.8%
30%	4.2%	19.0%	11.1%	7.3%	5.0%	3.5%	2.4%	1.6%	1.0%	0.5%	0.1%	-0.2%	-0.5%	-0.8%	-1.0%	-1.2%	-1.3%
40%	-1.4%	13.7%	14.7%	10.3%	7.7%	6.0%	4.7%	3.8%	3.1%	2.5%	2.1%	1.7%	1.4%	1.1%	0.8%	0.6%	0.5%
50%	-4.9%	9.8%	14.8%	12.6%	9.7%	7.8%	6.5%	5.5%	4.7%	4.1%	3.6%	3.1%	2.8%	2.5%	2.2%	2.0%	1.8%
60%	-6.1%	6.9%	11.9%	14.3%	11.3%	9.2%	7.8%	6.7%	5.9%	5.2%	4.7%	4.2%	3.9%	3.5%	3.3%	3.0%	2.8%
70%	-7.1%	4.8%	9.7%	12.5%	12.5%	10.4%	8.9%	7.7%	6.9%	6.2%	5.6%	5.1%	4.7%	4.4%	4.1%	3.8%	3.6%
80%	-7.8%	3.2%	8.0%	10.7%	12.5%	11.3%	9.7%	8.6%	7.7%	6.9%	6.3%	5.9%	5.4%	5.1%	4.8%	4.5%	4.3%
90%	-8.3%	1.9%	6.6%	9.4%	11.1%	12.1%	10.5%	9.3%	8.3%	7.6%	7.0%	6.5%	6.0%	5.7%	5.3%	5.1%	4.8%

Cumulative Bill Impact F2017 to F2018

(Cumulative RRA = 7.6%; red font indicates bill impacts higher than Cumulative RRA)

	150,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	22.8%	5.9%	3.5%	2.4%	1.7%	1.2%	0.9%	0.6%	0.5%	0.3%	0.2%	0.1%	0.0%	-0.1%	-0.2%	-0.2%	-0.3%
20%	9.0%	12.3%	8.5%	6.7%	5.5%	4.8%	4.3%	3.9%	3.6%	3.3%	3.1%	3.0%	2.8%	2.7%	2.6%	2.5%	2.4%
30%	-1.2%	16.7%	11.9%	9.5%	8.1%	7.2%	6.5%	6.0%	5.6%	5.3%	5.1%	4.9%	4.7%	4.5%	4.4%	4.3%	4.2%
40%	-7.1%	11.1%	14.2%	11.5%	9.9%	8.8%	8.1%	7.5%	7.1%	6.7%	6.4%	6.2%	6.0%	5.8%	5.7%	5.5%	5.4%
50%	-11.0%	7.0%	13.7%	13.0%	11.3%	10.1%	9.3%	8.6%	8.2%	7.8%	7.5%	7.2%	7.0%	6.8%	6.6%	6.5%	6.4%
60%	-13.9%	4.1%	10.7%	14.2%	12.3%	11.1%	10.2%	9.5%	9.0%	8.6%	8.3%	8.0%	7.7%	7.5%	7.4%	7.2%	7.1%
70%	-15.9%	1.9%	8.5%	12.3%	13.1%	11.8%	10.9%	10.2%	9.7%	9.2%	8.9%	8.6%	8.4%	8.1%	8.0%	7.8%	7.7%
80%	-17.5%	0.2%	6.8%	10.5%	12.9%	12.5%	11.5%	10.8%	10.2%	9.8%	9.4%	9.1%	8.8%	8.6%	8.4%	8.3%	8.1%
90%	-18.6%	-1.2%	5.4%	9.2%	11.5%	13.0%	12.0%	11.2%	10.7%	10.2%	9.8%	9.5%	9.3%	9.0%	8.8%	8.7%	8.5%

Cumulative Bill Impact F2017 to F2019

(Cumulative RRA = 10.9%; red font indicates bill impacts higher than Cumulative RRA)

	150,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	19.4%	9.0%	8.2%	7.9%	7.7%	7.5%	7.4%	7.3%	7.3%	7.2%	7.2%	7.2%	7.1%	7.1%	7.1%	7.1%	7.0%
20%	3.8%	11.8%	10.6%	10.0%	9.6%	9.4%	9.2%	9.1%	9.0%	8.9%	8.8%	8.8%	8.8%	8.7%	8.7%	8.6%	8.6%
30%	-6.6%	13.7%	12.1%	11.4%	10.9%	10.6%	10.4%	10.2%	10.1%	10.0%	9.9%	9.9%	9.8%	9.8%	9.7%	9.7%	9.7%
40%	-12.6%	8.0%	13.2%	12.3%	11.8%	11.5%	11.2%	11.1%	10.9%	10.8%	10.7%	10.6%	10.6%	10.5%	10.5%	10.4%	10.4%
50%	-16.9%	3.9%	12.1%	13.1%	12.5%	12.1%	11.9%	11.7%	11.5%	11.4%	11.3%	11.2%	11.1%	11.1%	11.0%	11.0%	10.9%
60%	-21.6%	1.0%	9.8%	13.6%	13.0%	12.6%	12.4%	12.1%	12.0%	11.8%	11.7%	11.7%	11.6%	11.5%	11.5%	11.4%	11.4%
70%	-24.9%	-1.2%	7.1%	11.7%	13.5%	13.0%	12.7%	12.5%	12.3%	12.2%	12.1%	12.0%	11.9%	11.9%	11.8%	11.7%	11.7%
80%	-27.4%	-2.9%	5.4%	10.1%	13.1%	13.4%	13.1%	12.8%	12.7%	12.5%	12.4%	12.3%	12.2%	12.1%	12.1%	12.0%	12.0%
90%	-29.4%	-4.3%	4.0%	8.7%	11.7%	13.6%	13.3%	13.1%	12.9%	12.8%	12.6%	12.5%	12.4%	12.4%	12.3%	12.3%	12.2%

82.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, p. 6-37, 6-56 and 6-67
Figure 6-17 Medium General Service phase-in

In the Application BC Hydro notes on page 6-56: "AMPC questioned whether higher bill impacts to high load factor and high consumption customers would be fair and acceptable given that such customers make more efficient use of BC Hydro's system." Further, BC Hydro notes on page 6-37 "AMPC notes that it believes that the MGS Demand Sensitivity outcome is not acceptable given that high load factor customers make more efficient use of BC Hydro's system."

And explains on page 6-67:

The benefits of more efficient rate design is that they would encourage efficient customer behavior that would lower customer bills in the future and it made sense that rates could transition to being more efficient to mitigate severe bill impacts on a few customers for the benefit of all customers…BC Hydro is proposing to redesign rates that unfairly allocate fixed costs among customers and have been doing so for some time now. Delays or lengthy transitions lengthen the time that some customers are required to subsidize others.

BC Hydro further explains on page 6-68: "The three-year phase-in is highly complex. While there are some softening of bill impacts for high load factor, high consuming customers, the key trade-off is an expected decline in customer understanding and bill predictability."

1.82.1 Please explain what BC Hydro considers efficient customer behavior.

RESPONSE:

In the context of this IR, BC Hydro considers efficiency to be in respect of use of BC Hydro's system. As described in response to BCUC IR 1.82.2, customers consuming with a higher load factor make more efficient use of BC Hydro's system than ones with a low load factor. Because BC Hydro needs to construct facilities to meet customer peak demand, a customer with a higher load factor makes more consistent use of BC Hydro facilities and can generally require less BC Hydro capacity to serve them than a customer consuming the same amount of annual energy, but with a lower load factor. Of course, this is only a general statement, as a customer with a lower load factor, if their peak occurs at off-peak times, could actually place less demands on BC Hydro facilities than a high load factor customer.

82.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, p. 6-37, 6-56 and 6-67
Figure 6-17 Medium General Service phase-in

In the Application BC Hydro notes on page 6-56: "AMPC questioned whether higher bill impacts to high load factor and high consumption customers would be fair and acceptable given that such customers make more efficient use of BC Hydro's system." Further, BC Hydro notes on page 6-37 "AMPC notes that it believes that the MGS Demand Sensitivity outcome is not acceptable given that high load factor customers make more efficient use of BC Hydro's system."

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BC Hydro further explains on page 6-68: "The three-year phase-in is highly complex. While there are some softening of bill impacts for high load factor, high consuming customers, the key trade-off is an expected decline in customer understanding and bill predictability."

1.82.2 Please explain how BC Hydro calculates load factor. Assuming all else equal, does BC Hydro consider a customer consuming with a higher load factor a more efficient customer than one with a low load factor, or vice versa? Please explain.

RESPONSE:

Load factor is calculated as equal to: Annual kWh/(Max Annual kW x 365 days/year x 24 hrs/day). It is the ratio of actual kWh used in a given period to the total possible kWh that could be used in the same period at peak kW consumption.

Assuming all else equal, BC Hydro considers customers consuming with a higher load factor to make more efficient use of BC Hydro's system than ones with a low load factor:

- **Customers with high load factors generally have lower total costs on a per unit (kWh) basis than low load factor customers; and**
- **A customer with a high load factor has use that is relatively constant and a higher utilization of its peak demand, and thus is considered to be utilizing BC Hydro's system more efficiently than low load factor customers (unless the low load**

factor customer has its peak usage at times of low BC Hydro system and transmission and distribution peak demand). High load factor customers contribute to improving system load factor and reduce the per unit recovery of demand costs in the energy charge.

As described in detail in sections 6.3 and 6.4 of Exhibit B-1, BC Hydro's proposals to increase the MGS and LGS demand cost recovery reflects the above consideration and improves fairness in how costs are recovered. Other primary considerations included bill impacts to customers and whether the rates are practical and easily understood.

82.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, p. 6-37, 6-56 and 6-67
Figure 6-17 Medium General Service phase-in

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BC Hydro further explains on page 6-68: "The three-year phase-in is highly complex. While there are some softening of bill impacts for high load factor, high consuming customers, the key trade-off is an expected decline in customer understanding and bill predictability."

1.82.3 Under the current rate structure, are high load factor customers subsidizing low load factor customers, or vice versa? Please explain.

RESPONSE:

Because of the sensitivity of demand bill to customer size, BC Hydro cannot theorize which group is subsidizing the other at this time under the current MGS rate. Nevertheless, BC Hydro offers the following general observation. Under the current MGS rate, the demand charge only partially recovers demand-related costs. Because the residual demand-related costs are collected via uniform energy charges, the higher load factor customers will generally pay more than they would have if the demand-related costs were collected wholly through demand charges. This means that for customers with the same demand, the high load factor customer is subsidizing the low load factor customers, other consumption patterns being equal.

82.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, p. 6-37, 6-56 and 6-67
Figure 6-17 Medium General Service phase-in

In the Application BC Hydro notes on page 6-56: "AMPC questioned whether higher bill impacts to high load factor and high consumption customers would be fair and acceptable given that such customers make more efficient use of BC Hydro's system." Further, BC Hydro notes on page 6-37 "AMPC notes that it believes that the MGS Demand Sensitivity outcome is not acceptable given that high load factor customers make more efficient use of BC Hydro's system."

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BC Hydro further explains on page 6-68: "The three-year phase-in is highly complex. While there are some softening of bill impacts for high load factor, high consuming customers, the key trade-off is an expected decline in customer understanding and bill predictability."

1.82.4 Under the current rate structure, are fixed costs being unfairly allocated to low load factor customers as compared to high load factor customers? Please explain.

RESPONSE:

For purposes of responding to this IR, BC Hydro defines the reference to "fixed costs" as demand-related costs, which are determined in the F2016 COS study and are comprised of generation demand, transmission demand and distribution demand-related costs.

Please refer to BC Hydro's response to BCUC IR 1.82.3.

82.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, p. 6-37, 6-56 and 6-67
Figure 6-17 Medium General Service phase-in

In the Application BC Hydro notes on page 6-56: "AMPC questioned whether higher bill impacts to high load factor and high consumption customers would be fair and acceptable given that such customers make more efficient use of BC Hydro's system." Further, BC Hydro notes on page 6-37 "AMPC notes that it believes that the MGS Demand Sensitivity outcome is not acceptable given that high load factor customers make more efficient use of BC Hydro's system."

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BC Hydro further explains on page 6-68: "The three-year phase-in is highly complex. While there are some softening of bill impacts for high load factor, high consuming customers, the key trade-off is an expected decline in customer understanding and bill predictability."

1.82.5 It appears that high load factor / high consumption MGS and LGS customers would benefit from a three-year phase-in plan. Please explain how the benefits to high load factor / high consumption were traded off and weighed against customer understanding and bill predictability.

RESPONSE:

BC Hydro agrees that there are some high load factor/high consumption MGS customers that would benefit from a three-year phase-in.

The overall consideration informing BC Hydro's no phase in proposal for the LGS and MGS flat rates are as follows:

- **For almost all LGS customers, a phase-in to the proposed LGS rates would delay the offsetting benefits of the LGS rate proposals in their entirety with no significant benefit in mitigating overall bill impacts. (For high load factor/high consumption LGS customers the difference in bill impacts between no phase-in and three-year phase is very small; less than 1 per cent). There is no trade-off associated with proposing not to phase-in to the LGS flat rate proposal when**

weighed against a highly complex implementation that would be difficult for customers to understand and would make bills difficult to predict; and

- **For MGS customers, while it is true that some high load factor/high consumption customers would be better off under a phase-in, the majority of customers would be better off under no phase-in to the MGS rate proposals, including the typical customers between the 20th and 80th percentile (by annual consumption and load factor as illustrated by the oval in Figures 6-14 and 6-15 on page 6-68 of Exhibit B-1). These facts, when combined with the complexity of implementing a phase-in that would be difficult for customers to understand, and would make bills difficult to predict, led BC Hydro to propose no phase-in for the MGS class. There were no explicit weights used to arrive at this position.**

83.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, pp. 6-62, 6-65, 6-66 and Table 6-20 Large General Service rate

On page 6-62, BC Hydro states "Increasing the level of demand-cost recovery through the flat demand charge from ~50 per cent to 65 per cent will improve fairness in cost allocation and will further offset the impacts of energy rate flattening and dampen the range of bill impact variation among LGS customers across size and load factor."

On page 6-65, BC Hydro states "The larger consuming customers tend to have minimal impacts during the transition, while the low load factor, and low consumption tend to see the biggest impacts due to charges on the first 35 kW of demand."

And on page 6-66, it says that "AMPC argues that the LGS Demand Sensitivity outcome is not acceptable given that high load factor customers make more efficient use of BC Hydro's system."

1.83.1 Table 6-20 indicates that the 50 percent demand cost recovery sensitivity only increases the flat energy rate from 5.37 cents/ kWh to 5.98 cents / kWh. Since the energy rate remains well below LRMC, is it BC Hydro's view that either energy rate will attract similar levels of rate induced natural conservation?

RESPONSE:

Yes. Natural conservation is defined as "conservation induced by RRA rate increases absent any rate structure changes", and is not impacted by the proposed changes in rate structure (Exhibit B-1, page 5-16, footnote 18). Natural conservation is the same for both the proposed and sensitivity LGS scenarios.

83.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.4.4.2 Large General Service, pp. 6-62, 6-65, 6-66 and Table 6-20 Large General Service rate

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On page 6-65, BC Hydro states "The larger consuming customers tend to have minimal impacts during the transition, while the low load factor, and low consumption tend to see the biggest impacts due to charges on the first 35 kW of demand."

And on page 6-66, it says that "AMPC argues that the LGS Demand Sensitivity outcome is not acceptable given that high load factor customers make more efficient use of BC Hydro's system."

1.83.2 The bill impact analysis undertaken by BC Hydro on pages 6-64 and 6-65 seems to indicate that maintaining the status quo 50 percent demand cost recovery has less impact on customer bills. Why then does BC Hydro prefer the 65 percent demand cost recovery? Is BC Hydro giving preference to the rate design objective of economic cost recovery over bill impacts? Please explain BC Hydro's analysis.

RESPONSE:

As Exhibit B-1, page 6-46 and page 6-65 have discussed, the absolute range of bill impact is similar between the proposed and sensitivity designs. However, comparing Exhibit B-1 Figure 6-12 (Proposed) and Exhibit B-1 Figure 6-13 (Sensitivity), the proposed design offers more fair bill impact distribution across different load factors. For instance, at 1,000,000 kWh, the bill impacts less RRA ranges from about 0 per cent to 2.4 per cent under the Proposed design (Exhibit B-1, Figure 6-12), compared to the Sensitivity design, which has a much larger range of about -14.3 per cent to 4.6 per cent. The Proposed design also has lower bill impacts than the Sensitivity design for high load factor customers, including those with high consumption as AMPC observed (refer to page 6-66 of Exhibit B-1).

As stated from Exhibit B-1, pages 6-59 to page 6-62, in the context of testing demand charge cost recovery levels, BC Hydro prioritized two Bonbright criteria: customer understanding (bill impacts) and fairness. Economic efficiency was not a major consideration given the minor reduction in the flat energy rate.

84.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.6 General Service, pp. 6-70 and 6-71
New Accounts in 2016

BC Hydro requests a final order effective January 1, 2016 approving a change in the pricing for new accounts that do not have a HBL on RS 15xx or RS 16xx from 85 per cent of monthly consumption billed at the Part 1 energy rate and 15 per cent of monthly consumption at the Part 2 energy rate (85/15 Pricing) to 100 per cent of the monthly consumption billed at the Part 1 energy rate (100 per cent Part 1 Pricing).

1.84.1 To the best of BC Hydro's knowledge, what is the likely number of new customers that will be impacted? Will any new customers in 2016 suffer harm if the requested order is not issued, effective January 1, 2016? If BC Hydro is not able to quantify the impact for 2016, please provide the number of impacted customers in the past three years F13, F14, and F15.

RESPONSE:

The following table indicates the number of customers impacted by the 85/15 new account pricing rule:

Fiscal Year	MGS	LGS
F2013	**274**	**414**
F2014	**2,348**	**595**
F2015	**1,664**	**594**
F2016 (to September 2015)	**867**	**235**

If the 85/15 pricing cannot be changed prior to the end of F2016, BC Hydro estimates there will be approximately 170 more LGS accounts and 620 more MGS accounts impacted in F2016.

There will be approximately 490 more LGS accounts and 1,850 more MGS accounts impacted in F2017 if the rule is not changed until the end of F2017.

84.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.6 General Service, pp. 6-70 and 6-71
New Accounts in 2016

BC Hydro requests a final order effective January 1, 2016 approving a change in the pricing for new accounts that do not have a HBL on RS 15xx or RS 16xx from 85 per cent of monthly consumption billed at the Part 1 energy rate and 15 per cent of monthly consumption at the Part 2 energy rate (85/15 Pricing) to 100 per cent of the monthly consumption billed at the Part 1 energy rate (100 per cent Part 1 Pricing).

1.84.2 If the flat MGS and/or flat LGS energy proposals of BC Hydro are not approved after this RDA, whereas, a separate approval is granted for the amendment to the 85/15 pricing of new accounts, how does BC Hydro plan to address the issue of fairness in exposing all other customers to the LRMC. Please discuss.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.78.2.

85.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Sections 6.8 General Service, p. 6-74 RS 1253

BC Hydro did not specifically discuss RS 1253 with stakeholders. However, as set out in section 7.4.2 of the Application, RS 1853 - which is available to IPP customers served at transmission voltage for forced outages, scheduled maintenance requirements and black-start re-energization of generators, and has identical energy rate pricing and monthly minimum charge was discussed at Workshops 5 and 10. The only issue identified concerning RS 1853 is whether the non-firm energy rate pricing should be aligned with another non-firm rate, RS 1880 – like RS 1253, RS 1853 is based on Mid-C market prices whereas RS 1880 is set to the prevailing RS 1823 Tier 2 rate. At Workshop 10, BC Hydro provided its view that non-firm energy sold to IPPs should be priced off the Mid-C market because non-firm energy acquired from IPPs is typically priced at Mid-C, thus ensuring that non-firm energy is consistently valued whether it flows from BC Hydro to the IPP customer or from the IPP service provider to BC Hydro.

1.85.1 For consistency between RS 1253 and RS 1853, is it BC Hydro's view that whichever pricing is set for RS 1853, the same pricing should apply to RS 1253? If not, please explain.

RESPONSE:

Yes, BC Hydro's view is that the same pricing should apply to both RS 1253 and RS 1853.

86.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application Volume 4 of 5, Appendix C4, Evaluation of the Large and Medium General Service Conservation Rates, F2014, p. 15
Control group

BC Hydro randomly selected and assigned 400 accounts to a control group in 2010 before the implementation of new conservation rates, with 200 drawn from the MGS population and 200 drawn from the LGS population.

1.86.1 Please describe how it was determined that 400 control accounts would provide a good level of precision in evaluating energy savings due to the LGS and MGS conservation rates.

RESPONSE:

Prior to submitting the 2009 LGS Application, BC Hydro analyzed historical energy usage and demand charge information of general service customers with billing demand of greater than 35 kW (the former LGS rate class prior to segmentation) to determine the optimal size of a control group. The analysis used a Model Based Stratified Sampling Design approach with a target 10 per cent relative precision at a 90 per cent confidence level. The analysis suggested that 400 control accounts would be adequate for future evaluation efforts of the former LGS rate class prior to segmentation.

87.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application Volume 4 of 5, Appendix C4, Evaluation of the Large and Medium General Service Conservation Rates, F2014, p. 28
Customer awareness, understanding and acceptance of the conservation rates

Customer surveys, customer focus groups and key account manager interviews were used to collect information related to customer awareness, understanding and acceptance of the MGS and LGS rates.

1.87.1 Would BC Hydro confirm that the survey results show that there is a higher percentage of customers who strongly support the rate (9 percent and 21 percent) than customers who strongly oppose the rate (5 percent to 7 percent)? If confirmed, what are the implications of this finding to BC Hydro's proposed rate structure?

RESPONSE:

Confirmed.

The customer surveys were one of the tools used to solicit feedback from customers on the MGS and LGS rate structures. As described in section 2.2.3 of Exhibit B-1 BC Hydro also held focus groups, topic specific workshops and face-to-face meetings. Taking all input into consideration BC Hydro concluded that the rates were not well supported by customers, were poorly understood and did not result in the expected conservation. This information helped inform BC Hydro's proposed MGS and LGS flat rates.

87.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application Volume 4 of 5, Appendix C4, Evaluation of the Large and Medium General Service Conservation Rates, F2014, p. 28
Customer awareness, understanding and acceptance of the conservation rates

Customer surveys, customer focus groups and key account manager interviews were used to collect information related to customer awareness, understanding and acceptance of the MGS and LGS rates.

1.87.2 Is it true that it is the mechanics of the rate that cause the most complaints from focus group participants and key account customers? If so, does it imply that some form of simplified conservation rate structure may still be desirable? Could educational initiatives overcome the complaints regarding rate complexity and thereby lead to improved conservation?

RESPONSE:

Most focus group participants and key account customers complained about the mechanics of the rate. Please refer to Exhibit B-1, Appendix C-4A, page 424 of 813.

While customer complaints about the rates' complexity could imply that some form of simplified rate structure may be desirable, BC Hydro determined that an inclining block rate alternative would not be viable for the diverse MGS or LGS classes, as described in sections 6.3.4.2 and 6.4.4.2 of Exhibit B-1 and in BC Hydro's response to BCUC IR 1.56.1.1.

Evidence from the focus groups indicated that educational initiatives may have limited effectiveness. Focus group participants, who were decision makers regarding energy at LGS and MGS sites, demonstrated key gaps in understanding about how to use the rate as a tool to manage their energy bill through changes in consumption, even after video and moderator explanation. Please refer to the Qualitative Research Report forming part of the F2014 LGS and MGS Evaluation Report found at Exhibit B-1, Appendix C-4A, page 534 of 813.

88.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application Volume 4 of 5, Appendix C4, Evaluation of the Large and Medium General Service Conservation Rates, F2014, p. 29
Customer response to conservation rates

Customer surveys, customer focus groups and key account manager interviews were used to collect information related to customer awareness, understanding and acceptance of the MGS and LGS rates.

1.88.1 Would BC Hydro confirm that among those customers who could identify the energy charge component of their rate unaided, more customers indicated that the rate served as a major incentive to conserve (41 percent) versus those who indicated that it served as no incentive at all (35 percent)? If confirmed, does BC Hydro believe that the status quo MGS and LGS rate design offers some form of conservation incentives?

RESPONSE:

Confirmed.

BC Hydro believes the status quo MGS and LGS rate designs had a modest incentive effect. Please refer to Exhibit B-1, Appendix C-4A, page 427 of 813.

89.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application Volume 4 of 5, Appendix C4, Evaluation of the Large and Medium General Service Conservation Rates, F2014, pp. 38, 39
Methodology to estimate energy and peak demand savings

In relation to the estimate of energy savings from the LGS conservation rate, the report shows the evaluated savings of 77 GWh/year at 85 percent confidence level for F2014.

The prior evaluation estimated net evaluated energy savings were 144 GWh/year by the end of 2011 and 200 GWh/year by the end of 2012. Moreover the Evaluation Report shows that energy savings estimates for 2011 and 2012 were statistically significant at the 90 percent confidence level.

1.89.1 Has any work been done to understand the drop in energy savings in F2014? If so, please provide the reference in the Evaluation Report. If no, please explain why not.

RESPONSE:

The F2014 LGS and MGS Evaluation Report provided evidence that awareness and demonstrated understanding of the of the two part MGS and LGS rates was low. Please refer to Exhibit B-1, Appendix C-4A, page 424 of 813. BC Hydro believes that this low awareness and low demonstrated understanding created a barrier to business customers investing in capital projects to reduce electricity consumption.

The Evaluation further demonstrated that savings declined from 2012 to F2014 and became less certain. Please refer to Exhibit B-1, Appendix C-4A, page 437 of 813. This savings profile is characteristic of operational, maintenance and behaviour energy conservation measures that customers allow to lapse.

The development and implementation of a research project to examine and definitively explain the drop in energy savings would be resource intensive and may not yield conclusive or actionable results.

89.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application Volume 4 of 5, Appendix C4, Evaluation of the Large and Medium General Service Conservation Rates, F2014, pp. 38, 39
Methodology to estimate energy and peak demand savings

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The prior evaluation estimated net evaluated energy savings were 144 GWh/year by the end of 2011 and 200 GWh/year by the end of 2012. Moreover the Evaluation Report shows that energy savings estimates for 2011 and 2012 were statistically significant at the 90 percent confidence level.

1.89.2 It is stated in the Evaluation Report that the 77 GWh/year savings are cumulative since the implementation of the conservation rates, and cannot be added to savings from 2012 and 2011. Does this statement imply that savings measured in earlier years failed to persist?

RESPONSE:

Savings are estimated on a cumulative run rate basis, which means that if savings from calendar year 2011 persist to F2014 then they are included in the evaluated F2014 savings. The evaluation method cannot delineate between F2014 savings that started in earlier years and F2014 savings that started in F2014.

Please also refer to BC Hydro's response to BCUC IR 1.89.1.

89.0 E. CHAPTER 6 – GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Application Volume 4 of 5, Appendix C4, Evaluation of the Large and Medium General Service Conservation Rates, F2014, pp. 38, 39
Methodology to estimate energy and peak demand savings

In relation to the estimate of energy savings from the LGS conservation rate, the report shows the evaluated savings of 77 GWh/year at 85 percent confidence level for F2014.

The prior evaluation estimated net evaluated energy savings were 144 GWh/year by the end of 2011 and 200 GWh/year by the end of 2012. Moreover the Evaluation Report shows that energy savings estimates for 2011 and 2012 were statistically significant at the 90 percent confidence level.

1.89.3 It is described in the Evaluation Report that the influence of parallel DSM initiatives is controlled for in the randomized control trial research design (page 24 of the Evaluation Report). In BC Hydro's view, is it likely that by the third year after the implementation, LGS and MGS customers have chosen to take up DSM initiatives for conservation as a result of the MGS and LGS conservation rates?

RESPONSE:

No statistically significant influence of LGS/MGS two-part rates on customer participation in DSM initiatives had been perceived by the end of F2014.

DSM program participation rates of treatment and control accounts were compared during calendar years 2011 and 2012 and during F2014 (refer to Exhibit B-1, Appendix C-4A, pages 663 to 664 of 813 and pages 464 to 465 of 813). Statistical tests showed that treatment group participation rates in DSM programs were not statistically significantly different from those of control groups.

90.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.2 Transmission Service, p. 7-5, Table 7-1
RS 1823

BC Hydro shows that the average existing RS 1823 energy rate A is low compared to LRMC and that the Tier 1 rate is very low at 3.836 cents/kWh. The energy rate A is a flat rate at 4.303 cents/kWh for new accounts.

1.90.1 Please provide a summary of the competing rate design objectives and legislative constraints as they impact the Tier 1 and Tier 2 pricing. For example, does BC Hydro feel constrained in keeping the Tier 2 price at the low end of LRMC because the Tier 1 price is already so low? Could the Demand charge be reduced to the LGS 50 percent cost recovery to allow for a higher Tier 2 price?

RESPONSE:

The competing rate design objectives as they impact RS 1823 Tier 1 and Tier 2 pricing include:

- **Efficiency (through Tier 2 price signal);**
- **Fairness;**
- **Rate and bill stability;**
- **Recovery of revenue requirement (relates to revenue neutrality definition); and**
- **Customer understanding and acceptance.**

Section 7.2.1 of Exhibit B-1 summarizes the legislative constraints on the Commission in designing RS 1823 Tier 1 and Tier 2 rates for BC Hydro's Transmission Service customers. RS 1823 must adhere to the following:

- **The Tier 2 rate should reflect BC Hydro's energy LRMC;**
- **The quantity of Tier 1 power sold to Transmission Service customers should be set at 90 per cent, and the Tier 2 quantity should make up the remaining 10 per cent; and**

- **The Tier 1 rate should be derived from the Tier 2 rate and the Tier 1/Tier 2 90/10 split to achieve, to the extent reasonably possible, revenue neutrality.**

Section 7.2.1 of Exhibit B-1 also provides BC Hydro's view as to the Commission's jurisdiction over the three RS 1823 elements under sections 58 to 61 of the *UCA,* namely: (i) setting pricing principles for F2017 to F2019 as long as Tier 2 remains within BC Hydro's energy LRMC range; (ii) definition of revenue (customer bill) neutrality; and (iii) demand charge.

Regarding the constraints in setting the Tier 2 price, in F2017 the Tier 2 price must be increased by more than the RRA increase for the Tier 2 price to reflect BC Hydro's energy LRMC. In section 7.2.2.1 of Exhibit B-1, BC Hydro provides the rationale for setting the Tier 2 price at the low end of BC Hydro's energy LRMC in F2017 under its preferred Option 1 i.e., it allows RRA increases in F2018 and F2019 to meet all requirements of Direction No. 7 (LRMC-based Tier 2, revenue neutral under either definition, Tier 1 rate calculated residually).

If BC Hydro were to set the Tier 2 price at a higher level in F2017, this would imply that the Tier 1 price would be at a lower level than otherwise under bill neutrality. This would result in a greater revenue shortfall, given forecast Tier 1 and Tier 2 consumption. This was Option 3, which was rejected by BC Hydro and stakeholders as part of Workshop 10; refer to section 1.2.1 of the Workshop 10 consideration memo at Exhibit B-1, Appendix C-5B, pages 62-63 of 212.

Finally, it is possible to reduce the demand charge to 50 per cent recovery and to increase the Tier 2 price. However, BC Hydro's view is that the current demand charge, which recovers 65 per cent of demand-related costs, is appropriate, as explained in sections 7.2.4.1 and 7.2.4.2 of Exhibit B-1. The proposed RS 1823 pricing under Option 1 also meets the requirement that the Tier 2 price remains within BC Hydro's energy LRMC.

90.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.2 Transmission Service, p. 7-5, Table 7-1
RS 1823

BC Hydro shows that the average existing RS 1823 energy rate A is low compared to LRMC and that the Tier 1 rate is very low at 3.836 cents/kWh. The energy rate A is a flat rate at 4.303 cents/kWh for new accounts.

1.90.2 Is BC Hydro concerned that the new accounts that do not have CBLs will not get adequately exposed to the LRMC by taking service at the energy A flat rate in the first year?

RESPONSE:

BC Hydro is not concerned with this, since the lack of exposure to LRMC by new accounts is only in the first year. This has little impact on conservation, given that the first year load of new accounts is relatively a small proportion of class load.

90.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.2 Transmission Service, p. 7-5, Table 7-1
RS 1823

BC Hydro shows that the average existing RS 1823 energy rate A is low compared to LRMC and that the Tier 1 rate is very low at 3.836 cents/kWh. The energy rate A is a flat rate at 4.303 cents/kWh for new accounts.

1.90.3 Please compare and contrast this RS 1823 A flat rate with the flat rate proposed for the LGS MGS New Account Rule where 100 percent of the monthly consumption will be billed at the Part 1 energy rate.

RESPONSE:

The table below compares the pricing for RS 1823 Energy Rate A with the proposed 100 per cent Part 1 pricing for new accounts for MGS and LGS.

	F2016 Rates
RS 1823 Energy Rate A	**4.303 cents/kWh**
Existing MGS RS 15xx **First 14,800 kWh – Tier 1 Rate** **All additional kWh – Tier 2 Rate**	 **9.89 cents/kWh** **6.90 cents/kWh**
Existing LGS RS 16xx **First 14,800 kWh – Tier 1 Rate** **All additional kWh – Tier 2 Rate**	 **10.66 cents/kWh** **5.13 cents/kWh**

91.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.2 Transmission Service, pp. 7-7, 7-12 and 7-13
Defining "revenue neutrality"

On page 7-7, BC Hydro states that the Commission has jurisdiction over the "Definition of revenue (customer bill) neutrality, which differs from the forecast revenue neutral approach used for the Residential and SGS/MGS/LGS rate classes. The term "revenue neutrality" used in Recommendation #8 is not defined, and could be either customer bill neutrality or forecast revenue neutrality."

On page 7-12, it states that:

BC Hydro is not seeking any order regarding the general application of a revenue neutrality definition. BC Hydro is proposing pricing principles for three years (Option 1) that in all three years achieves customer bill neutrality; in two of the three years also achieves forecast revenue neutrality; and in the one-year it doesn't achieve forecast revenue neutrality (F2017), Tier 2 is within the energy LRMC range in accordance with the first element of Recommendation #8. The result is an approach that yields RS 1823 pricing that in F2018 and F2019 satisfies all of the requirements of Recommendation #8.

On page 7-13, it states "BC Hydro favours the customer bill neutrality approach to determine RS 1823 rates in F2017 so that the Tier 2 rate is set at the lower range of LRMC."

1.91.1 Please explain why BC Hydro does not seek a Commission determination of the definition of revenue neutrality? Would such a determination provide some certainty for future rate settings and RDAs? E.g., the design of X-LGS rate in module 2?

RESPONSE:

BC Hydro's view is that a Commission determination of definition of revenue neutrality in the context of RS 1823 may reduce the flexibility that BC Hydro has in pricing RS 1823 energy rates given the Direction No. 7 and other legislative constraints. BC Hydro's preferred Option 1 pricing uses customer bill neutrality in F2017 and both customer bill neutrality and forecast revenue neutrality in F2018 and F2019. Customer bill neutrality in F2017 has the advantage of maintaining the price differential between Tier 2 and Tier 1 the same while keeping Tier 2 in the LRMC range.

The term "revenue neutrality" used in Heritage Contract Report Recommendation No. 8 is not defined, and could be either customer bill neutrality or forecast revenue neutrality. Customer bill neutrality is unique to RS 1823 and was agreed to by all stakeholders under the terms of the NSA for BC Hydro's TSR Application filed in March 2005. It was also used in pricing RS 1823 energy rates in BC Hydro's TSR Re-pricing Application (February 2008) which was approved by the Commission.

Forecast revenue neutrality was used to determine RS 1823 energy rates under Direction No. 6. RRA increases were applied to both RS 1823 Tier 1 and Tier 2 energy rates for F2015 and F2016. This methodology is easily understood and consistent with how RRA increases have been applied to other rates.

A Commission determination regarding revenue neutrality may provide certainty regarding future rate designs, but may limit feasible rate options. BC Hydro's view is that each rate design should be examined on its own merits, including assumptions regarding revenue neutrality. In this way, trade-offs using rate design evaluation criteria can be made. This is the approach that has been used in previous BC Hydro rate design filings.

92.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.2.2.2 Transmission Service, pp. 7-10, 7-12 and 7-13
RS 1823 Option 3 pricing

Option 3: In F2017, all of the RRA rate increase is applied to Tier 2 and Tier 1 is held constant at its F2016 level. For F2018, applying all of the RRA rate increase to Tier 2 results in Tier 2 being above the upper end of the LRMC range. As a result, Tier 2 is capped at the upper end of the LRMC range, and Tier 1 is adjusted accordingly. For F2019, both Tier 1 and Tier 2 are calculated as in F2018. Option 3 is not forecast revenue neutral. Option 3 reflects the prioritization of the Bonbright efficiency criterion by increasing Tier 2 to the upper end of the energy LRMC range." And "No stakeholder supports Option 3." And "Option 3 under-recovers revenue by $8.8 million, $12.0 million and $11.7 million for F2017, F2018 and F2019 respectively.

1.92.1 In your response, please provide Recommendation #8 of the Heritage Contract Report. Is Option 3 consistent with the intent of Recommendation 8? Why?

RESPONSE:

Recommendation No. 8 of the Heritage Contract Report states:

> **That stepped rates be implemented according to the principles and considerations set forth in Chapter 3 [of the Heritage Contract Report]. The principles are repeated below for convenience:**
>
> **The Tier 2 rate should reflect the long-term opportunity cost of new supply, where long-term is understood to include the acquisition cost required to obtain that supply;**
>
> **The quantity of power being sold to industrial customers at Tier 1 of the stepped rate should be initially set at 90 per cent, and the Tier 2 quantity should make up the remaining 10 per cent; and**
>
> **The Tier 1 rate should be derived from the Tier 2 rate and the Tier 1/Tier 2 [90/10 split] to achieve, to the extent reasonably possible, revenue neutrality.**

Option 3 is consistent with the Recommendation #8 principles that Tier 2 reflect the long-term opportunity cost of new supply and that Tier 1 rate should be derived from the Tier 2 rate and the Tier 1/Tier 2 split to achieve, to the extent reasonably possible, revenue neutrality. Under Option 3, in F2018 and F2019 the Tier 2 rate was set at the upper end of the LRMC range and the Tier 1 rate was set residually assuming customer bill neutrality.

92.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.2.2.2 Transmission Service, pp. 7-10, 7-12 and 7-13
RS 1823 Option 3 pricing

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1.92.2 With no stakeholder support and under-recovery of allocated revenue requirement considerably higher than Options 1 or 2, why did BC Hydro carry Option 3 forward for consideration in this RDA?

RESPONSE:

As discussed on pages 62 and 65 of 212 of Workshop 10 consideration memo found at Appendix C-5B of Exhibit B-1, BC Hydro carried Option 3 forward in response to Catalyst's suggestion that Option 3 could be beneficial to customers who reduce their RS 1823 Tier 2 consumption through conservation measures.

93.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.2.3.1 Transmission Service, p. 7-13 and Table 7-3
RS 1823 Options 1 and 2 pricing

On page 7-13, the Application shows that Option 1 under recovers revenue in F2017 by $2.2 million, and Option 2 under-recovers revenue by $2.2 million, $1.4 million and $0.9 million for F2017, F2018 and F2019 respectively.

1.93.1 Although BC Hydro favours Option 1 pricing, would it agree that the price differences between Options 1 and 2 are very small and that an advantage of Option 2 is to keep Tier 1 rates slightly above Option 1's Tier 1 rates in F2018 and F2019?

RESPONSE:

BC Hydro does not agree. BC Hydro's basis for preferring Option 1 over Option 2 is that Option 2 diminishes the signal to conserve because over time the Tier 1 and Tier 2 differential will decrease, since the Tier 2 price under Option 2 does not increase as much as under Option 1. There is also no advantage to the Option 2 Tier 1 price since it is almost the same as the Option 1 Tier 1 price.

94.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.2.3.2 Transmission Service, p. 7-14
RS 1823 Option 1 customer bill neutrality

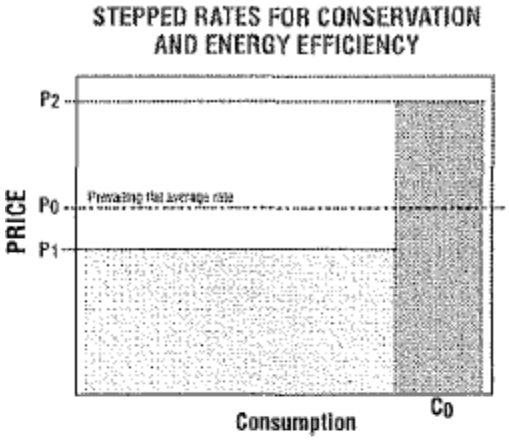
"The customer bill neutrality definition aligns with Policy Action No. 21 of the 2002 Energy Plan..."

1.94.1 Please provide Policy Action No. 21 in your response. Please explain why BC Hydro believes that bill neutrality aligns with Policy Action 21 and why revenue neutrality does not?

RESPONSE:

The following provides the relevant excerpt from Policy Action No. 21:

> **Policy Action #21 (new): New rate structures will provide better price signals to large electricity consumers for conservation and energy efficiency.**
>
> **The BC Utilities Commission will conduct a hearing to develop new stepped and time-of-use pricing for BC Hydro's industrial and large commercial customers. As a principle, for stepped rates, the last block of energy consumed should reflect the cost of new supply. This will encourage these customers to meet part of their electricity needs through conservation and energy efficiency, or from other sources (self-generation or IPP purchases), where they can do so cost-effectively.**
>
> **To keep rates low overall, the stepped rate structure will be revenue-neutral (see box):**



Stepped Rates for Conservation and Energy Efficiency

A revenue-neutral two-step electricity rate charges less for the first block of electricity consumed (P_1), and more for the second block (P_2), relative to the prevailing flat average rate (P_0). At the higher price P_2, the consumer has a greater incentive to cut back on electricity use, or to invest in cost-effective energy efficiency for that portion of consumption. At the existing consumption level C_0, the total cost to the consumer and the total revenue to the distribution company offering the rate are unchanged.

Revenue neutrality is achieved under Policy Action No. 21 if the total cost to the customer and the total revenue to BC Hydro are the same under the stepped rate as under the flat rate at the customer's existing consumption level. Under this definition, RS 1823 is intended to cause no change in a customer's annual bill, provided the customer continues to consume at its existing (CBL) consumption level. Therefore under F2017 Option 1 pricing, 90 per cent of the CBL priced at the Tier 1 price plus 10 per cent of the CBL priced at the Tier 2 price produces the same revenue as the total CBL priced at the flat rate (RS 1823 energy rate A). This

pricing when applied to forecast F2017 consumption results in a $2.2 million revenue shortfall. If forecast revenue neutrality was applied by raising the Tier 1 price to recover the shortfall in revenue, customer bill neutrality would no longer be achieved since a customer consuming at its CBL will no longer pay the same bill as under the flat rate.

95.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.2.3.1 Bill Neutrality, pp. 7-12 to 7-14
BC Hydro proposal and stakeholder engagement

On page 7-14 of the Application, BC Hydro describes AMPC's position that the adoption of the forecast revenue neutrality approach is unacceptable to customers taking service under RS 1823 as it unfairly results in impacts to customers that have successfully conserved energy in response to the Tier 2 rate price signal. On the same page, BC Hydro also describes that the non-Transmission Service customer participants favour using the forecast revenue neutrality approach to ensure consistency with other classes.

BC Hydro uses the revenue-cost ratios from the F2014 FACOS and F2016 FACOS to indicate that the Transmission Service Rate class is not being subsidized by other rate classes.

1.95.1 Why is BC Hydro relying on the TSR R/C ratio as an argument to support bill neutrality? Shouldn't the merits of bill neutrality pricing and forecast revenue neutrality pricing be focused on revenue allocation as opposed to cost allocation?

RESPONSE:

The Transmission Service R/C ratio provides an indicator as to whether the Transmission Service revenue under F2014 and F2016 rates covers costs. The F2014 and F2016 Transmission Service rates were derived under bill neutrality, so the results do provide evidence that revenue covered costs in that year.

95.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.2.3.1 Bill Neutrality, pp. 7-12 to 7-14
BC Hydro proposal and stakeholder engagement

On page 7-14 of the Application, BC Hydro describes AMPC's position that the adoption of the forecast revenue neutrality approach is unacceptable to customers taking service under RS 1823 as it unfairly results in impacts to customers that have successfully conserved energy in response to the Tier 2 rate price signal. On the same page, BC Hydro also describes that the non-Transmission Service customer participants favour using the forecast revenue neutrality approach to ensure consistency with other classes.

BC Hydro uses the revenue-cost ratios from the F2014 FACOS and F2016 FACOS to indicate that the Transmission Service Rate class is not being subsidized by other rate classes.

1.95.2 Please confirm that the merits of whether a bill neutrality definition approach continues to be appropriate are influenced by BC Hydro's under-recovery of forecast revenue from the TSR class since the stepped rate's implementation.

RESPONSE:

Not confirmed.

BC Hydro's view is that the forecast revenue in the F2017 to F2019 period is most relevant in assessing the merits of the bill neutrality definition approach. The F2017 to F2019 forecast revenue for the three pricing options has been updated in BC Hydro's response to BCOAPO IR 1.160.4.

Please also refer to BC Hydro's response to BCUC IR 1.91.1.

95.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.2.3.1 Bill Neutrality, pp. 7-12 to 7-14
BC Hydro proposal and stakeholder engagement

On page 7-14 of the Application, BC Hydro describes AMPC's position that the adoption of the forecast revenue neutrality approach is unacceptable to customers taking service under RS 1823 as it unfairly results in impacts to customers that have successfully conserved energy in response to the Tier 2 rate price signal. On the same page, BC Hydro also describes that the non-Transmission Service customer participants favour using the forecast revenue neutrality approach to ensure consistency with other classes.

BC Hydro uses the revenue-cost ratios from the F2014 FACOS and F2016 FACOS to indicate that the Transmission Service Rate class is not being subsidized by other rate classes.

1.95.3 BC Hydro describes AMPC's position that the forecast revenue neutrality approach unfairly results in impacts to customers that have successfully conserved energy in response to the Tier 2 rate price signal. Is BC Hydro able to provide an example of how this occurs?

RESPONSE:

The table below shows a simple example of how a customer conserving energy under DSM would pay more under F2017 rates using the forecast revenue neutrality approach compared to F2017 rates using the bill neutrality approach.

	F2017
F2016 Consumption MWh	**100**
CBL MWh	**100**
DSM MWh	**5**
Consumption MWh	**95**
Tier 1 Load MWh	**90**
Tier 2 Load MWh	**5**
Bill Neutrality (Option 1 Table 7-3 Exhibit B-1)	
Tier 1 ($/MWh)	**39.81**
Tier 2 ($/MWh)	**89.2**
Forecast Revenue Neutrality (Option 1 BC Hydro response to BCOAPO IR 1.160.7)	
Tier 1 ($/MWh)	**39.86**
Tier 2 ($/MWh)	**89.2**
Customer Bill under Bill Neutrality ($000)	**4028.9**
Customer Bill under Forecast Revenue Neutrality ($000)	**4033.4**

96.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.2.4.2 Transmission Service, p. 7-16
RS 1823 demand charges

"The amount of demand-related costs the demand charge is recovering, at approximately 65 per cent of demand-related costs identified in the F2016 COS study, is appropriate."

1.96.1 BC Hydro identifies that a higher level of demand cost recovery would drive the Tier 2 price below LRMC. Please also provide BC Hydro's reasons for not considering a decrease in demand cost recovery to maintain a higher Tier 2 price.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.90.1.

96.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.2.4.2 Transmission Service, p. 7-16
RS 1823 demand charges

"The amount of demand-related costs the demand charge is recovering, at approximately 65 per cent of demand-related costs identified in the F2016 COS study, is appropriate."

1.96.2 What are the comparable Canadian electric utilities transmission class demand cost recovery percentages?

RESPONSE:

BC Hydro obtained the following transmission class demand charge demand-related cost recovery percentages for comparable Canadian utilities (based on having significant hydro generation):

- **Hydro Quebec – 100 per cent (last estimated in 2004);**
- **Manitoba Hydro – 163 per cent (for General Service Large > 100 kV class); and**
- **Newfoundland Hydro – 109 per cent.**

97.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.1 Transmission Service, pp. 7-19, 7-20 and 7-21
RS 1825

On page 7-19, BC Hydro states "Since its implementation on April 1, 2006, no Transmission Service customer has taken service under RS 1825."

On page 7-20, "BC Hydro stated that, in its view, it is not possible to design an optional cost-based TOU rate that provides sufficient price differentials and/or offers Transmission Service customers more benefits than RS 1823…" And "AMPC reasoned that overall complexity, low margins, price risk and the current three-year commitment requirement combine to make RS 1825 less attractive to Transmission Service customers than RS 1823."

On page 7-21"… in BC Hydro's view it is unlikely that there can be a significant enough difference between on-peak and off-peak rates to encourage a change in consumption patterns."

1.97.1 Should RS 1825 be terminated if it cannot be reconfigured to be successful? Why?

RESPONSE:

There may be a legal issue associated with terminating RS 1825, because Heritage Contract Report Recommendation No. 13 provided that TOU rates should be implemented at the same time as the Transmission Service stepped rate (RS 1823), and subsection 3(1) of Direction No. 7 requires the Commission to ensure that rates for BC Hydro's Transmission Service customers are consistent with Heritage Contact Recommendations No. 8 to No. 15 inclusive. In other words, it may be that the Commission cannot unilaterally terminate RS 1825 given the wording of Heritage Contract Report Recommendation No. 13.

In any event, keeping RS 1825 open has no cost to BC Hydro or its customers.

97.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.1 Transmission Service, pp. 7-19, 7-20 and 7-21
RS 1825

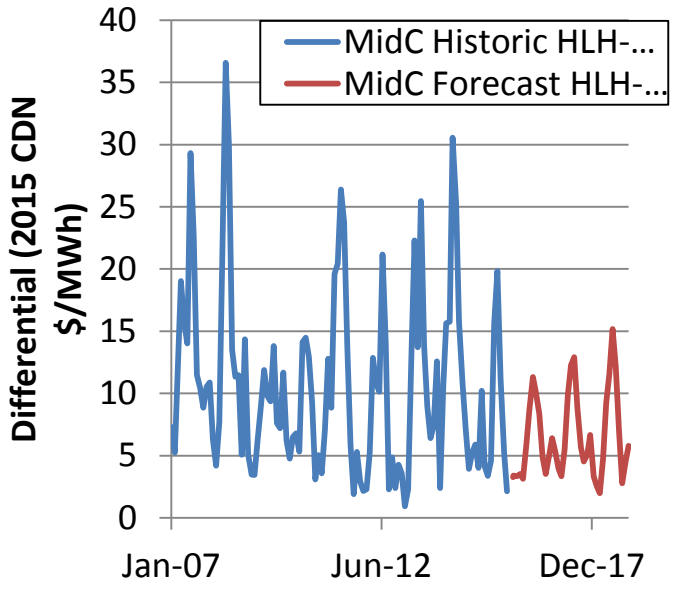
On page 7-19, BC Hydro states "Since its implementation on April 1, 2006, no Transmission Service customer has taken service under RS 1825."
On page 7-20, "BC Hydro stated that, in its view, it is not possible to design an optional cost-based TOU rate that provides sufficient price differentials and/or offers Transmission Service customers more benefits than RS 1823…" And "AMPC reasoned that overall complexity, low margins, price risk and the current three-year commitment requirement combine to make RS 1825 less attractive to Transmission Service customers than RS 1823."
On page 7-21"… in BC Hydro's view it is unlikely that there can be a significant enough difference between on-peak and off-peak rates to encourage a change in consumption patterns."

1.97.2 Are the current and forecast very low natural gas commodity prices likely to ensure that the differentials between on and off peak rates remain inadequate to attract customers to RS 1825?

RESPONSE:

Yes. Forecast Mid C differentials between HLH and LLH periods, for 2016 to 2018 on a monthly basis, are in the range of CDN $2/MWh to CDN $15/MWh, with an average differential of CDN $6.50/MWh.

Between 2007 and 2015, historical differentials averaged CDN $10.5/MWh, as can be seen in the figure below.



98.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.2 Transmission Service, pp. 7-22 & 7-23
RS 1852

BC Hydro proposes a change in the current RS 1852 definition of HLH (06:00 hours to 10:00 hours and 16:00 hours to 20:00 hours, Monday through Friday, except for Statutory holidays), to provide BC Hydro discretion to determine the HLH periods that will apply based on a customer location/region which affords BC Hydro the option to curtail to alleviate potential local or regional transmission constraints or take advantage of a market opportunity.

On pages 6-22 to 6-23, BC Hydro states

Only one Transmission Service customer has taken service under RS 1852 at any one time.

RS 1852 was originally designed around Vancouver Island's unique two peak system load (6 a.m. to 10 a.m. and 4 p.m. to 8 p.m.). However, as demonstrated in section 4.2 of the Consideration Memo, the South Peace region does not have a two peak system load. Areas that may be transmission constrained in the future include the Lower Mainland (depending on the number of LNG proposals that proceed) and the North Coast/Prince Rupert region."

RS 1852 is complex and best suited for customers with large, discrete load centres, load control systems, and product storage or ability to 'make up' lost production". BC Hydro is also proposing to amend the definition of Availability in RS 1852.

1.98.1 Which customers have taken service under RS 1852 and what circumstances led to them taking and terminating service?

RESPONSE:

Two customers have taken service under RS 1852 since its approval on September 12, 2000 (Commission Order No. G-82-00). They are:

Owner	Customer/Facility	Beginning	Ending
Catalyst Paper *	**Elk Falls Pulp, Campbell River**	**December 2000**	**December 2005**
Paper Excellence *	**Howe Sound Pulp and Paper, Port Mellon**	**January 2006**	**July 2015**

*** And its predecessor companies.**

The Elk Falls facility was authorized to take service under RS 1852 to alleviate constraints in transmission to Vancouver Island. With respect to Howe Sound, BC Hydro submitted the RS 1852-related agreement to the Commission for approval on December 19, 2005. The Commission approved BC Hydro's acceptance of that agreement pursuant to Commission Order No. G-143-05.

98.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.2 Transmission Service, pp. 7-22 & 7-23
RS 1852

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RS 1852 is complex and best suited for customers with large, discrete load centres, load control systems, and product storage or ability to 'make up' lost production". BC Hydro is also proposing to amend the definition of Availability in RS 1852.

1.98.2 Given the complexity of RS 1852 and the customer requirements to take advantage of the rate, is there a reasonable prospect that it will be used in the future? Are there sufficient benefits to BC Hydro and its other ratepayers to continue the service, or should RS 1852 be discontinued?

RESPONSE:

To better match BC Hydro's specific requirements in various constrained areas, BC Hydro is proposing to have discretion to determine the HLH period(s) that will apply based on customer location/region. This should broaden the applicability of RS 1852 and may help match the rate to a wider range of unique customer situations.

BC Hydro's view is that there are sufficient benefits to continue the service. BC Hydro indicated in section 4.2 of Workshop 10 consideration memo,

Appendix C-5B to Exhibit B-1, that it believes that there is value in maintaining RS 1852 as an option because the rate provides mutual benefits and because it would be consistent with the B.C. Government's response to several 2013 Industrial Electricity Policy Review task force recommendations that "[a] rate design review process will be launched to examine ways to provide industrial customers with more options to reduce their electricity costs".

Please also refer to BC Hydro's response to BCUC IR 1.98.4.

98.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.2 Transmission Service, pp. 7-22 & 7-23
RS 1852

BC Hydro proposes a change in the current RS 1852 definition of HLH (06:00 hours to 10:00 hours and 16:00 hours to 20:00 hours, Monday through Friday, except for Statutory holidays), to provide BC Hydro discretion to determine the HLH periods that will apply based on a customer location/region which affords BC Hydro the option to curtail to alleviate potential local or regional transmission constraints or take advantage of a market opportunity.

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1.98.3 According to BC Hydro, transmission constraints change over time and by location. In order to better understand the system demand issues, please provide a description of the time periods and location transmission constraints since RS 1852 was established and BC Hydro's projected transmission constraint time periods and location in the next five years.

RESPONSE:

As noted in the Workshop 10 consideration memo (Exhibit B-1, Appendix C-5B, page 103 of 212) RS 1852 came into effect September 2000. At that time Vancouver Island was transmission constrained.

The projects which will remove transmission constraints in BC Hydro's grid between F2014 and F2023 are identified in the 2012 Facilities Study report for the

Network Integration Transmission Service (NITS). These transmission reinforcement projects are driven by the peak hour demand at each region or peak hour flows on transmission paths between regions.

The hours of regional peak demands or transmission path peak flows for the projects in the NITS report are:

1. **Peace Region to Central Interior: Flat path flow in most hours;**

2. **Central Interior to the North Coast: 7:00 a.m. to 11:00 a.m. and 4:30 p.m to 9:30 p.m.;**

3. **Interior to Lower Mainland: Predominantly 4:00 p.m. to 9:00 p.m., Occasionally 7:00 a.m. to 11:00 a.m.;**

4. **Metro North System: 4:00 p.m. to 9:00 p.m.; and**

5. **Dawson Creek and Peace Region: No periodic peaking patterns because of large industrial loads.**

98.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.2 Transmission Service, pp. 7-22 & 7-23
RS 1852

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RS 1852 is complex and best suited for customers with large, discrete load centres, load control systems, and product storage or ability to 'make up' lost production". BC Hydro is also proposing to amend the definition of Availability in RS 1852.

1.98.4 BC Hydro describes the central issue with the RS 1852 is to address the low take-up. Please describe the opportunity lost in terms of value to BC Hydro due to the lack of customers in the past five years.

RESPONSE:

Generally, BC Hydro has had sufficient capacity available over the last five years considering planned system reinforcements to serve customer requests for power. Accordingly, BC Hydro's view is that there has been no opportunity lost in terms of financial value to BC Hydro with respect to relieving short-term constraints.

99.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.3 Transmission Service, p. 7-24 and section 2.4 of Workshop 5 memo Retail access

While the IEPR task force recommended that BC Hydro develop a revised retail access program, the LGIC subsequently issued Direction No. 7; section 14 prevents the Commission from setting rates that result in direct or indirect provision of unbundled transmission service to retail customers in BC Hydro's service area or those who supply such customers, except on application by BC Hydro.

1.99.1 Given the complications identified by BC Hydro to implement a retail access program that would be fair to other customers, what conditions in the future would induce BC Hydro to make a voluntary application for retail access.

RESPONSE:

BC Hydro has no plans to explore retail access in the short to medium term. As discussed during the 2015 RDA stakeholder engagement process, BC Hydro anticipates that the following conditions would need to be in place for BC Hydro to consider pursuing a voluntary retail access program:

- **Sufficient customer and/or third-party interest in a program; and**
- **A fair degree of stakeholder consensus as to the safeguards required to protect non-participating customers.**

100.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.3 Transmission Service, pp. 7-25 & 7-26
Real time pricing

BC Hydro states on pages 7-25 and 7-26 that:

it would be difficult to integrate a stepped rate structure into RTP; the CBL could be priced at the stepped rate, but the marginal price signal would be spot market pricing and not BC Hydro's energy LRMC. The hybrid RTP rate would be asymmetrical if customers receive an energy LRMC price signal for saving energy (i.e., Tier 2 credit) but then receive a market price signal for increasing energy consumption.

1.100.1 Please provide an example to further explain the above quote?

RESPONSE:

As an example, assume that:

- **The customer baseline (CBL) of a hybrid RTP / stepped rate is priced at the blended average of the RS 1823 stepped rate of $43.03/MWh which is also equivalent to the flat energy rate in RS 1823A or RS 1827; and**

- **The hybrid rate is designed such that consumption above the baseline is priced off the Mid C market (assume $35/MWh CDN) while consumption below the baseline receives a credit based off BC Hydro's LRMC (for purposes of responding to this IR a simplified assumption is $85/MWh).**

In this example, there's an asymmetry because increases in load cost the customer $35/MWh while decreases in load are credited at $85/MWh. For such a rate to work, the decreases in load must be firm and result in a decrease in BC Hydro's long run costs while the increases in load must be non-firm and result in no increases in BC Hydro's long run costs. As stated in the Workshop 5 consideration memo at page 129, Appendix C-5A of Exhibit B-1, BC Hydro has already taken steps to acquire resources to meet its long term load forecasts. An RTP rate that converts a portion of this firm load growth to non-firm risks stranding investment that is already in service, under construction, or that BC Hydro has committed to build.

101.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4 Transmission Service, pp. 7-26 and 7-32
Freshet rate pilot

On page 7-26, "BC Hydro seeks approval of the freshet rate no later than February 1, 2016 as a two-year pilot to run between the May to July 2016 and May to July 2017 freshet periods."

On page 7-32:

During Workshop 10, BC Hydro acknowledged there are uncertainties associated with the freshet rate including take-up volumes. The best way to explore this while limiting risk to non-participating customers is to run the rate as a pilot for a period of time and evaluate results against predefined evaluation criteria (discussed below in section 7.3.4.6). BC Hydro considers that a two-year pilot is necessary to test the sensitivity of incremental load to changing market prices and to provide customers with sufficient potential benefit from the pilot to promote take-up. Stakeholders generally supported BC Hydro's two-year proposal.

1.101.1 Please provide any examples that BC Hydro is aware of where a new rate or program was initiated as a pilot and then reviewed and improved after an initial trial period.

RESPONSE:

An example is BC Hydro's RTP program (RS 1848) which was initially offered to Transmission Service customers on a trial basis for up to one year ending August 1997.

When the Commission approved the pilot rate it required "BC Hydro to monitor and examine various aspects of Rate Schedule 1848 and to file, at the end of the trial period, a proposal with the results of its examinations, evaluations, suggested criteria and procedures with respect to certain aspects of Rate Schedule 1848". BC Hydro filed this information along with a revised, longer term RTP rate in September 1997. Refer to Commission Order No. G-114-97 for additional background on RS 1848.

101.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4 Transmission Service, pp. 7-26 and 7-32
Freshet rate pilot

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1.101.2 Would establishing a rate and reviewing the rate after several years work equally well as a pilot program?

RESPONSE:

BC Hydro believes a pilot program (that terminates after a specific date) can be more appropriate than a normal rate (which normally has no termination date) if there is a high degree of uncertainty as to takeup. In addition, a pilot allows BC Hydro to test risk to participating and non-participating customers.
BC Hydro's experience is that once rates are established on a permanent basis, it is difficult to terminate them.

A pilot program provides the following:

- **A limited timeframe after which the pilot program terminates and an evaluation is performed; and**

- **More restrictive eligibility criteria that can permit a reduction in administration cost, a simpler evaluation, and the ability to minimize risks and uncertainty. A pilot program can be used to determine whether a rate can be broadened to a larger group of customers.**

101.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4 Transmission Service, pp. 7-26 and 7-32
Freshet rate pilot

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On page 7-32:

During Workshop 10, BC Hydro acknowledged there are uncertainties associated with the freshet rate including take-up volumes. The best way to explore this while limiting risk to non-participating customers is to run the rate as a pilot for a period of time and evaluate results against predefined evaluation criteria (discussed below in section 7.3.4.6). BC Hydro considers that a two-year pilot is necessary to test the sensitivity of incremental load to changing market prices and to provide customers with sufficient potential benefit from the pilot to promote take-up. Stakeholders generally supported BC Hydro's two-year proposal.

1.101.3 Please provide the anticipated costs in 2015$ of administering and reporting on the freshet rate during the pilot period.

RESPONSE:

No incremental costs are anticipated to arise from administering the freshet rate during the pilot period. Specifically, the costs to develop and maintain a new freshet rate during the pilot period (including billing) would be funded through BC Hydro's existing operating budgets and staff resources. While BC Hydro's costs for reporting would be dependent on the specific criteria set out by the BCUC, it is anticipated that any such costs would not exceed $50,000.

102.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.1 Transmission Service, p. 7-26; Figure 7-3
Freshet rate pilot

On page 7-26 of the Application BC Hydro concludes "The freshet rate would encourage customers to increase electricity consumption during the freshet period (May – July), when BC Hydro has a long-term recurring issue of energy oversupply."

1.102.1 Please discuss whether or not the oversupply is region specific. Could a freshet rate for specific oversupplied areas be more beneficial than providing for a freshet rate that is accessible to all RS 1823 customers across the province? Please elaborate.

RESPONSE:

Freshet oversupply is primarily a system-wide issue related to the concurrent timing of low system loads and high energy deliveries. Within BC Hydro's service area, transmission is generally designed to allow generation to operate at rated output and transmission path limits are not expected to be a constraint during the freshet period. Given that oversupply is primarily a system wide issue, BC Hydro views a freshet rate accessible to all RS 1823 customers across its service area as appropriate.

102.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.1 Transmission Service, p. 7-26; Figure 7-3
Freshet rate pilot

On page 7-26 of the Application BC Hydro concludes "The freshet rate would encourage customers to increase electricity consumption during the freshet period (May – July), when BC Hydro has a long-term recurring issue of energy oversupply."

1.102.2 Please compare the total energy available in each of BC Hydro's major reservoirs from their highest allowed annual operating level to their lowest allowed annual operating level to the energy expected from IPP, BC Hydro run-of-river, and other generation sources during the freshet period.

RESPONSE:

The following table specifies the expected (under average inflow conditions) total energy for each of the listed components in the freshet period of 2017.

Note that all values are in GWh.

Williston Storage Capability (2147 ft – 2205 ft)	**12,700**
Kinbasket Storage Capability (2320 ft – 2475 ft)	**10,550**
EPA Contract Deliveries During the Freshet	**4,970**
BC Hydro Non-Discretionary Generation at Plants Not Backed by System Storage During the Freshet	**6,500**
Total Non-Discretionary Generation at Plants Backed by System Storage (Mica, Revelstoke, Coordination Plant, GM Shrum, Peace Canyon) During the Freshet	**3250**

Due to prudent risk management practises, system constraints and the impacts of head losses, system storage reservoirs will rarely be utilized to the full extent of their energy storage capability within any one year. The graph in BC Hydro's response to BCUC IR 1.104.2 shows that a more typical range of combined system storage operation is about 15,500 GWh.

Note that looking at totals across the freshet does not provide a complete picture of the freshet surplus issues. For example, even in a year with low system inflows, a sudden heat wave that melts snowpack in the Revelstoke basin may result in minimum generation supply exceeding load for a number of days, during which period this surplus must be managed by exports or spills.

102.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.1 Transmission Service, p. 7-26; Figure 7-3
Freshet rate pilot

On page 7-26 of the Application BC Hydro concludes "The freshet rate would encourage customers to increase electricity consumption during the freshet period (May – July), when BC Hydro has a long-term recurring issue of energy oversupply."

1.102.3 Please confirm, otherwise explain, that run-of-river and other forms of energy production in BC (e.g. wind) that take place during the spring and early summer period allow BC Hydro to fill its large reservoirs (e.g. Kinbasket, Williston, Kootenay, Arrow) and store this energy for more optimal use in the winter.

RESPONSE:

Not Confirmed.

Energy storage in BC Hydro system reservoirs (Williston and Kinbasket Reservoirs) increases during the freshet due to runoff from snowmelt and rainfall. Production from these large basin generating stations may be reduced to minimum generation if system load can be met through alternative resources such as market and BC Hydro or IPP generation, permitting a somewhat greater volume of refill. Nonetheless, deposits to system storage can only come from inflows, and inflows minus minimum generation releases may not be sufficient to fill system storage across the freshet.

The growth of non-dispatchable freshet energy from contracted run-of-river IPP generation, coupled with existing non-discretionary BC Hydro run-of-river generation, have resulted in surplus energy that exceeds BC Hydro's capability to store, despite large basin generation being operated at minimum levels. The freshet rate pilot has been designed to reduce this energy surplus.

Kootenay Lake and Arrow Lakes Reservoir do not have sufficient flexibility to provide a material increase in usable system storage.

102.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.1 Transmission Service, p. 7-26; Figure 7-3
Freshet rate pilot

On page 7-26 of the Application BC Hydro concludes "The freshet rate would encourage customers to increase electricity consumption during the freshet period (May – July), when BC Hydro has a long-term recurring issue of energy oversupply."

1.102.3 Please confirm, otherwise explain, that run-of-river and other forms of energy production in BC (e.g. wind) that take place during the spring and early summer period allow BC Hydro to fill its large reservoirs (e.g. Kinbasket, Williston, Kootenay, Arrow) and store this energy for more optimal use in the winter.

1.102.3.1 If confirmed, does operating the BC system in such a manner allow BC Hydro to provide energy/capacity to its customers in the winter at cheaper rates than market prices during the winter?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.102.3.

102.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.1 Transmission Service, p. 7-26; Figure 7-3
Freshet rate pilot

On page 7-26 of the Application BC Hydro concludes "The freshet rate would encourage customers to increase electricity consumption during the freshet period (May – July), when BC Hydro has a long-term recurring issue of energy oversupply."

1.102.3 Please confirm, otherwise explain, that run-of-river and other forms of energy production in BC (e.g. wind) that take place during the spring and early summer period allow BC Hydro to fill its large reservoirs (e.g. Kinbasket, Williston, Kootenay, Arrow) and store this energy for more optimal use in the winter.

1.102.3.2 Similarly, does operating the BC system in such a manner allow BC Hydro and/or Powerex to export power at higher prices in the winter?

RESPONSE:

Storage of energy in the freshet will often be transferred into winter months to serve high winter time domestic loads. Any additional energy flexibility within the power system, from hour-by-hour, up to seasonal, will be optimized based upon market prices. The proposed freshet rate pilot does not increase storage levels in BC Hydro storage reservoirs. Rather, it provides a mechanism to reduce the amount of forced exports (or in the extreme, spills) from the BC Hydro system.

102.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.1 Transmission Service, p. 7-26; Figure 7-3
Freshet rate pilot

On page 7-26 of the Application BC Hydro concludes "The freshet rate would encourage customers to increase electricity consumption during the freshet period (May – July), when BC Hydro has a long-term recurring issue of energy oversupply."

1.102.3 Please confirm, otherwise explain, that run-of-river and other forms of energy production in BC (e.g. wind) that take place during the spring and early summer period allow BC Hydro to fill its large reservoirs (e.g. Kinbasket, Williston, Kootenay, Arrow) and store this energy for more optimal use in the winter.

1.102.3.3 If customers consume additional energy during the freshet period, would this reduce the amount of power BC Hydro and/or Powerex would otherwise have available to export in the winter and/or sell to its customers? Please explain.

RESPONSE:

The freshet rate was initiated to mitigate the system energy surplus in the freshet. This surplus energy cannot be stored in large reservoirs in the system, and as such must be sold into low priced freshet power markets.

However, if customers shift their load from the winter period to the freshet period BC Hydro would have lower winter loads which could allow BC Hydro/Powerex to increase exports in the winter.

102.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.1 Transmission Service, p. 7-26; Figure 7-3
Freshet rate pilot

On page 7-26 of the Application BC Hydro concludes "The freshet rate would encourage customers to increase electricity consumption during the freshet period (May – July), when BC Hydro has a long-term recurring issue of energy oversupply."

1.102.3 Please confirm, otherwise explain, that run-of-river and other forms of energy production in BC (e.g. wind) that take place during the spring and early summer period allow BC Hydro to fill its large reservoirs (e.g. Kinbasket, Williston, Kootenay, Arrow) and store this energy for more optimal use in the winter.

1.102.3.4 What value does the loss of this arbitrage opportunity have?

RESPONSE:

No arbitrage opportunity exists. Please refer to BC Hydro's response to BCUC IR 1.102.3.3.

103.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4 Transmission Service, pp. 7-27 and 7-28
Freshet rate pilot

On pages 7-27 and 7-28, BC Hydro's describes its objectives as follows:

1. Respond to the IEPR task force's recommendation to develop additional options for industrial customers;
2. Assist in the management of the freshet oversupply in the BC Hydro system by providing the option to:
   - increase the ability to import cheap electricity during low priced periods;
   - reduce the volume of surplus energy being forced to export markets; and/or
   - reduce spill at BC Hydro facilities; and
3. Recover what BC Hydro would otherwise obtain on the export market, but with potential economic benefits for B.C.

1.103.1 Should there be a fourth objective to "share the benefits from the freshet rate with all BC Hydro ratepayers"? Why or why not?

RESPONSE:

BC Hydro does not agree that there should be a fourth objective to "share the benefits of the freshet rate with all BC Hydro ratepayers" for the following reasons:

1) **The IR implies that to meet the *UCA* fair, just and not unduly discriminatory legal test, the freshet rate pilot must deliver benefits to non-participating customers. BC Hydro does not accept that the *UCA*'s legal test requires such an outcome; and**

2) **In both the Workshop 10 consideration memo found at Exhibit B-1, Appendix C-5B, page 81 of 212, and at page 7-27 of Exhibit B-1, BC Hydro stated that it designed the freshet rate pilot to hold harmless non-participating customers. The benefits listed under objective 2 on pages 7-27 and 7-28 of Exhibit B-1 accrue to all BC Hydro ratepayers. The dollar value of these benefits is difficult to quantify but BC Hydro believes it is positive.**

104.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4 Transmission Service, Figure 7-2
Freshet rate pilot

"Figure 7-2, based on normal water conditions and forecast calendar 2017 load and generation, shows that system inflows and contracted IPP supply (Total EPAs) on the BC Hydro system are expected to exceed load by a significant margin between mid-April and the end of August."

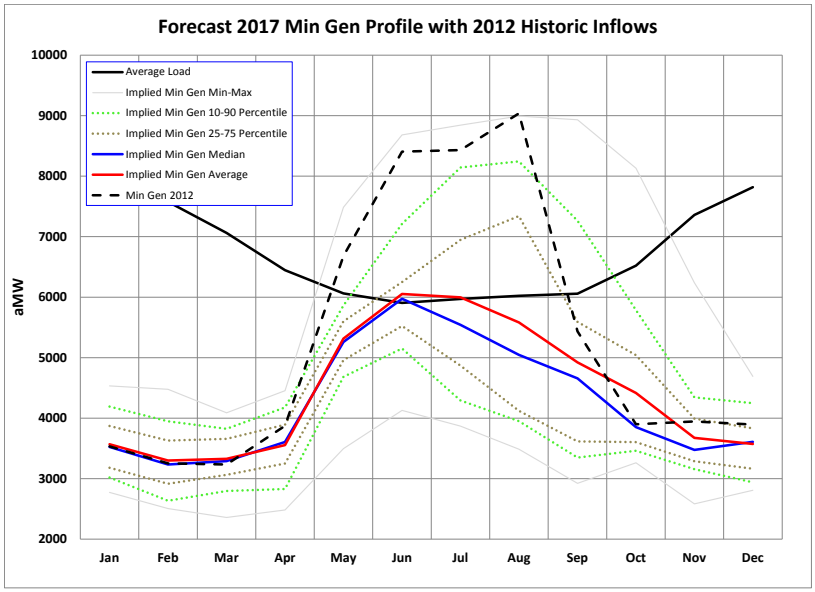
1.104.1 Please provide similar figures based on actual inflows in 2013, 2014 and 2015. Based on those actual inflows, what impact would they have had on the availability of Freshet electricity?

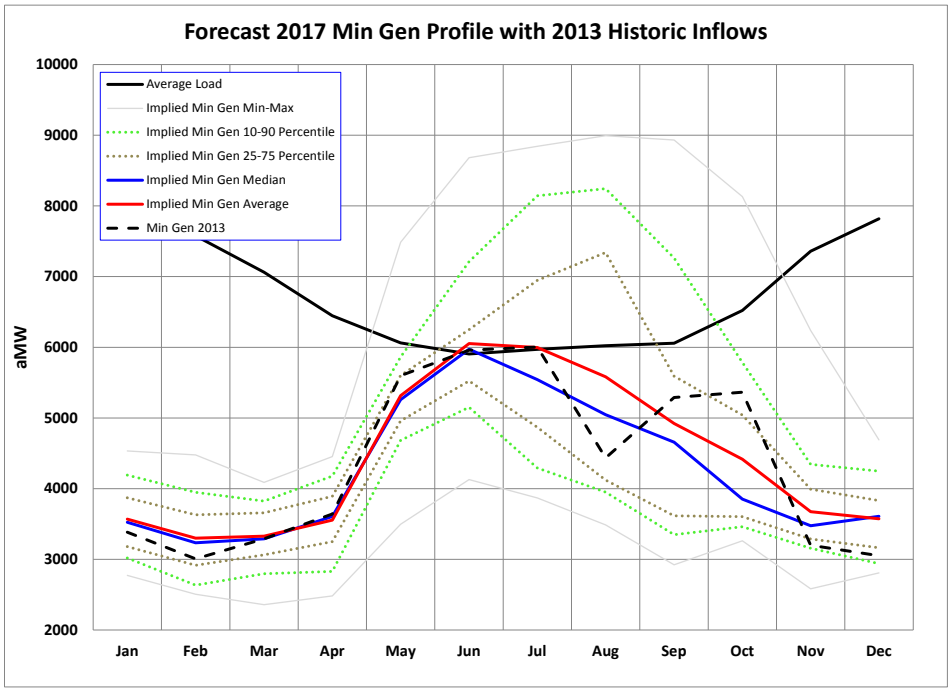
RESPONSE:

The hour glass charts best illustrate the impact of historic inflow conditions on the availability of freshet electricity in 2017. The following four charts are based on the latest (October 2015) forecasts of loads. In other words, the graphs represent the forecast of the impact on the system in 2017 under historic inflow conditions. They do not represent the historic operation of the system nor the imports/exports in the respective historic years, because both the load and non-discretionary generation resources were lower then.

For comparison purposes, the high inflow year 2012 is also included. Since 2015 inflows are not complete, they cannot be included in the modeling. As a result, the most representative historic year (1992) was used as a proxy.

Note also that these graphs represent monthly average minimum generation constraints, and on any particular day within the month there may be materially greater or lesser amounts of surplus energy, depending on the weather.




Forecast 2017 Min Gen Profile with 2013 Historic Inflows
Average Load
Implied Min Gen Min-Max
Implied Min Gen 10-90 Percentile
Implied Min Gen 25-75 Percentile
Implied Min Gen Median
Implied Min Gen Average
Min Gen 2013
aMW
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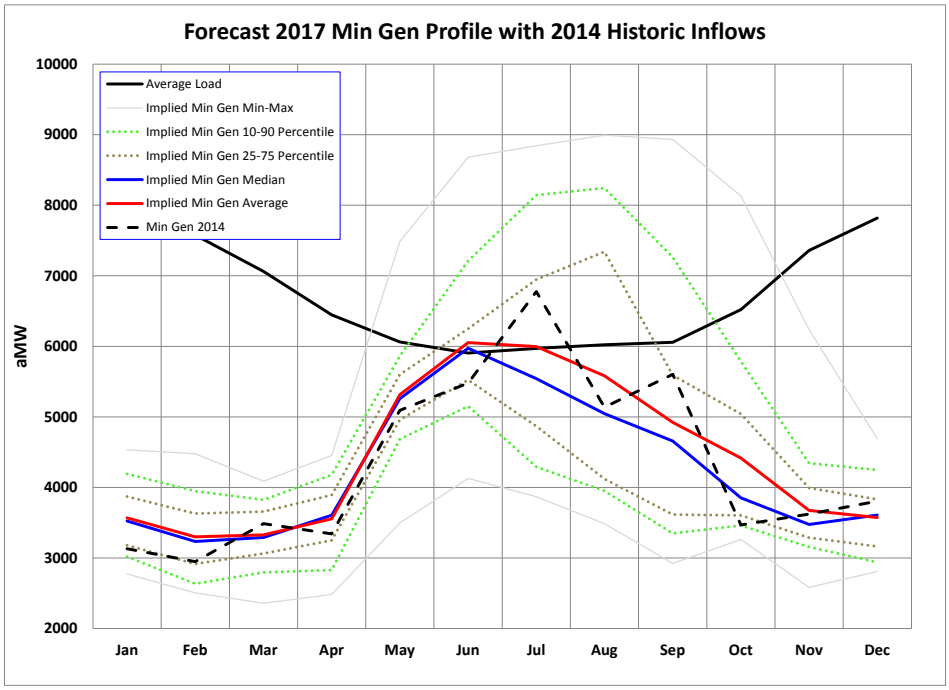
Forecast 2017 Min Gen Profile with 2014 Historic Inflows
Average Load
Implied Min Gen Min-Max
Implied Min Gen 10-90 Percentile
Implied Min Gen 25-75 Percentile
Implied Min Gen Median
Implied Min Gen Average
Min Gen 2014
aMW
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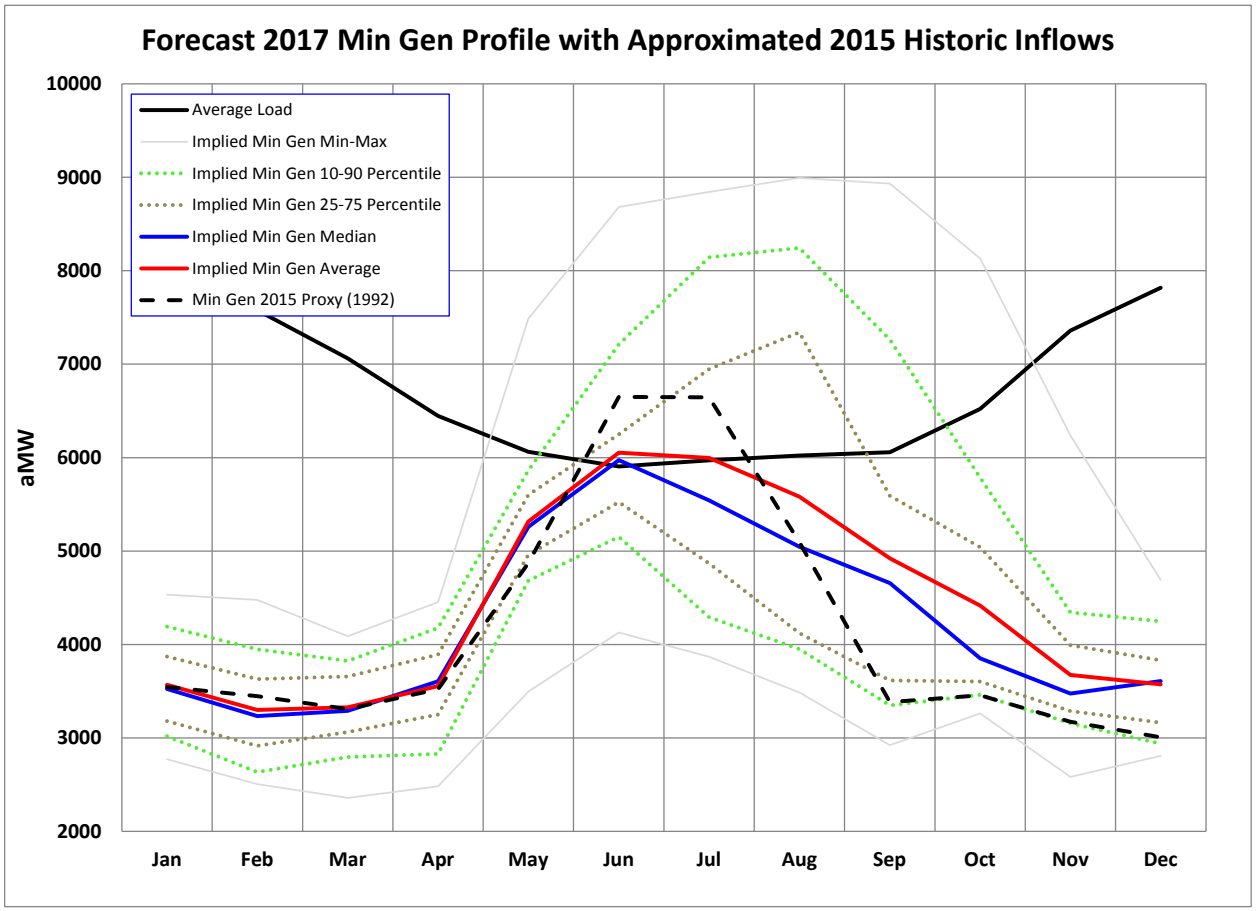
Forecast 2017 Min Gen Profile with Approximated 2015 Historic Inflows
aMW
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7000
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May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Average Load
Implied Min Gen Min-Max
Implied Min Gen 10-90 Percentile
Implied Min Gen 25-75 Percentile
Implied Min Gen Median
Implied Min Gen Average
Min Gen 2015 Proxy (1992)

104.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4 Transmission Service, Figure 7-2
Freshet rate pilot

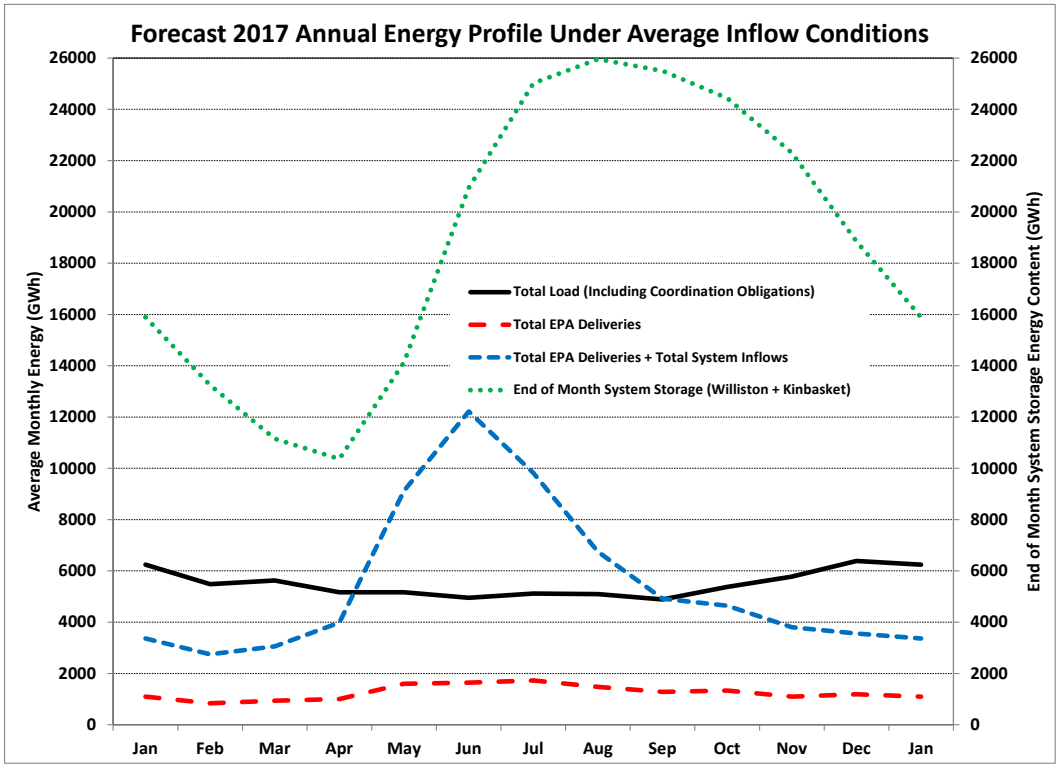
"Figure 7-2, based on normal water conditions and forecast calendar 2017 load and generation, shows that system inflows and contracted IPP supply (Total EPAs) on the BC Hydro system are expected to exceed load by a significant margin between mid-April and the end of August."

1.104.2 Please provide an updated Figure 7-2 to show the impact of storing water as well as serving load.

RESPONSE:

This figure has been updated based on the latest (October 2015) energy study, with the addition of a plot trace showing system storage energy content. In this figure, system storage energy content is the optimal trajectory based on maximizing net revenue based on market electricity purchases and sales.

As can be seen in the figure, system storage increases across the freshet when total EPA deliveries plus system inflows exceeds the total load, and decreases as it is drawn down to serve the load across the winter.



105.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4 Transmission Service, p. 7-29 & Workshop 10 slide 22
Freshet rate pilot

"During the freshet period, there is a higher risk of minimum generation constraints which reduce BC Hydro's flexibility to take advantage of low Mid-C prices, especially in LLH, by importing more energy from the U.S. market."

1.105.1 Please further explain the impact of minimum generation constraints shown on the figure at slide 22 of Workshop 10.

RESPONSE:

Minimum generation constraints occur when all hydro generation with usable storage flexibility is reduced to minimum output consistent with meeting water license and other regulatory obligations while maintaining prudent spill risk.

Recent purchases of run-of-river and other non-dispatchable IPP energy coupled with BC Hydro's own existing non-discretionary generation have the effect of changing BC Hydro's operations during much of the freshet period. In particular, as the total volume of freshet generation increases the ability of the system to absorb low-priced imports decreases until the system is forced to export increasing volumes at unattractive (low or negative prices).

When export tie limits are reached, any additional energy must be spilled.

Note that the magnitude and timing of this generation within the freshet period is critical to the operation of the system, not only the total volume in the freshet.

Projecting forward, with all system storage-backed generation operating at minimum, additional EPA contract deliveries are expected to result in surplus energy in the system during the freshet. Marginal increases in load during this period will mitigate the operational impacts.

The hourglass plots supplied in BC Hydro's response to BCUC IR 1.104.1 illustrate this issue. When the dashed black line is above the solid black line, there will be surplus energy in the system that must be either sold to the market or spilled.

106.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4 Transmission Service, pp. 7-29, 7-30
Freshet rate pilot

BC Hydro describes the 2015 freshet period as unusual due to early melt of winter snowpack and low rainfall across the freshet months. As a result, overall flow for the May to July 2015 period in the US Columbia River was the third lowest in 55 years. Consequently, Canadian dollar Mid-C market prices during the 2015 freshet were considerably higher than past periods given these drought conditions and a significant depreciation in the Canadian/US dollar exchange rate from an average of 0.97 in the period 2010 to 2014 to an average of 0.80 during the first seven months of 2015.

1.106.1 If the drought conditions of 2015 reoccur during the freshet rate pilot period, does BC Hydro anticipate that the higher prices and lower availability could result in revenue under collection and risk of future cost recovery from non-participating customers? Please explain why or why not.

RESPONSE:

The freshet rate is designed to recover BC Hydro's costs while holding harmless non-participating customers. The rate charges customers the actual market price plus a proxy wheeling fee. If drought conditions reoccur, prices will likely be higher which may reduce purchases by participating customers under the rate.

107.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, p. 7-35 & Workshop 10 memo, p. 34 Freshet Rate Pilot

On page 7-35, BC Hydro states "Initially, freshet energy volumes will be calculated hourly by determining energy consumption in excess of an average MW (**aMW**) baseline determined in consultation with the participating customer."

BC Hydro sought feedback on four baseline options on slide 27 of the Workshop 10 presentation and ultimately received broad stakeholder support for pursuing Option 3, an average MW baseline discussed on page 34 of the Workshop 10 consideration memo, giving customers the ability to respond to daily HLH and LLH price signals. Options 1 and 2 were rejected because they used average freshet prices, across an entire month or season, and would have sent customers an inferior price signal relative to the use of an average MW baseline in Option 3.

First Nations Energy and Mining Council (FNEMC) suggested in Workshop 10 that different lengths of baseline periods (3 months, monthly, daily, hourly) be evaluated.

1.107.1 Is there a way that FNEMC's suggestions on page 34 of the Workshop 10 Consideration Memo can be evaluated during the pilot period?

RESPONSE:

BC Hydro assessed FNEMC's suggestions as part of the Workshop 10 consideration memo found at Exhibit B-1, Appendix C-5B, page 86 of 212.

The following summarizes that assessment:

BC Hydro does not believe it is possible to test the four baseline lengths listed because a minimum of three to five customers would need to use each baseline type, which implies that a minimum of 12 to 20 different customers would need to take the freshet rate. On page 88 of 212 of the Workshop 10 consideration memo, Appendix C-5B of Exhibit B-1, BC Hydro indicated that its consultations with transmission-voltage load customers indicate a range of five average MW to 30 average MW of freshet rate consumption. This consumption range is likely to come from one to five customers rather than 12 to 20 customers.

BC Hydro's objective in designing the freshet rate is to obtain a net gain in energy consumption over the entire three-month period. Monthly, daily or hourly CBLs may not accomplish this objective because customers could benefit from the rate by increasing consumption in certain months, days or hours even though there may not be a net gain in freshet consumption because the customers have decreased consumption in other periods. If baselines don't cover the entire freshet period, BC Hydro believes that penalty mechanisms would be required to incent a net gain in consumption across the freshet period.

108.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, pp. 7-37 and 7-38
Freshet rate pilot

On page 7-37, BC Hydro states that "In the Workshop 10 presentation slide deck and consideration memo, BC Hydro stated the wheeling fee was both a cost recovery mechanism and a tool to protect non-participating ratepayers from risks associated with the freshet rate. BC Hydro now proposes a lower proxy (fixed at $CDN 3/MWh) for the following reasons." The reasons provided are: (a) cost justification and (b) risk justification.

BC Hydro considers a proxy wheeling fee of $CDN 3/MWh appropriate given the cost rationale and the fact there are risks to non-participating customers. This proposed fee is approximately 50 percent of the BPA wheeling fee that BC Hydro proposed at Workshop 10.

1.108.1 Why did BC Hydro decrease the proposed wheeling fee from the original suggestion of $6/MWh?

RESPONSE:

In addition to the reasons listed on pages 7-37 and 7-38 of Exhibit B-1, BC Hydro reduced the wheeling fee based on feedback received during Workshop 10 and during meetings with AMPC on August 28, 2015, September 3, 2015, and September 15, 2015[1]. During the September meetings AMPC observed that the application of a wheeling fee should be symmetric with BC Hydro charging the fee when imports increase to serve incremental freshet load and crediting the fee when exports decrease to serve the incremental load. BC Hydro agrees with this observation and considered weighting the number of import and export hours to calculate a wheeling fee but rejected this idea because it would be complex and subject to considerable variability because system import and export behaviour during the freshet is a function of many factors and is highly variable year over year. This variability is shown on page 23 of 212 of the Workshop 10 slide deck, Appendix C-5B of Exhibit B-1.

BC Hydro considers a $3/MWh proxy wheeling fee to be reasonable because it recovers the import costs and also offsets some of the other risks faced by non-participating customers, which are expected to be small.

[1] **These meetings are described on page 2-27 of Exhibit B-1.**

108.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, pp. 7-37 and 7-38
Freshet rate pilot

On page 7-37, BC Hydro states that "In the Workshop 10 presentation slide deck and consideration memo, BC Hydro stated the wheeling fee was both a cost recovery mechanism and a tool to protect non-participating ratepayers from risks associated with the freshet rate. BC Hydro now proposes a lower proxy (fixed at $CDN 3/MWh) for the following reasons." The reasons provided are: (a) cost justification and (b) risk justification.

BC Hydro considers a proxy wheeling fee of $CDN 3/MWh appropriate given the cost rationale and the fact there are risks to non-participating customers. This proposed fee is approximately 50 percent of the BPA wheeling fee that BC Hydro proposed at Workshop 10.

1.108.2 Are there likely cases where the higher $6/MWh fee would inhibit use of the freshet rate?

RESPONSE:

Yes.

BC Hydro considers that customers will likely require a differential of $10/MWh to justify changes in behavior that would lead to incremental purchases during the freshet period. A higher wheeling fee would reduce this differential and potentially inhibit use of the freshet rate.

Figures 7-4 and 7-5 of Exhibit B-1 are histograms showing the number of hours with different differentials between the RS 1823 Tier 1 rate and CDN$ Mid-C prices in both HLH and LLH periods. As stated in BC Hydro's response to BCOAPO IR 167.2.1, the wheeling fee is not included in these figures. The figures show that there are many hours where the differential is less than $10/MWh or even negative.

For the years 2010 to 2015 the table below summarizes the number of hours in the freshet period where the differential was CDN $10/MWh or greater under three cases:

- **Case 1) No wheeling fee;**
- **Case 2) $3/MWh wheeling fee; and**
- **Case 3) $6/MWh wheeling fee.**

In every year and in both HLH and LLH periods the $6/MWh wheeling fee reduces the number of hours with at least a $10/MWh differential. This implies that an increase in the wheeling fee to $6/MWh is likely to reduce customer participation in the freshet rate pilot and the volume of freshet energy consumed. Note that the price floor is accounted for in these calculations.

Number of Freshet Hours with at least a $10/MWh differential						
	HLH			LLH		
	Case 1	Case 2	Case 3	Case 1	Case 2	Case 3
2010	240	192	160	432	336	328
2011	224	80	0	976	920	832
2012	992	880	816	984	992	992
2013	0	0	0	560	472	328
2014	16	0	0	656	616	536
2015	96	16	0	976	976	0

108.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, pp. 7-37 and 7-38
Freshet rate pilot

On page 7-37, BC Hydro states that "In the Workshop 10 presentation slide deck and consideration memo, BC Hydro stated the wheeling fee was both a cost recovery mechanism and a tool to protect non-participating ratepayers from risks associated with the freshet rate. BC Hydro now proposes a lower proxy (fixed at $CDN 3/MWh) for the following reasons." The reasons provided are: (a) cost justification and (b) risk justification.

BC Hydro considers a proxy wheeling fee of $CDN 3/MWh appropriate given the cost rationale and the fact there are risks to non-participating customers. This proposed fee is approximately 50 percent of the BPA wheeling fee that BC Hydro proposed at Workshop 10.

1.108.3 Can an appropriate wheeling rate be evaluated during the pilot period to set an appropriate fee for a later permanent program?

RESPONSE:

The proxy wheeling fee was set using professional judgement and it was not derived quantitatively. The fee was set based on the costs and risks described on pages 7-37 and 7-38 of Exhibit B-1.

Please refer to BC Hydro's response to BCUC IR 1.108.1 and BCOAPO IR 170.1 for further information on these costs and risks.

109.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, p. 7-38
Freshet rate pilot

BC Hydro identifies the following risk to non-participating customers: "Tie line constraints may limit BC Hydro's ability to import from the U.S. market, which means storage could be the source of energy used to supply incremental freshet load. In this situation, there would be opportunity costs if BC Hydro could have instead used the stored energy during a higher valued period."

1.109.1 Would BC Hydro interrupt freshet rate deliveries in this circumstance? If not, what other measures could BC Hydro take to prevent or mitigate lost opportunities? Please explain.

RESPONSE:

If BC Hydro needed to import to supply freshet customers and if the U.S. intertie was out of service and BC Hydro was unable to import energy to serve incremental freshet load, BC Hydro would assess the cost of serving the incremental load. The likelihood of this is considered to be extremely low. If the cost was deemed to be excessive relative to market prices, BC Hydro would likely curtail the customer.

110.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, pp. 7-32 and 7-39
Freshet rate pilot

Regarding Reference Baselines, BC Hydro states "So long as 2015 freshet purchases are within +/- 10 per cent of a customer's historical freshet load, BC Hydro expects to use the 2015 data without further adjustment."

On page 7-32 BC Hydro explains: "The rate is open to any RS 1823 customer during the freshet period. BC Hydro excluded RS 1827 customers because many of these customers, including New Westminster, naturally increase consumption year over year and might benefit from the freshet rate without a behavioural change."

1.110.1 What period constitutes the "historical" freshet load?

RESPONSE:

To determine if a customer's 2015 freshet consumption can be used to set a baseline without further adjustment, BC Hydro believes it's necessary to compare consumption in 2015 with the prior three to five year period. The exact period for comparison will be determined on a case by case basis and BC Hydro will be guided by the baseline setting principles set out in TS 74. Furthermore, Special Condition 4 of RS 1892 (Exhibit B-1, Appendix F-1B) states that BC Hydro will file baselines not based on 2015 freshet purchases with the Commission.

Setting baselines can be challenging for a variety of reasons because consumption in the baseline period can be affected by many factors including economic conditions, maintenance, production expansion, DSM, etc. Setting baselines ultimately requires a degree of professional judgement to ensure the baseline reasonably represents what the customer would have used in the absence of the freshet rate.

110.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, pp. 7-32 and 7-39
Freshet rate pilot

Regarding Reference Baselines, BC Hydro states "So long as 2015 freshet purchases are within +/- 10 per cent of a customer's historical freshet load, BC Hydro expects to use the 2015 data without further adjustment."

On page 7-32 BC Hydro explains: "The rate is open to any RS 1823 customer during the freshet period. BC Hydro excluded RS 1827 customers because many of these customers, including New Westminster, naturally increase consumption year over year and might benefit from the freshet rate without a behavioural change."

1.110.2 Is this a change from the process identified on page 34 of the Workshop 10 Memo?

RESPONSE:

Yes, because it is BC Hydro's intent to simplify the baseline establishment process and provide certainty to potential participants. However, BC Hydro also recognizes that baseline adjustments may be reasonable to apply in certain circumstances, even where 2015 freshet purchases are within +/-10 per cent of a customer's historical freshet load (such as when a power outage has reduced load or a generator failure has increased load by 10 per cent during the 2015 baseline period). Where such an event can be clearly identified and is considered unlikely to occur in future, it may be reasonable to adjust the baseline to remove its impact. Please also refer to BC Hydro's response to BCUC IR 1.110.1.

110.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, pp. 7-32 and 7-39
Freshet rate pilot

Regarding Reference Baselines, BC Hydro states "So long as 2015 freshet purchases are within +/- 10 per cent of a customer's historical freshet load, BC Hydro expects to use the 2015 data without further adjustment."

On page 7-32 BC Hydro explains: "The rate is open to any RS 1823 customer during the freshet period. BC Hydro excluded RS 1827 customers because many of these customers, including New Westminster, naturally increase consumption year over year and might benefit from the freshet rate without a behavioural change."

1.110.3 Please discuss how increased load in the Freshet Period due to natural load growth is accounted for. Do participants naturally benefit from natural load growth without a behavioral change under the Freshet Rate? If so, how does this affect non-participants?

RESPONSE:

It is possible for RS 1823 customer to benefit from the freshet rate because of normal load growth.

BC Hydro anticipates that customers participating in the freshet rate will likely be chemical or forestry producers. In recent years these industries have had low or negative growth in electricity consumption. As such, BC Hydro does not anticipate that natural load growth from freshet participants is a significant concern requiring adjustment.

If natural load growth occurs there would be an impact on non-participating customers to the extent any natural load growth is not reflected in the baselines set for participating customers. For example, if the natural load growth is already factored into BC Hydro's long-term load forecast BC Hydro may have already advanced or acquired resources to meet this firm load growth. If the growth is now eligible for the non-firm freshet rate there is a loss to ratepayers equal to the difference between BC Hydro's LRMC and the market price.

111.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, p. 7-40, Figure 7-6; Appendix C-5B, p. 38 Freshet rate pilot

Figure 7-6 shows estimated gains from a 1MW load.

In Appendix C-5B BC Hydro explains that it expects 5 to 30 MW of average incremental energy over the freshet period.

1.111.1 What is the total estimated increase in incremental energy consumption (MWh) over the Freshet Rate Freshet Period for each year of the pilot? How much is this worth to participants and non-participants?

RESPONSE:

BC Hydro estimates a range of 11 GWh/year to 66 GWh/year of incremental energy from the freshet pilot. This energy is associated with the 5 aMW to 30 aMW takeup range shown on the Workshop 10 slide deck page 38 of 212, of Appendix C-5B of Exhibit B-1. BC Hydro believes the takeup range applies to both years of the pilot because the number of customers that will use the rate and their total energy purchases are uncertain and dependent on a variety of factors such as the customers' ability to increase freshet consumption, the differential between Mid C market prices and RS 1823 rates, and whether customers are able to reduce RS 1823 energy purchases at the Tier 1 or Tier 2 rates by shifting load into the freshet.

Figure 7-6 in Exhibit B-1 estimates the value of an additional MW of freshet load to participating and non-participating customers. However, the benefits to non-participants do not include the system benefits listed under objective 2, on pages 7-27 and 7-28 of Exhibit B-1, which are difficult to quantify.

111.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.3 Transmission Service, p. 7-40, Figure 7-6; Appendix C-5B, p. 38 Freshet rate pilot

Figure 7-6 shows estimated gains from a 1MW load.

In Appendix C-5B BC Hydro explains that it expects 5 to 30 MW of average incremental energy over the freshet period.

1.111.2 Why is the 2015 gain to non-participating customers so large in comparison to the gain to the participating customer? Is this solely a result of the market impact of the drought conditions this past freshet period?

RESPONSE:

The gain to non-participating customers is large in comparison to the gain to participating customers for two reasons:

1. **Recent drought conditions in the U.S. Pacific Northwest increased average 2015 market prices which narrowed the differential between market prices and the RS 1823 Tier 1 rate. The result was a reduction in gains to participating customers;**

2. **The higher market prices in 2015 also resulted in BC Hydro exporting to the U.S. market in a higher proportion of hours than in 2013 or 2014. Since the $3/MWh wheeling fee was assumed to accrue to non-participating customers during times of export, gains to non-participating customers are higher than in previous years.**

The net result is an increase in the ratio: $\frac{\text{gains to non-participants}}{\text{gains to participants}}$

112.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.5 Transmission Service, p. 7-42 Footnote 285
Freshet Rate Pilot

"For example, if shifting results in a drop in both RS 1823 Tier 1 revenue and long run marginal costs, there could be benefits to other ratepayers because the Tier 1 rate is significantly less than BC Hydro's LRMC. If shifting results in a drop in RS 1823 Tier 2 revenue, the outcome may be neutral for non-participating customers as the revenue reduction would be reasonably offset by the fall in long run costs."

1.112.1 Please further explain this footnote, perhaps with a numerical example.

RESPONSE:

Assume the RS 1823 Tier 1 rate is $38/MWh and the LRMC is $85/MWh for purposes of responding to this IR. If the shift in customer consumption from non-freshet months into the freshet months results in a reduction in BC Hydro's long term load forecast, a revenue loss at the Tier 1 rate ($38/MWh) would be less than the reduction in long run costs ($85/MWh) while a revenue loss at the Tier 2 rate ($85/MWh) would be equal to the fall in long run costs and would therefore be neutral for non-participating customers.

113.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.3.4.6 Transmission Service, p. 7-43
Freshet rate pilot

BC Hydro proposes a number of Evaluation Criteria. They are:

- Did the rate provide RS 1823 customers with lower cost options?
- Did the rate have positive or negative impacts on non-participating customers?
- How many RS 1823 customers used the rate" what were the volumes of use? How did customers use the rate?
- To what extent did shifting contribute to higher freshet energy?
- Was there any shifting within the freshet period from HLH to LLH? And
- Were there any issues with setting baselines, implementation and billing?

1.113.1 Please link the Evaluation Criteria to the program objectives on pages 7-27 and 7-28, including Commission suggested objective 4 to "share the benefits from the freshet rate with all BC Hydro ratepayers."

RESPONSE:

The program objectives listed on pages 7-27 and 7-28 of Exhibit B-1 were not intended to be an exhaustive list. Rather, they are the primary drivers for BC Hydro pursuing a freshet rate.

As noted in BC Hydro's response to BCUC IR 1.103.1, BC Hydro has suggested that a 4th objective could be added to hold non-participating customers harmless.

Other objectives could include:

- **Minimizing administration costs;**
- **Ensuring the rate has a positive or neutral impact on participating customers' DSM savings; and**
- **Reducing any integration issues with other BC Hydro rates such as RS 1880.**

The following table maps the evaluation criteria to BC Hydro's four primary program objectives;

Program Objectives	Evaluation criteria
Respond to the IEPR task force's recommendation to develop additional options for industrial customers	• **Did the rate provide RS 1823 customers with lower cost options?** • **How many RS 1823 customers used the rate? What were the volumes of use? How did customers use the rate?** • **Were there any issues with setting baselines, implementation, or billing?**
Assist in the management of the freshet oversupply in the BC Hydro system by providing the option to: • **Increase the ability to import cheap electricity during low priced periods;** • **Reduce the volume of surplus energy being forced to export markets; and/or** • **Reduce spill at BC Hydro facilities.**	• **Did the rate have positive or negative impacts on non-participating customers?**
Recover what BC Hydro would otherwise obtain on the export market, but with five potential economic benefits for B.C.	• **Did the rate have positive or negative impacts on non-participating customers?** • **Did the rate provide RS 1823 customers with lower cost options and did this lead to any economic benefits for B.C.?**
Additional fourth objective added as noted in BC Hydro's response to BCUC IR 103.1: • **Hold non-participating customers harmless**	• **Did the rate have positive or negative impacts on non-participating customers?** o **To what extent did shifting contribute to higher freshet energy?** o **Was there any shifting within the freshet period from HLH to LLH?**

113.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

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Freshet rate pilot

BC Hydro proposes a number of Evaluation Criteria. They are:

- Did the rate provide RS 1823 customers with lower cost options?
- Did the rate have positive or negative impacts on non-participating customers?
- How many RS 1823 customers used the rate" what were the volumes of use? How did customers use the rate?
- To what extent did shifting contribute to higher freshet energy?
- Was there any shifting within the freshet period from HLH to LLH? And
- Were there any issues with setting baselines, implementation and billing?

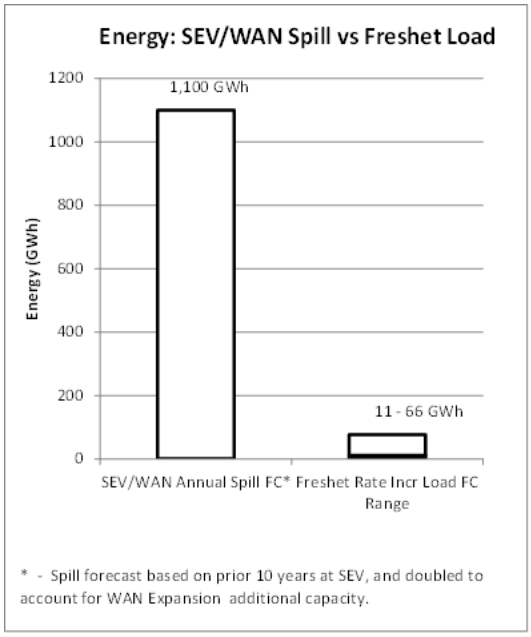
1.113.1 Please link the Evaluation Criteria to the program objectives on pages 7-27 and 7-28, including Commission suggested objective 4 to "share the benefits from the freshet rate with all BC Hydro ratepayers."

1.113.1.1 For example, considering BC Hydro suggests reducing spills at BC Hydro facilities could be a benefit of a freshet rate, could comparing spills at each BC Hydro generation facility year over year be an appropriate evaluation criteria? Please discuss.

RESPONSE:

Comparing spill at BC Hydro facilities year over year would not be an appropriate evaluation criteria. Any reduction in spill occurring under the freshet rate is expected to be very small relative to the overall volume of spill occurring across the BC Hydro system during the freshet. Refer to the graph below which compares historic spills at Seven Mile and Waneta with the estimated freshet takeup range of 11 GWh/year to 66 GWh/year shown in the response to BCUC IR 1.111.1.

BC Hydro considers spill reduction benefits to be of secondary importance relative to the other benefits listed under Objective 2, on pages 7-27 and 7-28 of Exhibit B-1.


Energy: SEV/WAN Spill vs Freshet Load
Energy (GWh)
1200
1000
800
600
400
200
0
1,100 GWh
11 - 66 GWh
SEV/WAN Annual Spill FC*
Freshet Rate Incr Load FC Range
* - Spill forecast based on prior 10 years at SEV, and doubled to account for WAN Expansion additional capacity.

114.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.4, Transmission Service, p. 7-44
RS 1853 – IPP Station Service

"There is a minimum monthly charge currently set at $41.37 (F2016) to recover costs incurred by BC Hydro under RS 1853. BC Hydro would continue with its existing practice of applying RRA rate increases to the RS 1853 minimum monthly charge of $41.37 (F2016)."

1.114.1 Is $41.37 adequate to cover the monthly costs to BC Hydro? If not, wouldn't this RDA be the time to revise the monthly charge?

RESPONSE:

Yes, $41.37 is adequate to cover the F2016 monthly costs to BC Hydro under RS 1853.

115.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.4 Transmission Service, p. 7-45 & Workshop 10 Memo, pp. 49 and 50
Pricing of RS 1853 – IPP Station Service vs RS 1880 – Standby and Maintenance

On page 7-45, BC Hydro states:

Feedback from other stakeholders was limited, with the only issue identified concerning whether the energy rates for RS 1853 and RS 1880 should be aligned – RS 1853 is based on Mid-C market prices and RS 1880 is set to the prevailing RS 1823 Tier 2 rate. At Workshop 10, BC Hydro provided its view that non-firm energy sold to IPPs should be priced off the Mid-C market because non-firm energy acquired from IPPs is typically priced at Mid-C, thus ensuring that non-firm energy is consistently valued whether it flows from BC Hydro to the IPP customer or from the IPP service provider to BC Hydro.

1.115.1 BC Hydro seems to estimate that an additional $2 million might be collected from RS 1880 customers by using the expected higher RS 1823 Tier 2 price compared to Mid-C. RS 1880 customers seem to prefer the price certainty of the Tier 2 pricing compared to volatile Mid C prices. Is the lack of a material revenue difference between the two pricing concepts the main reason why BC Hydro proposes maintaining the status quo Tier 2 pricing for RS 1880?

RESPONSE:

BC Hydro did not consider the lack of a material revenue difference between the two pricing concepts as the main reason why BC Hydro proposes maintaining the status quo RS 1823 Tier 2 pricing for RS 1880.

Section 7.4.3.2 of Exhibit B-1 provides two reasons why BC Hydro proposes maintaining the status quo Tier 2 pricing for RS 1880: Transmission Service customers who use the rate expressed no concerns regarding the existing RS 1880, and basing the RS 1880 energy rate on the RS 1823 Tier 2 rate rather than lower spot market prices helps ensure that any incremental costs are recovered from customers using the non-firm services. In addition, BC Hydro had observed that RS 1880 customers seem to prefer the price certainty of the Tier 2 pricing compared to volatile Mid C prices.

115.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.4 Transmission Service, p. 7-45 & Workshop 10 Memo, pp. 49 and 50
Pricing of RS 1853 – IPP Station Service vs RS 1880 – Standby and Maintenance

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1.115.2 Are there any other non-firm rate schedules with energy rates based on RS 1823 Tier 2 (e.g., shore power rate)? Please provide a list of the rate schedules.

RESPONSE:

Yes, there are three other non-firm rates – TS 76 (Agreement for Provision of Shore Service to Canada Place), RS 1280 Shore Power Service (Distribution) and RS 1891 Shore Power Service (Transmission) – that have energy rates based on the RS 1823 Tier 2 rate.

115.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.4 Transmission Service, p. 7-45 & Workshop 10 Memo, pp. 49 and 50
Pricing of RS 1853 – IPP Station Service vs RS 1880 – Standby and Maintenance

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1.115.3 Since the TSR was implemented, how frequently have spot market prices exceeded the RS 1823 Tier 2 rate?

RESPONSE:

Mid-C market prices exceeded the RS 1823 Tier 2 rate for a total of 6144 HLH and 1320 LLH between January 1, 2007 and October 31, 2015 (a total of 9.5 per cent of the time). The majority of these times occurred in 2007 and 2008. The number of hours where the Mid-C market price exceeds the Tier 2 rate is shown in the figures below, with number of hours grouped according to how much the Mid-C price exceeded the RS 1823 Tier 2 rate and calendar year.

Figure 1 HLH Differentials between Tier 2 Rate and $CDN Mid-C Price (HLH Market price – Tier 2 Rate)

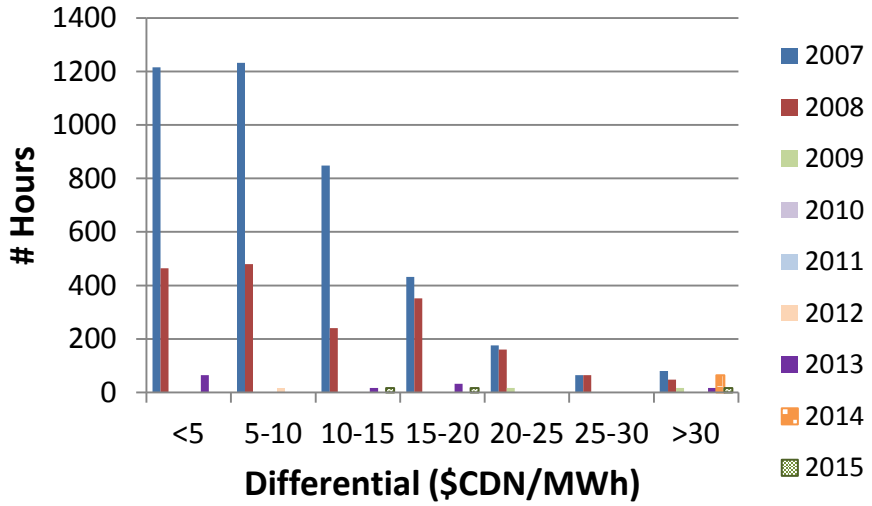
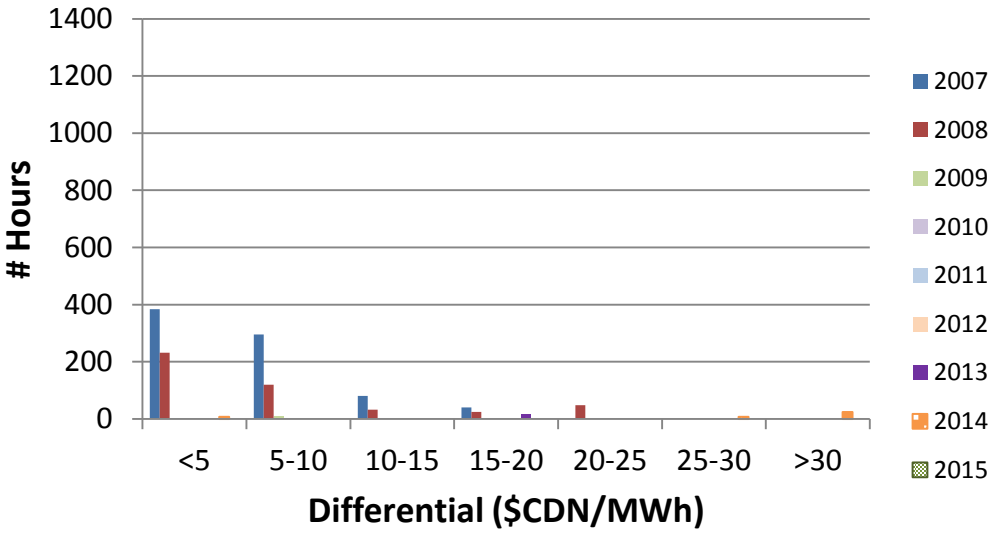


Figure 2 LLH Differentials between Tier 2 Rate and $CDN Mid-C Price (LLH Market price – Tier 2 Rate)



115.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

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Pricing of RS 1853 – IPP Station Service vs RS 1880 – Standby and Maintenance

On page 7-45, BC Hydro states:

Feedback from other stakeholders was limited, with the only issue identified concerning whether the energy rates for RS 1853 and RS 1880 should be aligned – RS 1853 is based on Mid-C market prices and RS 1880 is set to the prevailing RS 1823 Tier 2 rate. At Workshop 10, BC Hydro provided its view that non-firm energy sold to IPPs should be priced off the Mid-C market because non-firm energy acquired from IPPs is typically priced at Mid-C, thus ensuring that non-firm energy is consistently valued whether it flows from BC Hydro to the IPP customer or from the IPP service provider to BC Hydro.

1.115.4 If the Mid-C pricing is in a negative range, does BC Hydro still rely on Mid-C pricing for IPP customers taking services under TS 1853?

RESPONSE:

Yes, BC Hydro still relies on the Mid C pricing if it is negative as this is in accordance with RS 1853.

116.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.4.3 Transmission Service, p. 7-46
RS 1880 – standby and maintenance

"There is an administrative charge of $150 per incident (period of use) to recover the incremental costs incurred by BC Hydro resulting from a customer's request for service under RS 1880. This charge has been unchanged since it came into effect in early 2006." And "While the RS 1880 administrative charge is reasonable, and while labour costs associated with administering RS 1880 (e.g., manual billing adjustments for RS 1880 requests) are minor, it is difficult to say with certainty whether the administrative charge under or over recovers actual labour costs."

1.116.1 What is BC Hydro's best estimate of the appropriate cost in F2016 and why was it not included in the RDA?

RESPONSE:

BC Hydro's best estimate of the appropriate RS 1880 administrative cost in F2016 is $174 per incident. This estimate was not included in Exhibit B-1, since BC Hydro did not have this information available at the time.

117.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.5 Transmission Service, pp. 7-48 to 7-50
RS 1827 – exempt customers

On page 7-48, BC Hydro states that

SFU and YVR took the position that a review of the reasons for exemption should not be examined as part of the 2015 RDA. A common element of their respective responses is that application of a stepped rate has not been required to induce investment in energy efficiency since a significant amount of DSM projects have been undertaken to date while receiving electrical service under RS 1827...

On page 7-49, BC Hydro states "While overall the RS 1827 energy charge is not an efficient rate as it is below BC Hydro's energy LRMC range, there does not appear to be any significant change in circumstance for SFU or YVR since their original exemption from stepped rates in 2006."

On page 7-50, BC Hydro states "… the B.C. Government is of the view that the Commission's original rationale for exempting SFU and YVR from RS 1823 and other stepped rates continues to apply."

1.117.1 Does BC Hydro have information related to the DSM investments of SFU and YVR in terms of total costs and conservation savings?

RESPONSE:

SFU provided BC Hydro with the following information. Since 2002, SFU has spent approximately $8 million on electricity conversation initiatives, including $2.3 million in incentive funding from BC Hydro. These initiatives have resulted in 18.3 GWh of electricity savings.

YVR provided BC Hydro with the following information. Since 2009, YVR has spent approximately $30 million on electricity conservation initiatives, resulting in savings of 11.3 GWh plus additional savings yet to be measured. BC Hydro contributions to these initiatives were $1.8 million.

117.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.5 Transmission Service, pp. 7-48 to 7-50
RS 1827 – exempt customers

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On page 7-50, BC Hydro states "… the B.C. Government is of the view that the Commission's original rationale for exempting SFU and YVR from RS 1823 and other stepped rates continues to apply."

1.117.2 On a percentage basis, how have the DSM achievements of SFU and YVR compared with those of BC Hydro's residential customers, general service customers and industrial customers?

RESPONSE:

As provided in BC Hydro's response to BCUC IR 1.117.1, BC Hydro has information on the DSM investments of SFU and YVR in terms of total costs and conservation savings. However, it is BC Hydro's view that comparing the DSM investments of SFU and YVR to DSM investments across five broad customer classes is not meaningful because each customer has different drivers for making DSM investments.

SFU and YVR were exempted from RS 1823 and/or a stepped rate similar to RS 1823 due to having various loads behind their transmission service that they do not control. Since this remains the case for both SFU and YVR, BC Hydro believes that both customers should keep their exemption status. In addition, BC Hydro prioritizes the Bonbright customer understanding and acceptance, and rate stability, criteria over the Bonbright efficiency criterion for purposes of RDA Module 1 and particularly in respect of RS 1827. In this regard, BC Hydro notes:

- **SFU and YVR oppose transfer from RS 1827 to RS 1823 or a stepped rate. Refer to: SFU's intervention application (Exhibit C7-1) and September 10, 2015 letter of support (Exhibit B-1, Appendix C-5E, pages 1 to 6 of 11); and to YVR's September 11, 2015 letter of support (Exhibit B-1, Appendix C-5E, pages 7 to 9 of 11); and**

- **The MEM Policy Letter with respect to SFU and YVR and continuation of the exemption. Please refer to Appendix C-1C of Exhibit B-1.**

117.0 F. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, Application, Section 7.5 Transmission Service, pp. 7-48 to 7-50
RS 1827 – exempt customers

On page 7-48, BC Hydro states that

SFU and YVR took the position that a review of the reasons for exemption should not be examined as part of the 2015 RDA. A common element of their respective responses is that application of a stepped rate has not been required to induce investment in energy efficiency since a significant amount of DSM projects have been undertaken to date while receiving electrical service under RS 1827...

On page 7-49, BC Hydro states "While overall the RS 1827 energy charge is not an efficient rate as it is below BC Hydro's energy LRMC range, there does not appear to be any significant change in circumstance for SFU or YVR since their original exemption from stepped rates in 2006."

On page 7-50, BC Hydro states "… the B.C. Government is of the view that the Commission's original rationale for exempting SFU and YVR from RS 1823 and other stepped rates continues to apply."

1.117.2 On a percentage basis, how have the DSM achievements of SFU and YVR compared with those of BC Hydro's residential customers, general service customers and industrial customers?

1.117.2.1 If they have been significantly less than BC Hydro's comparable customers, would BC Hydro seek a stepped pricing structure for SFU and YVR?

RESPONSE:

No. Please refer to BC Hydro's response to BCUC IR 1.117.2.

118.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.2, p. 5-8 Electric Tariffs Terms and Conditions
Proposed review of standard charges between rate design applications

On page 8-5 of its Application, BC Hydro states that "RRAs are the appropriate forum for updates of existing Standard Charges to reflect current costs."
BC Hydro seeks the Commission endorsement of the described review process.

1.118.1 Does BC Hydro propose that Standard Charges will be reviewed through the revenue requirement applications with the objective of applying approved rate changes to Standard Charges or only adjusting Standard Charges for inflation or some other index? Please discuss.

RESPONSE:

BC Hydro is not proposing that approved revenue requirements be applied to the Standard Charges. Standard Charges are intended to recover BC Hydro's costs attributable to each of the charges. BC Hydro will review the costs of the Standard Charges in future RRAs and seek approval to update them to reflect its costs.

Any material changes to the cost methodology of the Standard Charges would be addressed in future RDAs.

119.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.1, pp. 8-6 and 8-7
Minimum connection charges – 400A overhead

BC Hydro submits on page 8-7 of its Application the following:

…due to system requirements 400A service requests often require additional transformation costs that are not included in the Minimum Connection Charge and would often require the creation of a distribution design for the installation which would include additional non-standard charges. To avoid customer confusion, BC Hydro is proposing to eliminate the 400A Minimum Connection Charge and address such service requests through the Distribution extension provisions in section 8 of the Electric Tariff.

1.119.1 For each of F2012, F2013 and F2014, please provide the number of 400A service requests received by BC Hydro, the total 400A service request revenue received and the average actual cost per 400A service request.

RESPONSE:

Fiscal Years	No. of Service Orders - 400A	Sum of Standard Charge ($)	No. of Designs - 400A	Sum of Customer Revenue ($)	Total 400A Requests	Total 400A Revenue ($)	Average Revenue ($)
FY12	117	93,366	112	533,850	229	627,216	2739
FY13	96	76,608	166	831,719	262	908,327	3467
FY14	91	72,618	113	674,596	204	747,214	3663
Total					695	2,282,757	3285

119.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.1, pp. 8-6 and 8-7
Minimum connection charges – 400A overhead

BC Hydro submits on page 8-7 of its Application the following:

…due to system requirements 400A service requests often require additional transformation costs that are not included in the Minimum Connection Charge and would often require the creation of a distribution design for the installation which would include additional non-standard charges. To avoid customer confusion, BC Hydro is proposing to eliminate the 400A Minimum Connection Charge and address such service requests through the Distribution extension provisions in section 8 of the Electric Tariff.

1.119.2 Please provide an updated 400A overhead service charge, including supporting calculations, using weighted average times and costs for BC Hydro's service area, and F2016 Standard Labour Rates (SLR), similar to the calculations provided in Appendix G-1B.

RESPONSE:

<u>Minimum Connection Charges: Overhead 400 AMPS - Updated</u>

Based on system weighted average times and costs for BC Hydro's service area:

<u>Total Labour (SLRs including benefits & concessions)</u>

Crew 2 Power Line Technicians

Labour 1.4 hours site time + 0.77 hours travel time = 2.17 hours

Total Labour (including benefits & concessions and field loading)

= 2.17 hours x $82.99 (unloaded Standard Labour Rate) x 2 = $360.18

<u>Material Cost + Material Handling charges</u>

Material Cost = service conductor and related materials = $222.75

<u>Vehicle Cost</u>

Vehicle Use is determined as a percentage of labour required (vehicle types vary across the province)

Vehicle Cost=29% x $360.18

(total labour hours*unloaded labour cost*crew)	**=**	**$104.45**
Subtotal		**$687.38**
Overhead Loadings = 27% x $953.38**	**=**	**$185.59**
TOTAL FOR SERVICE	**=**	**$872.97**
ROUNDED	**=**	**$873**

**** Includes Indirect Customer Connections & Distribution Design Project costs, Customer Connections & Distribution Design Overhead, Distribution Overhead costs.**

119.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.1, pp. 8-6 and 8-7
Minimum connection charges – 400A overhead

BC Hydro submits on page 8-7 of its Application the following:

…due to system requirements 400A service requests often require additional transformation costs that are not included in the Minimum Connection Charge and would often require the creation of a distribution design for the installation which would include additional non-standard charges. To avoid customer confusion, BC Hydro is proposing to eliminate the 400A Minimum Connection Charge and address such service requests through the Distribution extension provisions in section 8 of the Electric Tariff.

1.119.3 As noted in Chapter 1, (p. 1-14) BC Hydro is proposing to address section 8 of the Tariff, which governs distribution extensions, in RDA Module 2. Would it be preferable to also defer the decision to eliminate the Minimum Connection Charge for 400A service to Module 2, so that the elimination of the Minimum Connection Charge and its replacement with an amendment to section 8 of the Electric Tariff can be discussed at the same time? Why or why not?

RESPONSE:

BC Hydro is proposing elimination of the 400A standard charge for the reasons set out on page 8-7, lines 10 to 16, of Exhibit B-1, primarily to avoid misleading customers as the 400A charge typically requires additional work, and therefore additional costs of construction beyond the charge set out in the Standard Charges.

The 400A charge reflects costs which will not be influenced by updates to the distribution extension provisions. BC Hydro's review of the distribution extension provisions in RDA Module 2 is to review the cost allocation methodology between BC Hydro and the customer, rather than the costs themselves.

119.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.1, pp. 8-6 and 8-7
Minimum connection charges – 400A overhead

BC Hydro submits on page 8-7 of its Application the following:

…due to system requirements 400A service requests often require additional transformation costs that are not included in the Minimum Connection Charge and would often require the creation of a distribution design for the installation which would include additional non-standard charges. To avoid customer confusion, BC Hydro is proposing to eliminate the 400A Minimum Connection Charge and address such service requests through the Distribution extension provisions in section 8 of the Electric Tariff.

1.119.3.1 Should the Commission approve a revised Minimum Connection Charge for 400A service, which would remain in place until such time as an amendment to section 8 of the Electric Tariff is approved? Why or why not?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.119.3.

119.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.1, pp. 8-6 and 8-7
Minimum connection charges – 400A overhead

BC Hydro submits on page 8-7 of its Application the following:

…due to system requirements 400A service requests often require additional transformation costs that are not included in the Minimum Connection Charge and would often require the creation of a distribution design for the installation which would include additional non-standard charges. To avoid customer confusion, BC Hydro is proposing to eliminate the 400A Minimum Connection Charge and address such service requests through the Distribution extension provisions in section 8 of the Electric Tariff.

1.119.4 For F2016, please provide the following information related to 400A service requests:

- Forecast number of service requests; and
- Calculations to support the forecast revenue and costs in the event that the service requests are addressed through a Minimum Connection Charge.

RESPONSE:

F2016	Service Orders	Designs	Total Service Requests	Service Order Charges ($)	Design Charges-Customer Cost ($)	Total ($)
Fiscal Year Actual to Date	85	72	157	67,830	407,554	475,384
Year End Forecast	146	123	269	116,280	698,664	814,944
Average Forecast 400A Cost						3,030

120.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, pp. 1-10
Minimum connection charges – total labour

The Minimum Connection Charges "Basis for Calculation" schedules found in Appendix G-1B of the BC Hydro Application include a loaded SLR of $143.57.

The SLR used in the determination of the Minimum Connection Charges in the 2007 RDA is $65.08.[1]

1.120.1 Please provide supporting calculations for the loaded SLR of $143.57, including a breakdown of the following components: base hourly rate, benefits, concessions and field loading.

RESPONSE:

The breakdown of the $143.57 is as follows:

Base Pay	42.35
Benefits	16.70
Concessions	23.94
Total Loaded Hrly Rate	82.99
Direct Overheads	24.92
Indirect Overheads	35.66
Total Fully Loaded Rate	143.57

Notes:

Direct Overheads include: Tools & Supplies, training, non-productive time (meetings), travel, office supplies, direct management and admin support.

Indirect Overheads include: Management and administrative support functions (HR, Finance), Safety, IT and Properties.

[1] BC Hydro 2007 Rate Design Application, Exhibit B-1, Appendix H. http://www.bcuc.com/ApplicationView.aspx?ApplicationId=145

120.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, pp. 1-10
Minimum connection charges – total labour

The Minimum Connection Charges "Basis for Calculation" schedules found in Appendix G-1B of the BC Hydro Application include a loaded SLR of $143.57.

The SLR used in the determination of the Minimum Connection Charges in the 2007 RDA is $65.08.[1]

1.120.1 Please provide supporting calculations for the loaded SLR of $143.57, including a breakdown of the following components: base hourly rate, benefits, concessions and field loading.

1.120.1.1 Please confirm, or explain otherwise, that the loaded SLR of $143.57 relates to Power Line Technicians only.

RESPONSE:

Confirmed.

[1] BC Hydro 2007 Rate Design Application, Exhibit B-1, Appendix H. http://www.bcuc.com/ApplicationView.aspx?ApplicationId=145

120.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, pp. 1-10
Minimum connection charges – total labour

The Minimum Connection Charges "Basis for Calculation" schedules found in Appendix G-1B of the BC Hydro Application include a loaded SLR of $143.57.

The SLR used in the determination of the Minimum Connection Charges in the 2007 RDA is $65.08.[1]

1.120.1 Please provide supporting calculations for the loaded SLR of $143.57, including a breakdown of the following components: base hourly rate, benefits, concessions and field loading.

1.120.1.2 Please provide the actual loaded SLR for Power Line Technicians for each of F2012, F2013 and F2014.

RESPONSE:

The actual loaded SLR for PLTs for F2012, F2013 and F2014 is provided below.

	Loaded LSR ($)
F2012	**137.48**
F2013	**136.34**
F2014	**142.03**

[1] BC Hydro 2007 Rate Design Application, Exhibit B-1, Appendix H.
http://www.bcuc.com/ApplicationView.aspx?ApplicationId=145

120.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, pp. 1-10
Minimum connection charges – total labour

The Minimum Connection Charges "Basis for Calculation" schedules found in Appendix G-1B of the BC Hydro Application include a loaded SLR of $143.57.

The SLR used in the determination of the Minimum Connection Charges in the 2007 RDA is $65.08.[1]

1.120.2 Please provide the reasons for the 120 percent increase in the SLR from $65.08 in the 2007 RDA to $143.57 in the 2015 RDA.

RESPONSE:

There are two reasons for the increase:

- **The eight-years spanning the 2007 RDA and 2015 RDA, during which time the minimum connection charges were not updated; and**
- **A change in loading methodology on distribution work.**

[1] BC Hydro 2007 Rate Design Application, Exhibit B-1, Appendix H. http://www.bcuc.com/ApplicationView.aspx?ApplicationId=145

121.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, pp. 1 to10
Minimum Connection Charges – vehicle cost

The Minimum Connection Charges "Basis for Calculation" schedules found in Appendix G-1B of the BC Hydro Application include vehicle costs determined as 29 percent of the labour required.

1.121.1 Please provide supporting calculations for the 29 percent of labour required used to determine the vehicle costs with an explanation of the basis for this percentage.

RESPONSE:

The calculations for the 29 per cent is based on the total annual fleet costs for all Distribution line vehicles (this includes cost related to depreciation, fuel, maintenance and insurance) divided by the total productive field worker hours. This results in an average hourly rate of $24/hour which is 29 per cent of the hourly standard labour rate of $82.99.

121.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, pp. 1 to10
Minimum Connection Charges – vehicle cost

The Minimum Connection Charges "Basis for Calculation" schedules found in Appendix G-1B of the BC Hydro Application include vehicle costs determined as 29 percent of the labour required.

1.121.2 Please explain the rationale for using a percentage of labour required to determine the vehicle costs, as opposed to vehicle hourly rate.

RESPONSE:

The vehicle used by a crew varies from location to location, depending on availability at that location (it may be anything from a pick-up truck to a bucket truck, which have very different hourly rates). The percentage of the SLR represents an average hourly vehicle cost ($24.07), which is less than the $45.11 hourly rate for a bucket (aerial) truck which could be used for a 400A OH connection.

121.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, pp. 1 to10
Minimum Connection Charges – vehicle cost

The Minimum Connection Charges "Basis for Calculation" schedules found in Appendix G-1B of the BC Hydro Application include vehicle costs determined as 29 percent of the labour required.

1.121.3 Please provide supporting calculations for the unloaded labour cost and crew cost.

RESPONSE:

The breakdown of the $82.99 is as follows:

Base Pay	**42.35**
Benefits	**16.70**
Concessions	**23.94**
Total Hourly Rate	**82.99**

121.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, pp. 1 to10
Minimum Connection Charges – vehicle cost

The Minimum Connection Charges "Basis for Calculation" schedules found in Appendix G-1B of the BC Hydro Application include vehicle costs determined as 29 percent of the labour required.

1.121.4 For each of: Overhead 100 AMPS; Overhead 200 AMPS; Underground 100 AMPS; Underground 150 – 200 AMPS; First Subsequent Meter Installation; and Service Connection Call-Back Minimum Connection Charges, please provide the following:

- vehicle type used;
- hourly rate for vehicle type used; and
- calculation of vehicle cost input to the Minimum Connection charge using the hourly rate for the vehicle type used.

RESPONSE:

The requested information is provided below.

Service	Vehicle	Hourly Rate ($)	Vehicle Cost for Standard Charge ($)
100A OH	**Bucket truck**	**45.11**	**150.67**
200A OH	**Bucket truck**	**45.11**	**150.67**
100A UG	**UG Van & Trailer**	**21.34**	**75.54**
200A UG	**UG Van & Trailer**	**21.34**	**89.63**
First Meter	**Pickup**	**11.48**	**9.76**
Call Back	**Bucket truck**	**21.34**	**36.90**

122.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, pp. 1-10
Minimum Connection Charges – overhead loadings

The minimum connection charges "Basis for Calculation" schedules found in Appendix G-1B of the BC Hydro Application include an overhead loading of 27 percent.

1.122.1 Please provide supporting calculations for the overhead loadings of 27 percent with an explanation of the basis for this percentage.

RESPONSE:

The 27 per cent overhead loading is the total fully loaded cost of designer's time spent on customer driven work. The breakdown of the 27 per cent is calculated follows:

Designer Costs (%)	**16**
Indirect Overhead Loadings (%)	**6**
Support Overhead Loadings (%)	**5**
Total (%)	**27**

Designer costs includes fully loaded wages, training, materials, travel.

Indirect overhead includes management and administrative support costs.

Support overhead loadings include Human Resources, Finance, Safety, IT and Properties.

123.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.2, pp. 8-7 to 8-11
Minimum Reconnection Charge

On page 8-9 of its Application, BC Hydro lists the circumstances under which manual disconnections or reconnections are required, including when "[t]he premises does not have a meter enabled for [remote disconnect/reconnect (RDR)] (including legacy meters, poly-phase meters and some special metering types)".

On page 8-10 of its Application, BC Hydro submits that it "recently implemented a new process such that accounts are automatically disconnected 21 days after a customer terminates service unless a new customer has applied…Currently, there are approximately 1,000 vacant account disconnections each week, which exceeds the number of non-pay disconnections."

1.123.1 Does "automatically disconnected" for vacant account mean that no costs are incurred or are the disconnection costs absorbed by customers paying the Minimum Reconnection charge?

RESPONSE:

There are incidental costs associated with automated vacant account disconnections because BC Hydro sends two notices to the premises before disconnecting (at $0.83 each). Provided that the remote reconnection is successful, there are no additional costs to reconnect a vacant account because it is accomplished while processing the customer's move-in application.

The proposed Minimum Reconnection Charge excludes these costs and so the costs of vacant account disconnections are not absorbed by customers paying the Minimum Reconnection Charge.

123.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.2, pp. 8-7 to 8-11
Minimum Reconnection Charge

On page 8-9 of its Application, BC Hydro lists the circumstances under which manual disconnections or reconnections are required, including when "[t]he premises does not have a meter enabled for [remote disconnect/reconnect (RDR)] (including legacy meters, poly-phase meters and some special metering types)".

On page 8-10 of its Application, BC Hydro submits that it "recently implemented a new process such that accounts are automatically disconnected 21 days after a customer terminates service unless a new customer has applied…Currently, there are approximately 1,000 vacant account disconnections each week, which exceeds the number of non-pay disconnections."

1.123.1 Does "automatically disconnected" for vacant account mean that no costs are incurred or are the disconnection costs absorbed by customers paying the Minimum Reconnection charge?

1.123.1.1 If the answer to the aforementioned IR is yes, please provide a revised proposed Minimum Reconnection Charge excluding disconnection costs for vacant account disconnections, or other disconnections where there is no reconnection and presumably no Manual Reconnection charge.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.123.1.

124.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, p. 7
Minimum Reconnection Charge

Page 7 of Appendix G-1B to the BC Hydro Application includes the breakdown of the costs included in the proposed Minimum Reconnection charge, for both regular hours and overtime, and the Refused Access Reconnection charge.

1.124.1 For the proposed Minimum Reconnection Charge for both regular hours and overtime, please provide a detailed demonstration of the calculation for each of the following cost inputs:

- ABSBC (Call Centre and Credit Review)
- Manual Disconnection
- Manual Reconnection

RESPONSE:

The requested information is provided as Attachment 1 to this response.

As provided by section 42 of the *ATA* and section 1 of the Commission's Confidential Filings Practice Directive, BC Hydro requests confidential filing with the Commission for those parts of Attachment 1 which relate to ABSBC cost information on the basis that:

- **Such information is financial and commercial information that is confidential and has consistently been treated as confidential by BC Hydro and ABSBC; and**

- **Disclosure of such information could reasonably be expected to result in significant harm or prejudice to ABSBC's competitive or negotiating position.**

A public version of Attachment 1 has been provided, with change made so as not to disclose ABSBC's hourly rates.

Reconnection Charge Summary

Calculation of Average Resource Costs

Standard Rates	Hourly Rate	Min Rate	AHT (min)	Avg Cost	
Credit Review		CONFIDENTIAL		3.79	
Call Center				3.96	
PLT Loaded Rate	143.57	2.39	238.83	571.48	Travel time = 119.42 X 2 (two man PLT crew)
Meter Tech Loaded Rate	116.60	1.94	72.45	140.79	
FMA		CONFIDENTIAL		46.90	
Dispatcher	46.84	0.78	10.00	7.81	
OT Rates					
PLT OT Loaded Rate	171.93	2.87	238.83	684.37	
Meter Tech OT Loaded Rate	132.28	2.20	72.45	159.72	
FMA OT Rate		CONFIDENTIAL		70.35	

Calculation of Reconnection Charge - Standard Time

Reconnection request channels, remote and mannual disconnection and reconnection distributions based on F2015 actuals.

Cost Items	% of Occurrences	Resource Weighting	Weighted Resource Cost	Standard Time
Agent				
Credit Review	100%			$ 3.79
Call Centre	40%			$ 1.58
Manual Disconnect/Reconnect				
Disconnection				
PLT		16%	$ 93.12	
Meter Tech		43%	$ 60.52	
FMA		41%	$ 19.10	
Dispatcher		100%	$ 7.81	
Weighted Average Cost	5%		$ 180.54	$ 9.48
Reconnection				
PLT		24%	$ 138.10	
Meter Tech		44%	$ 61.33	
FMA		32%	$ 15.14	
Dispatcher		100%	$ 7.81	
Weighted Average Cost	7%		$ 222.38	$ 14.95
Fee per non-pay reconnection				**$ 29.80**
Rounded				**$ 30**

Calculation of Reconnection Charge - Overtime

1. Disconnection cost based on weighted average of remote/manual during regular hours.
2. Reconnection costs based on 100% manual during after hours (OT labour rates applied).

Cost Items	% of Occurrences	Resource Weighting	Weighted Resource Cost	Overtime
Agent				
Credit Review	100%			$ 3.79
Call Centre	40%			$ 1.58
Manual Disconnect/Reconnect				
Disconnection				
PLT		16%	$ 93.12	
Meter Tech		43%	$ 60.52	
FMA		41%	$ 19.10	
Dispatcher		100%	$ 7.81	
Weighted Average Cost	5%		$ 180.54	$ 9.48
Reconnection				
PLT		24%	$ 165.38	
Meter Tech		44%	$ 69.58	
FMA		32%	$ 22.70	
Dispatcher		100%	$ 7.81	
Weighted Average Cost	100%		$ 265.47	$ 265.47
Fee per non-pay reconnection				**$ 280.32**
	Rounded			**$ 280**

Calculation of Reconnection Charge - Refused Access

1. Refused access disconnection and reconnection are always performed by two-man PLT crew.
2. Average travel time remains the same in the meter tech and FMA service areas.

Cost Items	% of Occurrences	Resource Weighting	Weighted Resource Cost	Overtime	
Agent					
Credit Review	100%			$ 3.79	
Call Centre	100%			$ 11.87	100% handled by Call Centre, 3 calls per customer
Manual Disconnect/Reconnect					
Disconnection					
PLT		16%	$ 93.12		
PLT in Meter Tech area		43%	$ 149.03		
PLT in FMA area		41%	$ -		
Dispatcher		100%	$ 7.81		
Weighted Average Cost	100%		$ 249.95	$ 249.95	
Reconnection					
PLT		24%	$ 138.10		
PLT in Meter Tech area		44%	$ 151.03		
PLT in FMA area		32%	$ -		
Dispatcher		100%	$ 7.81		
Weighted Average Cost	100%		$ 296.94	$ 296.94	
Fee per non-pay reconnection				**$ 562.55**	
	Rounded			**$ 700**	

124.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, p. 7
Minimum Reconnection Charge

Page 7 of Appendix G-1B to the BC Hydro Application includes the breakdown of the costs included in the proposed Minimum Reconnection charge, for both regular hours and overtime, and the Refused Access Reconnection charge.

1.124.1.1 Please identify the changes in the methodology used to calculate the proposed Minimum Reconnection Charge as compared to the methodology used to calculate the charge put forward in the 2007 BC Hydro RDA.

RESPONSE:

The methodology in the 2007 RDA was essentially to take a 'top down' approach using actual data from F2006:

- **The total cost of labour and vehicles performing manual disconnections and reconnections was divided by the volume of disconnections;**
- **Additional charges for overtime and call out reconnections were based on weightings of costs and volumes as compared to those performed during regular hours; and**
- **Other costs such as call centre agent time were considered incidental and were not included in the calculation.**

The introduction of RDR changed the cost profile of the Minimum Reconnection Charge. While the costs of manually disconnecting and reconnecting services remain high, these activities are now performed relatively infrequently. As a result, the cost of collection and call centre agent time is now more significant.

The 2015 RDA methodology uses a 'bottom up' approach by calculating the weighted average cost of a single disconnection/reconnection:

- **The unit cost of each activity was calculated using the most appropriate method given its nature. This recognizes that using historical costs and volumes are not always relevant given the recent transition to RDR;**
- **Recognizing that multiple resource types can perform a manual disconnection or reconnection, weightings were applied based on the frequency of occurrence in F2015 to develop an overall average cost to perform a manual disconnection or reconnection; and**

- **A weighted average cost was calculated that considered the frequency of occurrence for the identified activities.**

For reconnections performed on overtime at the customer's request, the standard charge includes the full cost of dispatching a resource outside of regular working hours for the reconnection. The remainder of the calculation is the same as in the derivation of the Minimum Reconnection Charge.

124.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, p. 7
Minimum Reconnection Charge

Page 7 of Appendix G-1B to the BC Hydro Application includes the breakdown of the costs included in the proposed Minimum Reconnection charge, for both regular hours and overtime, and the Refused Access Reconnection charge.

1.124.2 For the proposed Refused Access Reconnection charge, please provide a detailed demonstration of the calculation for each of the following cost inputs:

- ABSBC (Call Centre and Credit Review)
- Manual Disconnection
- Manual Reconnection

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.124.1.

124.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, p. 7
Minimum Reconnection Charge

Page 7 of Appendix G-1B to the BC Hydro Application includes the breakdown of the costs included in the proposed Minimum Reconnection charge, for both regular hours and overtime, and the Refused Access Reconnection charge.

1.124.2.1 Please identify the changes in the methodology used to calculate the proposed Refused Access Reconnection Charge as compared to the methodology used to calculate the charge put forward in the 2007 BC Hydro RDA.

RESPONSE:

The 2007 RDA did not include a Refused Access Reconnection charge.

As described in BC Hydro's response to BCUC IR 1.124.1.1, the proposed methodology is to charge the full cost of the PLT crew and vehicle required to perform the disconnection and reconnection at the service connection as well as the additional Call Centre costs.

125.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3, Table 8-4, p. 8-12; Appendix C-3A, pp. 93-94
Late Payment Charge - $30 Threshold

In Table 8-4 on page 8-12 of the Application, BC Hydro provides a jurisdictional comparison of other Canadian electric utilities' late payment charges.

1.125.1 Please indicate whether any of these Canadian electric utilities also have a threshold for application of the Late Payment Charge, and if so, what the threshold is for each utility.

RESPONSE:

New Brunswick Power does not assess a Late Payment Charge unless the Late Payment Charge is a minimum of $0.50. At a rate of 1.25 per cent, this equals a minimum outstanding balance of $40.

BC Hydro is not aware of other Canadian electric utilities that have a threshold for application of a Late Payment Charge.

125.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3, Table 8-4, p. 8-12; Appendix C-3A, pp. 93-94
Late Payment Charge - $30 Threshold

On page 94 of Appendix C-3A, BC Hydro states: "The expected revenue impact of assessing a late payment charge for accounts with less than $30 owing is estimated to be less than $100,000 per year (the late payment charge revenue is estimated to be $7.5 million for F2015)."

1.125.2 Please provide a detailed calculation of the $100,000 revenue impact and explain all inputs and assumptions.

RESPONSE:

BC Hydro does not have periodic reporting of accounts with less than $30 owning. As a result, the estimate was based on a snapshot of accounts in arrears and then extrapolated to determine the magnitude of potential revenue.

On December 2, 2015, BC Hydro had 34,769 accounts with outstanding balances below the $30 threshold, totalling $420,267. Based on this figure, the estimated revenue not being recovered because of the $30 threshold for application of the Late Payment Charge is as follows:

Balance in Arrears ($)	Late Payment Charge (%)	Potential Monthly Revenue ($)	Number of Months	Total Estimated Revenue Impact ($)
A	B	C=AxB	D	E=CxD
420,267	1.5	6,304	12	75,648

125.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3, Table 8-4, p. 8-12; Appendix C-3A, pp. 93-94
Late Payment Charge - $30 Threshold

On page 94 of Appendix C-3A, BC Hydro states: "The expected revenue impact of assessing a late payment charge for accounts with less than $30 owing is estimated to be less than $100,000 per year (the late payment charge revenue is estimated to be $7.5 million for F2015)."

1.125.3 Please provide a detailed calculation of the additional cost to BC Hydro of assessing a late payment charge for accounts below the $30 threshold. Please explain all inputs and assumptions.

RESPONSE:

For context, the Late Payment Charge for an account with a $30 outstanding balance is $0.45 per month (i.e., $30 times 0.015).

The application of the Late Payment Charge is linked to the Dunning process in that the $30 threshold is also used as the trigger to send a Late Payment Notice. The current cost of printing and sending a letter is $0.89. Therefore, an overdue balance has to be greater than $59 (i.e., $0.89 divided by 0.015) for the Late Payment Charge to be sufficient to recover the cost of the letter.

BC Hydro also expects that removing the $30 threshold would decrease customer satisfaction and increase the number of calls to the call centre to inquire as to the reason for the charge or request it to be reversed. The cost of a typical call is much greater than the $0.45 maximum revenue from removing the threshold.

125.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3, Table 8-4, p. 8-12; Appendix C-3A, pp. 93-94
Late Payment Charge - $30 Threshold

BC Hydro states on page 93 of Appendix C-3A that it "undertook a high-level analysis of its accounts receivable reporting for outstanding balances of less than $30 that are overdue between 30 and 60 days."

1.125.4 Please provide the percentage of total late payments that were less than the $30 threshold during F2015.

RESPONSE:

Historical account balance information is not available. Twenty-six per cent of active accounts in arrears on December 2, 2015 had outstanding balances of less than $30.

When expressed in dollars, these accounts comprised 2 per cent of the total outstanding balance in arrears.

126.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.3, Tables 8-4 and 8-5, pp. 8-11 to 8-14 Late Payment Charge

In Table 8-4 on page 8-12 of the Application, BC Hydro provides a jurisdictional comparison of other Canadian electric utilities' late payment charges.

In Table 8-5 on page 8-13 of the Application, BC Hydro provides the cost breakdown for the 1.5 percent Late Payment Charge, which includes $1,968,415 of BC Hydro interest at its most recent Weighted Average Cost of Debt (WACD).

1.126.1 Please provide the type of carrying charge applied to late payment charges by each of the utilities listed in Table 8-4 (i.e. short-term interest rate, WACD, or other).

RESPONSE:

BC Hydro does not have information about how each of the utilities derived its late payment charges and so is unable to provide a response.

126.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.3, Tables 8-4 and 8-5, pp. 8-11 to 8-14 Late Payment Charge

In Table 8-4 on page 8-12 of the Application, BC Hydro provides a jurisdictional comparison of other Canadian electric utilities' late payment charges.

In Table 8-5 on page 8-13 of the Application, BC Hydro provides the cost breakdown for the 1.5 percent Late Payment Charge, which includes $1,968,415 of BC Hydro interest at its most recent Weighted Average Cost of Debt (WACD).

1.126.2 Please explain the rationale for applying WACD to late payment charges as opposed to short-term interest.

RESPONSE:

Decreases in internally-generated financial resources must be replaced by alternate sources. At the margin, BC Hydro finances its operations through a mix of short-term and long-term debt instruments. However, as a capital-intensive company, BC Hydro's borrowing costs are more reflective of long-term interest rates than short-term rates. WACD is a well published rate and used in a number of interest bearing calculations (i.e., regulatory account balances) and so is an appropriate measure of borrowing costs related to late payments.

In addition, there should be consistency between the borrowing cost component of the Late Payment Charge calculation and the interest rate paid on security deposits, as both are related to revenue collection. WACD is currently used to calculate interest paid on security deposits held by BC Hydro.

If the Commission were to determine that short-term interest rates should be applied when calculating the Late Payment Charge, BC Hydro also submits that a short-term rate should also be used for interest paid on security deposits, as was noted in section 8.3.3 of Exhibit B-1:

- **WACD provides a financial incentive to customers to be late on their payments so as to enjoy a deposit rate they cannot get elsewhere, and also increases the costs of securing accounts against non-payment;**
- **Amendments to existing Electric Tariff section 2.4.4.(6) would be required - currently, interest in security deposits "at rate equal to BC Hydro's [WACD]"; and to section 11.3 as the Late Payment Charge would reduce from 1.5 per cent to 1.25 per cent;**

- **As stated in section 1.2.2 of the Workshop 9a/9b consideration memo, Appendix C-3B, page 307 of 609, moving from a 1.5 per cent late payment charge to 1.25 per cent would have reduced F2015 revenue by approximately $1.3 million (from $7.8 to $6.5 million); and**

- **A reduction in the interest rate applied to security deposits would have reduced associated interest expenses in F2015 from $1.86 million to $0.3 million, which offsets the loss in late payment charge revenues.**

BC Hydro notes that the OEB Low Income Customer Rules specify the interest paid on security deposits as being equal to the Bank of Canada's prime business rate less 2 per cent.

126.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.3, Tables 8-4 and 8-5, pp. 8-11 to 8-14 Late Payment Charge

In Table 8-4 on page 8-12 of the Application, BC Hydro provides a jurisdictional comparison of other Canadian electric utilities' late payment charges.

In Table 8-5 on page 8-13 of the Application, BC Hydro provides the cost breakdown for the 1.5 percent Late Payment Charge, which includes $1,968,415 of BC Hydro interest at its most recent Weighted Average Cost of Debt (WACD).

1.126.2.1 Which type of carrying charge does BC Hydro view as more reflective of how it finances costs related to late payment charges? Please discuss.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.126.2.

126.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.3, Tables 8-4 and 8-5, pp. 8-11 to 8-14 Late Payment Charge

BC Hydro provides a breakdown of the Late Payment Charge costs in Table 8-5.

1.126.3 Please provide a more detailed breakdown and description of the Customer Late Payment Communications cost of $1,949,170, including how much of this cost is related to labour versus non-labour.

RESPONSE:

The Customer Late Payment Communications cost is comprised of the direct cost of printing and postage associated with automated collections letters. There is no labour included in this figure.

The $1,949,170 figured was based on a volume of 1,949,170 letters sent in F2015 at an estimated cost of $1 each. Upon further review of the associated costing, BC Hydro identified that its F2015 letter printing and postage cost was $1,696,145. With this revision, the total Dunning costs associated with the Late Payment Charge as shown in Table 8-5 of Exhibit B-1 is $7,795,704.

126.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.3, Tables 8-4 and 8-5, pp. 8-11 to 8-14 Late Payment Charge

BC Hydro provides a breakdown of the Late Payment Charge costs in Table 8-5.

1.126.3.1 For the labour component of the cost, please describe the inputs comprising the cost, including number of labour hours and cost per labour hour.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.126.3.

126.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.3, Tables 8-4 and 8-5, pp. 8-11 to 8-14 Late Payment Charge

BC Hydro provides a breakdown of the Late Payment Charge costs in Table 8-5.

1.126.4 Please provide a more detailed breakdown and description of the $250,000 O&M costs.

RESPONSE:

This figure is a high-level estimate of BC Hydro labour involved in collections activities. It includes the following:

- **One full-time Performance Manager, Payments and Collections;**
- **One-quarter time of a Senior Treasury Portfolio Manager; and**
- **One-quarter time of a Customer Relations Manager.**

Other notable costs also include Legal and IT, as well as by BC Hydro management for significant collections issues.

127.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.4, pp. 8-14 and 8-15; Appendix G-1B, p. 9
Returned Payment Charge

Page 9 of Appendix G-1B shows the calculation of the Returned Payment Charge, including the total number of returned payments of 11,892.

1.127.1 Please compare the total number of returned payments in F2015 to the total number of returned payments in F2006 (i.e. at the time of filing BC Hydro's 2007 RDA). Please also indicate how many of these returned payments in F2006 were returned cheques and how many were returned EFTs.

RESPONSE:

F2015 Returned Payments: 11,892 (1,045 cheques; 11,892 EFTs).

F2006 Returned Payments: 11,648 (4,013 cheques; 7,635 EFTs).

127.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.4, pp. 8-14 and 8-15; Appendix G-1B, p. 9
Returned Payment Charge

Page 9 of Appendix G-1B shows the calculation of the Returned Payment Charge, including the total number of returned payments of 11,892.

1.127.2 Please provide the fee charged by BC Hydro's bank for failed electronic payments as compared to failed cheques.

RESPONSE:

Please refer to Attachment 1 to this response for the requested information.

As provided by section 42 of the *ATA* and section 1 of the Commission's Confidential Filings Practice Directive, BC Hydro requests confidential filing with the Commission for the requested bank-related cost information on the basis that such information is the subject of contractual obligations, and is financial and commercial information that is confidential and has consistently been treated as confidential by BC Hydro and its bank.

BC Hydro also requests confidential filing with the Commission for ABSBC-related cost information on the basis that:

- **Such information is financial and commercial information that is confidential and has consistently been treated as confidential by BC Hydro and ABSBC; and**
- **Disclosure of such information could reasonably be expected to result in significant harm or prejudice to ABSBC's competitive or negotiating position.**

CONFIDENTIAL ATTACHMENT

FILED WITH BCUC ONLY

127.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.4, pp. 8-14 and 8-15; Appendix G-1B, p. 9
Returned Payment Charge

Page 9 of Appendix G-1B shows the calculation of the Returned Payment Charge, including the total number of returned payments of 11,892.

1.127.3 Please provide the supporting calculations and explain all inputs and assumptions for each of the following charges comprising the Returned Payment charge:

- • BMO and Symcor Charges - $1.37;
- • ABSBC Handling Cost - $3.68; and
- • Customer Communication (Letter) - $1.00

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.127.2.

127.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.4, pp. 8-14 and 8-15; Appendix G-1B, p. 9
Returned Payment Charge

Page 9 of Appendix G-1B shows the calculation of the Returned Payment Charge, including the total number of returned payments of 11,892.

1.127.4 What is the revenue impact of decreasing the Returned Payment Charge from the current charge of $20 to the proposed charge of $6? Please show all supporting calculations and explain all assumptions.

RESPONSE:

In F2015, the Returned Payment Charge was assessed 6,472 times. Assuming this volume remains consistent, a $14 decrease in the charge (i.e., from $20 to $6) will reduce revenue by $90,608.

127.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.4, pp. 8-14 and 8-15; Appendix G-1B, p. 9
Returned Payment Charge

Page 9 of Appendix G-1B shows the calculation of the Returned Payment Charge, including the total number of returned payments of 11,892.

1.127.5 Please confirm, or explain otherwise, that if BC Hydro continued to use the NSF charge as a proxy for the Returned Payment Charge that it would be recovering an amount from customers that is higher than BC Hydro's actual costs related to this charge.

RESPONSE:

Confirmed.

128.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.5, pp. 8-15 and 8-16; Appendix C-3A, pp. 97 to98; Appendix G-1B, p. 8
Account Charge

On page 8 of Appendix G-1B, BC Hydro provides the following information for the Account Charge:

- Total costs of setting up new accounts - $3,833,057
- Total cost of setting up new account per customer - $12.55

1.128.1 Please confirm, or explain otherwise, that the $12.55 cost provided in the preamble above includes both the cost of setting up a new account as well as the cost for an existing customer to move an account.

RESPONSE:

As provided by section 42 of the *ATA* and section 1 of the Commission's Confidential Filings Practice Directive, BC Hydro requests confidential filing with the Commission for those parts of this IR response which relate to ABSBC and Equifax cost information on the basis that:

- **Such information is financial and commercial information that is confidential and has consistently been treated as confidential by BC Hydro, Equifax and ABSBC; and**

- **Disclosure of such information could reasonably be expected to result in significant harm or prejudice to ABSBC's and Equifax competitive or negotiating position.**

A public version of this response has been provided with modifications made so as not to publicly release detailed ABSBC and Equifax cost information.

The Account Charge is a weighted average of costs incurred in setting up a new account in both of the following situations:

- **The customer is new to BC Hydro and is setting up an account for the first time; and**

- **The customer has had a BC Hydro account and is setting up a new account.**

In F2015, 305,522 accounts were set-up:

- **108,835 (36 per cent) were new customers; and**
- **196,687 (64 per cent) were existing customers setting up a new account.**

Accounts can be set up by a call centre agent or online. In F2015:

- **250,528 (82 per cent) were processed by call centre agents for customers phoning the call centre; and**
- **54,994 (18 per cent) were processed by customers using online self-service tools.**

There are four primary operational costs that are recovered through the Account Charge:

- **ABSBC call centre costs, for all customers setting up the account through the call centre;**
- **Billing and credit costs, for processing security deposit requests or resolve move-in date disputes;**
- **Equifax credit checks, for all new customers that cannot provide an acceptable reference to demonstrate creditworthiness; and**
- **Equifax Identify Validation, with is a new action to be applied to all new customers starting in late F2016 or early F2017.**

The unit costs of each action are as follows. The maximum cost is $18.03 for a new customer setting up an account by a call centre agent.

	Unit Cost
Accenture ($)	**13.83**
Equifax	**4.20**
Total ($)	**18.03**

The approximate unit costs of the four different scenarios (i.e., new vs. existing customer; agent vs. online) are shown below. Weighted average costs are shown for each scenario, as well as the overall weighted average of $12.55.

	Agent ($)	Online ($)	Weighted Average ($)
New Customer	**18.03**	**4.09**	**15.17**
Existing Customer	**13.40**	**0.54**	**11.10**
Weighted Average	**15.02**	**1.92**	**12.55**

As shown, the biggest factor affecting cost is the choice of agent or online channel. There is also a differential between new and existing customers, but it is less significant.

One alternative to a single Account Charge would be to differentiate the Account Charge between new and existing customers, as the credit check and ID validation are actions performed only for new customers. However, the cost differential is relatively small given the frequency that customers move. Also, BC Hydro would require IT investment as well as administration costs to enable this; as IT costs are not typically included in Standard Charges, those costs would be incurred by all customers.

Another alternative would be to differentiate the Account Charge based on choice of channel, as accounts setup online have a significantly lower cost than those setup through the call centre. BC Hydro would be supportive of such an approach because providing a cost signal to encourage online processing would encourage customers to subscribe to paperless billing and use MyHydro for other account transactions, which would help to reduce customer service costs overall.

128.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.5, pp. 8-15 and 8-16; Appendix C-3A, pp. 97 to98; Appendix G-1B, p. 8
Account Charge

BC Hydro states the following on pages 8-15 and 8-16 of the Application:

Costs have increased since the 2007 RDA because of general increases in labour charges as the result of inflation and by the introduction and use of Identity Validation software for new accounts to mitigate bad debt costs resulting from accounts being created in fraudulent names. However, the increase has been mostly offset by a shift towards applications being received through lower-cost online tools. [emphasis added]

BC Hydro states on page 8-16 of the Application:

In Workshop 3, BC Hydro requested feedback on the potential to utilize a differentiated charge on the basis of the application being processed online versus agent, as well as a new customer account versus a move of an existing customer…BC Hydro is not proposing these differentiated charges. Instead, BC Hydro proposes to continue the existing method for determining the Account Charge.

BC Hydro further states in section 1.4.2 of the Workshop 3 consideration memo:

The online service is fairly new and some customers may be disadvantaged by not having internet access…Based on initial analysis, BC Hydro estimates a savings of $300,000 with online move processing. These and additional savings from increased use of self-service options will be reflected in the analysis of moving and account set-up costs.

1.128.2 Based on the above preambles, is it fair to conclude that the largest driver of increased costs is due to new customer accounts as opposed to the moving of existing customer accounts? Please discuss.

RESPONSE:

The largest cost increases at an activity level are Equifax charges for credit checks and the new ID validation. These are incurred only for new customers.

Agent costs have also increased on a per-unit basis, which affects both new and existing customers.

128.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.5, pp. 8-15 and 8-16; Appendix C-3A, pp. 97 to98; Appendix G-1B, p. 8
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BC Hydro further states in section 1.4.2 of the Workshop 3 consideration memo:

The online service is fairly new and some customers may be disadvantaged by not having internet access…Based on initial analysis, BC Hydro estimates a savings of $300,000 with online move processing. These and additional savings from increased use of self-service options will be reflected in the analysis of moving and account set-up costs.

1.128.3 Based on the above preambles, is it also fair to conclude that the largest driver of cost savings is due to online processing of applications from existing customers who are moving accounts? Please discuss.

RESPONSE:

Yes, the largest cost saving in the Account Charge is due to online processing of move-ins. The shift to online processing significantly reduced overall call centre costs associated with move-in transactions.

Both new and existing customers can process their account set up online. Online move in applications from both new and existing customers are subject to the same credit review process and criteria. Security deposits are assessed for customers that do not have satisfactory credit or payment history.

Online account setup also provides future cost savings opportunities because it requires the customer to establish an online profile, which is a precursor to enabling electronic billing and communications.

128.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.5, pp. 8-15 and 8-16; Appendix C-3A, pp. 97 to98; Appendix G-1B, p. 8
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BC Hydro states on page 8-16 of the Application:

In Workshop 3, BC Hydro requested feedback on the potential to utilize a differentiated charge on the basis of the application being processed online versus agent, as well as a new customer account versus a move of an existing customer…BC Hydro is not proposing these differentiated charges. Instead, BC Hydro proposes to continue the existing method for determining the Account Charge.

BC Hydro further states in section 1.4.2 of the Workshop 3 consideration memo:

The online service is fairly new and some customers may be disadvantaged by not having internet access…Based on initial analysis, BC Hydro estimates a savings of $300,000 with online move processing. These and additional savings from increased use of self-service options will be reflected in the analysis of moving and account set-up costs.

1.128.4 If BC Hydro utilized a differentiated charge on the basis of new customer accounts versus the moving of existing customers' accounts, what would the differentiated charges be? Please provide all supporting calculations for these charges and explain all assumptions made.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.128.1.

128.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.5, pp. 8-15 and 8-16; Appendix C-3A, pp. 97 to98; Appendix G-1B, p. 8
Account Charge

BC Hydro states the following on pages 8-15 and 8-16 of the Application:

Costs have increased since the 2007 RDA because of general increases in labour charges as the result of inflation and by the <u>introduction and use of Identity Validation software for new accounts</u> to mitigate bad debt costs resulting from accounts being created in fraudulent names. However, the increase has been mostly offset by a shift towards applications being received through lower-cost online tools. [emphasis added]

BC Hydro states on page 8-16 of the Application:

In Workshop 3, BC Hydro requested feedback on the potential to utilize a differentiated charge on the basis of the application being processed online versus agent, as well as a new customer account versus a move of an existing customer…BC Hydro is not proposing these differentiated charges. Instead, BC Hydro proposes to continue the existing method for determining the Account Charge.

BC Hydro further states in section 1.4.2 of the Workshop 3 consideration memo:

The online service is fairly new and some customers may be disadvantaged by not having internet access…Based on initial analysis, BC Hydro estimates a savings of $300,000 with online move processing. These and additional savings from increased use of self-service options will be reflected in the analysis of moving and account set-up costs.

1.128.5 If BC Hydro utilized a differentiated charge on the basis of the application being processed online versus through an agent, what would the differentiated charges be? Please provide all supporting calculations for these charges and explain all assumptions made.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.128.1.

128.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.5, pp. 8-15 and 8-16; Appendix C-3A, pp. 97 to98; Appendix G-1B, p. 8
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BC Hydro states the following on pages 8-15 and 8-16 of the Application:

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In Workshop 3, BC Hydro requested feedback on the potential to utilize a differentiated charge on the basis of the application being processed online versus agent, as well as a new customer account versus a move of an existing customer…BC Hydro is not proposing these differentiated charges. Instead, BC Hydro proposes to continue the existing method for determining the Account Charge.

BC Hydro further states in section 1.4.2 of the Workshop 3 consideration memo:

The online service is fairly new and some customers may be disadvantaged by not having internet access…Based on initial analysis, BC Hydro estimates a savings of $300,000 with online move processing. These and additional savings from increased use of self-service options will be reflected in the analysis of moving and account set-up costs.

1.128.6 Please explain why it is fair to charge existing customers who move accounts the same amount as new customers. Please incorporate a discussion of the Bonbright principles as part of the explanation.

RESPONSE:

In the context of the Bonbright criteria, the criterion that prevails is practicality. BC Hydro determined that the IT requirements for a differentiated account charge for new customers, versus existing customers who move, would be more than originally thought. For example, configuring the billing system to distinguish between a new customer and an existing customer during the online move-in process would be challenging, in light of name changes, name variations, and gaps in service.

128.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.5, pp. 8-15 and 8-16; Appendix C-3A, pp. 97 to98; Appendix G-1B, p. 8
Account Charge

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BC Hydro states on page 8-16 of the Application:

In Workshop 3, BC Hydro requested feedback on the potential to utilize a differentiated charge on the basis of the application being processed online versus agent, as well as a new customer account versus a move of an existing customer…BC Hydro is not proposing these differentiated charges. Instead, BC Hydro proposes to continue the existing method for determining the Account Charge.

BC Hydro further states in section 1.4.2 of the Workshop 3 consideration memo:

The online service is fairly new and some customers may be disadvantaged by not having internet access…Based on initial analysis, BC Hydro estimates a savings of $300,000 with online move processing. These and additional savings from increased use of self-service options will be reflected in the analysis of moving and account set-up costs.

1.128.7 Please compare the F2015 fees paid to Equifax for credit checks and ID validation of $442,804 (Appendix G-1B, page 8) to the F2006 Equifax fees provided in the BCH 2007 RDA. Please explain the causes/drivers of the increased fees.

RESPONSE:

The Equifax credit check cost increased from $60,529 from F2006 to $127,183 in the F2015. The largest cost increase drivers were the transaction volume increase and contract price inflation.

The remainder of the Equifax cost ($315,622) is the estimated cost for the ID validation that BC Hydro plans to implement in F2016 or early F2017.

128.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.5, pp. 8-15 and 8-16; Appendix C-3A, pp. 97 to98; Appendix G-1B, p. 8
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BC Hydro states the following on pages 8-15 and 8-16 of the Application:

Costs have increased since the 2007 RDA because of general increases in labour charges as the result of inflation and by the introduction and use of Identity Validation software for new accounts to mitigate bad debt costs resulting from accounts being created in fraudulent names. However, the increase has been mostly offset by a shift towards applications being received through lower-cost online tools. [emphasis added]

BC Hydro states on page 8-16 of the Application:

In Workshop 3, BC Hydro requested feedback on the potential to utilize a differentiated charge on the basis of the application being processed online versus agent, as well as a new customer account versus a move of an existing customer…BC Hydro is not proposing these differentiated charges. Instead, BC Hydro proposes to continue the existing method for determining the Account Charge.

BC Hydro further states in section 1.4.2 of the Workshop 3 consideration memo:

The online service is fairly new and some customers may be disadvantaged by not having internet access…Based on initial analysis, BC Hydro estimates a savings of $300,000 with online move processing. These and additional savings from increased use of self-service options will be reflected in the analysis of moving and account set-up costs.

1.128.7 Please compare the F2015 fees paid to Equifax for credit checks and ID validation of $442,804 (Appendix G-1B, page 8) to the F2006 Equifax fees provided in the BCH 2007 RDA. Please explain the causes/drivers of the increased fees.

1.128.7.1 What costs are included in the $442,804? Is this a flat fee charged by Equifax? Please explain.

RESPONSE:

The Equifax costs include two major components:

1. Credit check - $127,183

Equifax credit checks are charged on a per-transaction basis. Different types of transactions (e.g., internet, verbal inquiry, international) have different unit prices. However, the majority of transactions were individual file checks processed through the internet.

2. ID validation - $315,622

ID validation is also charged on a per-transaction basis. This is the estimated price based on quotes from Equifax, multiplied by BC Hydro's forecast of new accounts that would be subject to ID validation.

128.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.5, pp. 8-15 and 8-16; Appendix C-3A, pp. 97 to98; Appendix G-1B, p. 8
Account Charge

BC Hydro states the following on pages 8-15 and 8-16 of the Application:

Costs have increased since the 2007 RDA because of general increases in labour charges as the result of inflation and by the introduction and use of Identity Validation software for new accounts to mitigate bad debt costs resulting from accounts being created in fraudulent names. However, the increase has been mostly offset by a shift towards applications being received through lower-cost online tools. [emphasis added]

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1.128.8 Are the Equifax costs of $442,804 mainly attributable to new customer accounts? Please explain.

RESPONSE:

Yes, credit checks and ID validation are performed almost exclusively for new customers.

128.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.5, pp. 8-15 and 8-16; Appendix C-3A, pp. 97 to98; Appendix G-1B, p. 8
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BC Hydro states the following on pages 8-15 and 8-16 of the Application:

Costs have increased since the 2007 RDA because of general increases in labour charges as the result of inflation and by the introduction and use of Identity Validation software for new accounts to mitigate bad debt costs resulting from accounts being created in fraudulent names. However, the increase has been mostly offset by a shift towards applications being received through lower-cost online tools. [emphasis added]

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BC Hydro further states in section 1.4.2 of the Workshop 3 consideration memo:

The online service is fairly new and some customers may be disadvantaged by not having internet access…Based on initial analysis, BC Hydro estimates a savings of $300,000 with online move processing. These and additional savings from increased use of self-service options will be reflected in the analysis of moving and account set-up costs.

1.128.9 Please provide a more detailed explanation and breakdown of the $3,390,253 "ABSBC costs related to processing application for service."

RESPONSE:

The $3,390,253 ABSBC cost includes two components:

1. Call centre - $3,224,593

This is the ABSBC call centre contract cost multiplied by the percentage of total call time spent on processing move in applications.

2. Credit team – $165,660

This is the number of move in applications that were escalated to the credit team to review (25,750) multiplied by the average handle time spent on each review, and multiplied by the contracted hourly rate.

128.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.5, pp. 8-15 and 8-16; Appendix C-3A, pp. 97 to98; Appendix G-1B, p. 8
Account Charge

BC Hydro states the following on pages 8-15 and 8-16 of the Application:

Costs have increased since the 2007 RDA because of general increases in labour charges as the result of inflation and by the <u>introduction and use of Identity Validation software for new accounts</u> to mitigate bad debt costs resulting from accounts being created in fraudulent names. However, the increase has been mostly offset by a shift towards applications being received through lower-cost online tools. [emphasis added]

BC Hydro states on page 8-16 of the Application:

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BC Hydro further states in section 1.4.2 of the Workshop 3 consideration memo:

The online service is fairly new and some customers may be disadvantaged by not having internet access…Based on initial analysis, BC Hydro estimates a savings of $300,000 with online move processing. These and additional savings from increased use of self-service options will be reflected in the analysis of moving and account set-up costs.

1.128.9 Please provide a more detailed explanation and breakdown of the $3,390,253 “ABSBC costs related to processing application for service.”

1.128.9.1 Please confirm, or explain otherwise, that the $300,000 estimated cost savings from online processing has been reflected in the “ABSBC costs related to processing application for service” of $3,390,253.

RESPONSE:

Confirmed.

128.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1: Section 8.3.5, pp. 8-15 and 8-16; Appendix C-3A, pp. 97 to98; Appendix G-1B, p. 8
Account Charge

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Costs have increased since the 2007 RDA because of general increases in labour charges as the result of inflation and by the <u>introduction and use of Identity Validation software for new accounts</u> to mitigate bad debt costs resulting from accounts being created in fraudulent names. However, the increase has been mostly offset by a shift towards applications being received through lower-cost online tools. [emphasis added]

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In Workshop 3, BC Hydro requested feedback on the potential to utilize a differentiated charge on the basis of the application being processed online versus agent, as well as a new customer account versus a move of an existing customer…BC Hydro is not proposing these differentiated charges. Instead, BC Hydro proposes to continue the existing method for determining the Account Charge.

BC Hydro further states in section 1.4.2 of the Workshop 3 consideration memo:

The online service is fairly new and some customers may be disadvantaged by not having internet access…Based on initial analysis, BC Hydro estimates a savings of $300,000 with online move processing. These and additional savings from increased use of self-service options will be reflected in the analysis of moving and account set-up costs.

1.128.10 Of the 305,522 applications for service in F2015, how many of these were for new customer accounts as opposed to existing customers moving accounts?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.128.1.

129.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.6, pp. 8-16 and 8-17
Proposed Meter Test charge

On page 8-17 of its Application, BC Hydro identifies 3 options for the Meter Test charge:

- Option 1 – the updated default Minimum Reconnection Charge 1 of $30;
- Option 2 – the updated Minimum Connection Charge (First Meter) of $181 to more closely reflect cost recovery; and
- Option 3 – the current (not updated) default Minimum Reconnection Charge of $125.

With respect to the options for the proposed Meter Test charge, BC Hydro submits on page 8-17 of its Application that "COPE 378 expressed concern that both option 2 and option 3 may result in some customers with legitimate concerns foregoing their right to have the meter tested out of concern they would be charged if the meter passes."

BC Hydro further submits on page 8-17 of the Application that it "agrees with BCOAPO and FNEMC that option 2 is preferable because it provides full cost recovery."

1.129.1 What is BC Hydro's response COPE 378's concern discussed on page 8-17 of the Application? Please discuss.

RESPONSE:

BC Hydro responded to COPE 378's concern in section 1.4.2 of the Workshop 9a/9b consideration memo (Exhibit B-1, Appendix C-3B, page 311 of 609). BC Hydro expands on that response in this IR. In addition to Option 1 significantly under-recovering its costs, BC Hydro is concerned that a $30 Meter Test charge does not provide a sufficient price signal to deter customers from unnecessary testing.

BC Hydro supports a customer's right to ask for a meter to be tested by Measurement Canada, but is also of the view that an independent meter test should only be undertaken when other possible explanations of higher-than-expected consumption have been investigated and ruled-out. For example, the data captured by smart meters provide an opportunity for customers to gain significant insight into consumption within their homes. Online tools are available to view this data and in-home displays can also be used to see consumption circuit-by-circuit in real time.

While investigating complaints, BC Hydro reviews the customer's account to confirm that a billing issue is not the cause of the high consumption. Also, failing any other explanation, BC Hydro has on occasion utilized its data scientists to perform more detailed analysis.

BC Hydro's experience is that at some stage during the investigation the cause of the perceived high-bill is discovered to be unrelated to the accuracy of the meter.

Customer requests for meter tests are not common, with only 157 in F2015. However, if the charge is reduced to $30, BC Hydro is concerned that additional customers would request an independent meter test rather than first taking the steps to investigate their own consumption as described above.

129.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.6, pp. 8-16 and 8-17
Proposed Meter Test charge

On page 8-17 of its Application, BC Hydro identifies 3 options for the Meter Test charge:

- Option 1 – the updated default Minimum Reconnection Charge 1 of $30;
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With respect to the options for the proposed Meter Test charge, BC Hydro submits on page 8-17 of its Application that "COPE 378 expressed concern that both option 2 and option 3 may result in some customers with legitimate concerns foregoing their right to have the meter tested out of concern they would be charged if the meter passes."

BC Hydro further submits on page 8-17 of the Application that it "agrees with BCOAPO and FNEMC that option 2 is preferable because it provides full cost recovery."

1.129.2 How often are meters tested as part of Measurement Canada regulations, other legislation or regulation, or internal BC Hydro policy? What is the normal rotation of meters for testing?

RESPONSE:

BC Hydro's new meter population will be sample tested in accordance with Measurement Canada's policies and specifications. Most meters will undergo sampling after ten years, followed by subsequent sampling programs at eight years, then six years, then four years, and finally two years, assuming the sampling proves the meters remain accurate.

BC Hydro will likely sample some groups earlier than the initial ten-year interval to spread the sampling effort over a few years. This will also provide an indication of the populations' performance in advance of the initial ten-year seal expiry, which will mitigate the risk of overdue meters if samples were to fail.

129.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.6, pp. 8-16 and 8-17
Proposed Meter Test charge

On page 8-17 of its Application, BC Hydro identifies 3 options for the Meter Test charge:

- Option 1 – the updated default Minimum Reconnection Charge 1 of $30;
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With respect to the options for the proposed Meter Test charge, BC Hydro submits on page 8-17 of its Application that "COPE 378 expressed concern that both option 2 and option 3 may result in some customers with legitimate concerns foregoing their right to have the meter tested out of concern they would be charged if the meter passes."

BC Hydro further submits on page 8-17 of the Application that it "agrees with BCOAPO and FNEMC that option 2 is preferable because it provides full cost recovery."

1.129.3 In the event that Option 1 or Option 3 become the Meter Test Charge, please identify the revenue shortfall that would be required to be absorbed by BC Hydro's other ratepayers and the rate impact.

RESPONSE:

If assuming there are 150 customer-requested meter tests each year:

Revenue from Option 1: 150 x $30 = $4,500

Revenue from Option 2: 150 x $181 = $27,150

Revenue from Option 3: 150 x $125 = $18,750

Therefore, the revenue shortfalls from Option 1 and 3 are:

Option 1: $27,150 - $4,500 = $22,650

Option 3: $27,150 - $18,750 = $8,400

Both Option 1 and 3 result in a revenue short-fall; however, the impact to general rates is insignificant.

129.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.6, pp. 8-16 and 8-17
Proposed Meter Test charge

On page 8-17 of its Application, BC Hydro identifies 3 options for the Meter Test charge:

- Option 1 – the updated default Minimum Reconnection Charge 1 of $30;
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With respect to the options for the proposed Meter Test charge, BC Hydro submits on page 8-17 of its Application that "COPE 378 expressed concern that both option 2 and option 3 may result in some customers with legitimate concerns foregoing their right to have the meter tested out of concern they would be charged if the meter passes."

BC Hydro further submits on page 8-17 of the Application that it "agrees with BCOAPO and FNEMC that option 2 is preferable because it provides full cost recovery."

1.129.4 Please provide the total cost incurred by BC Hydro for F2015 related to sending customers' meters to Measurement Canada for testing. Please show all calculations.

RESPONSE:

In addition to the $181 field metering costs, administrative and courier costs incurred for each Measurement Canada meter test request are as follows:

- **Administrative cost: $44.30 (one hour processing time of a Field Service Administrator); and**
- **Courier: $50 per meter.**

BC Hydro estimates the total F2015 costs for sending customers' meters to Measurement Canada for testing is ($181 + $44.30 + $50) X 157 = $43,222.

130.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, p. 6
Proposed Meter Test Charge – vehicle costs

The calculation for the proposed Meter Test Charge of $181 is included in Appendix G-1B, page 6. It includes vehicle costs determined as 29 percent of the labour required.

1.130.1 Please explain the rationale for using a percentage of labour required to determine the vehicle costs, as opposed to vehicle hourly rate.

RESPONSE:

The vehicle used by a crew varies from location to location, depending on availability at that location (it may be anything from a pick-up truck to a bucket truck, which have very different hourly rates). The calculations for the 29 per cent is based on the total annual fleet costs for all Distribution line vehicles (including depreciation, fuel, maintenance and insurance) over the total productive field worker hours which comes out to an average hourly rate of $24/hour which is 29 per cent of the hourly standard labour rate of $82.99.

130.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, p. 6
Proposed Meter Test Charge – vehicle costs

The calculation for the proposed Meter Test Charge of $181 is included in Appendix G-1B, page 6. It includes vehicle costs determined as 29 percent of the labour required.

1.130.2 Please provide supporting calculations for the unloaded labour cost and crew cost.

RESPONSE:

The unloaded SLR is provided as follows:

SLR Calculation	$/Hour
Base Pay	42.35
Benefits	16.70
Concessions	23.94
Total SLR	82.99

The total crew labour cost is calculated as follows:

Crew	1 PLT
Time Requirement	0.25 hours site time + 0.6 hours travel time = 0.85 hours
Total Labour Cost	0.85 hours x $82.99 (unloaded SLR) = $70.54

130.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, p. 6
Proposed Meter Test Charge – vehicle costs

The calculation for the proposed Meter Test Charge of $181 is included in Appendix G-1B, page 6. It includes vehicle costs determined as 29 percent of the labour required.

1.130.3 With respect to the costs incurred for the meter test, please provide the following:

- vehicle type used;
- hourly rate for vehicle type used; and
- calculation of vehicle cost input to the Meter Test Charge using the hourly rate for the vehicle type used.

RESPONSE:

The vehicle used for meter tests would most likely be a walk-in van.

The current hourly rate for a walk-in van is $21.34 per hour.

Based on the expected time requirement of 0.85 hour, the vehicle cost portion of the Meter Test Charge = 0.85 x $21.34 = $18.14.

131.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, p. 6
Proposed Meter Test Charge – total labour

The Meter Test Charge "Basis for Calculation" schedule found in Appendix G-1B of the BC Hydro Application includes a loaded SLR of $143.57.

1.131.1 Is a powerline technician required for the removal of the meter in order to facilitate a meter test? Please discuss why or why not.

RESPONSE:

Two resource types are able to exchange the meter to facilitate a meter test: PLT or Meter Technician. The choice of the resource is generally based on availability and proximity to the premises.

131.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, p. 6
Proposed Meter Test Charge – total labour

The Meter Test Charge "Basis for Calculation" schedule found in Appendix G-1B of the BC Hydro Application includes a loaded SLR of $143.57.

1.131.1 Is a powerline technician required for the removal of the meter in order to facilitate a meter test? Please discuss why or why not.

1.131.1.1 If the answer to the aforementioned IR is no, please provide the appropriate employee type required and the related loaded SLR.

RESPONSE:

The SLR for a Meter Technician is $116.60 per hour, including vehicle costs.

132.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, p. 6
Proposed Meter Test Charge – other charges

1.132.1 Does BC Hydro incur any additional costs in order to have a meter tested by Measurement Canada, other than those outlined in Appendix G-1B, page 6? Specifically, charges from Measurement Canada, customer service costs or other costs subsequent to the meter test? If yes, please provide the weighted average cost per meter for each type of additional cost, with a demonstration of the cost calculation.

RESPONSE:

Measurement Canada does not charge BC Hydro for meter tests.

Additional costs incurred by BC Hydro include:

- **Call Centre cost: $18.15;**
  - **Average of 20-minute handle time of the initial complaint handled by call centre agent and work leader;**
- **Meter Shop Administration cost: $46.84;**
  - **Average of 60 minutes of processing time; and**
- **Courier cost: $50.**

Therefore, BC Hydro incurs $115 of additional costs per meter test that will not be recovered through the proposed Meter Test Charge.

132.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Appendix G-1B, p. 6
Proposed Meter Test Charge – other charges

1.132.2 What is the revenue requirement impact of excluding these costs from the proposed Meter Test Charge and the resulting rate impact?

RESPONSE:

Assuming 150 meter tests per year, the additional $115 cost per meter test results in an under-recovery of $17,250 per year. This cost is insignificant in BC Hydro's overall revenue requirement and would not have a rate impact.

133.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.1, pp. 8-17 and 8-18
Collection charge

BC Hydro states on page 8-17 of the Application that the Collection Charge is no longer relevant because:

(i) RDR capability from smart meters means most disconnections are performed without the need to dispatch a crew; and
(ii) Crews are no longer permitted to accept payments for safety and security reasons.

1.133.1 For F2015, what percentage of disconnections required a crew to be dispatched?

RESPONSE:

Between May 2014 and April 2015, crews manually performed 1,772 of the 33,757 disconnections for non-payment, or 5.3 per cent.

133.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.1, pp. 8-17 and 8-18
Collection charge

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(i) RDR capability from smart meters means most disconnections are performed without the need to dispatch a crew; and
(ii) Crews are no longer permitted to accept payments for safety and security reasons.

1.133.2 Did BC Hydro encounter any situations in F2015 where crews were dispatched to perform a disconnection but did not follow through with the disconnection due to a customer indicating his/her intent to make payment?

RESPONSE:

Unless there are extenuating circumstances such as unsafe conditions or concern for the customer's health and welfare, disconnection orders are only to be cancelled by the credit team.

In some instances a FMA will agree to postpone a disconnection for a few hours if a customer indicates he or she will make a payment immediately. This would only be done if the FMA is working in the area and returning to the premises does not require much additional travel.

When returning later that day, the FMA would not follow through with the disconnection if the customer provides proof of payment. The Collection Charge might then be applied. However, disconnection would proceed if proof was not provided, even if the customer still indicated his or her intent to make payment.

In F2015 there were only 16 situations in which the Collection Charge was applied, with total revenue of $624.

133.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.1, pp. 8-17 and 8-18
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(i) RDR capability from smart meters means most disconnections are performed without the need to dispatch a crew; and
(ii) Crews are no longer permitted to accept payments for safety and security reasons.

1.133.2 Did BC Hydro encounter any situations in F2015 where crews were dispatched to perform a disconnection but did not follow through with the disconnection due to a customer indicating his/her intent to make payment?

1.133.2.1 If yes, or if there are other scenarios where a disconnection was not completed by a dispatch crew, how does BC Hydro propose to recover these costs in lieu of the Collection Charge?

RESPONSE:

BC Hydro's intention of disconnecting an active account is to persuade the customer to pay for energy consumed. Disconnecting the customer's service also avoids further uncollectible revenue being expensed as bad debt if they do not pay. Therefore, even if the trip did not end in a disconnection, the primary objective is met if payment is obtained from the customer.

Given the limited number of occurrences and value to all customers in minimizing bad debts, the costs of dispatching the crew are proposed to be recovered through general rates.

133.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.1, pp. 8-17 and 8-18
Collection charge

BC Hydro states on page 8-17 of the Application that the Collection Charge is no longer relevant because:

(i) RDR capability from smart meters means most disconnections are performed without the need to dispatch a crew; and
(ii) Crews are no longer permitted to accept payments for safety and security reasons.

1.133.3 If the Collection Charge was not eliminated, what amount would BC Hydro propose for this charge? Please explain the rationale for this amount.

RESPONSE:

BC Hydro would propose to charge the proposed $30 Minimum Reconnection Charge.

The weighted average cost of dispatching a resource to perform a manual disconnection is approximately $181. However, given that the customer would be charged only $30 if the crew actually disconnected the service, it is not appropriate to charge the full cost.

134.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.2, p. 8-18
DataPlus Service

BC Hydro states on page 8-18 of the Application that the current DataPlus Service Charge is $360 per year per Collective Master Account.

1.134.1 How much revenue was collected from the DataPlus Service Charge for F2015?

RESPONSE:

In F2015, BC Hydro collected revenue of $12,150 from the DataPlus Service Charge.

134.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.2, p. 8-18
DataPlus Service

BC Hydro states on page 8-18 of the Application that the current DataPlus Service Charge is $360 per year per Collective Master Account.

1.134.2 What was the total cost and the per customer cost for BC Hydro to provide the DataPlus Service in F2015? Please provide all calculations and explain any assumptions.

RESPONSE:

BC Hydro does not specifically track the cost of providing the DataPlus Service. However, estimated costs are as follows:

Labour	**$38,133**	**(0.5 FTE of a billing clerk)**
Materials	**2,000**	**(CD-ROMs and delivery costs)**
Total	**$40,133**	
Divided by	**43**	**customers**
Unit Cost	**$933**	**per customer**

134.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.2, p. 8-18
DataPlus Service

BC Hydro states on page 8-18 of the Application:

…an IT project is currently underway to address gaps in data and usability for some of the largest commercial customers. The DataPlus Service would be discontinued once the project is complete (tentatively mid-2016) and existing customers have been transitioned to the new self-service tool.

1.134.3 Please describe the IT project referenced in the above preamble.

RESPONSE:

The "MyHydro Data Download and Electronic Data Exchange" project (MyHydro EDX) was initiated to address a number of gaps and opportunities in how customers can access detailed electricity billing and consumption data through BC Hydro's online customer portal. The project scope includes:

- **Providing a centralized data download area within MyHydro to allow customers to initiate data downloads and, as applicable, retrieve output files;**
- **Providing consistency and improved data quality through a standardized download alternative to the five billing and/or consumption data export sources currently in use (which include DataPlus);**
- **Supporting the download of billing and consumption data for multiple accounts at once either in real-time or as scheduled downloads;**
- **Providing a foundation for customers to authorize third party data access to multiple accounts at once; and**
- **Adding a data output format aligned with Green Button, which is an XML standard used to support conservation and energy management.**

For clarity, the MyHydro EDX project was not initiated for the purpose of discontinuing the DataPlus Service. However, in doing so it will be possible for DataPlus Service customers to access their data themselves, making DataPlus Service redundant and allowing it to be discontinued.

134.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.2, p. 8-18
DataPlus Service

BC Hydro states on page 8-18 of the Application:

…an IT project is currently underway to address gaps in data and usability for some of the largest commercial customers. The DataPlus Service would be discontinued once the project is complete (tentatively mid-2016) and existing customers have been transitioned to the new self-service tool.

1.134.4 What is the forecast total cost of this IT project?

RESPONSE:

The current forecast cost at completion is $2.7 million.

134.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.2, p. 8-18
DataPlus Service

134.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

BC Hydro states on page 8-18 of the Application:

…an IT project is currently underway to address gaps in data and usability for some of the largest commercial customers. The DataPlus Service would be discontinued once the project is complete (tentatively mid-2016) and existing customers have been transitioned to the new self-service tool.

1.134.4.1 How does BC Hydro propose to recover the cost of this IT project?

RESPONSE:

As the service will be available to all customers, the costs will be recovered through rates rather than a standard charge. Please refer to BC Hydro's response to BCUC IR 1.134.5.2.

134.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.2, p. 8-18
DataPlus Service

BC Hydro states on page 8-18 of the Application:

…an IT project is currently underway to address gaps in data and usability for some of the largest commercial customers. The DataPlus Service would be discontinued once the project is complete (tentatively mid-2016) and existing customers have been transitioned to the new self-service tool.

1.134.5 Does BC Hydro anticipate that there will be ongoing administrative or other costs related to this project once it is complete and the existing DataPlus Service customers are transitioned to the new self-service tools?

RESPONSE:

The shift to a self-service model means there will not be ongoing administrative costs to extract data and mail CD-ROMs to DataPlus Service customers.

As with any IT project, MyHydro EDX will require ongoing sustainment to keep technology current.

134.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.2, p. 8-18
DataPlus Service

BC Hydro states on page 8-18 of the Application:

…an IT project is currently underway to address gaps in data and usability for some of the largest commercial customers. The DataPlus Service would be discontinued once the project is complete (tentatively mid-2016) and existing customers have been transitioned to the new self-service tool.

1.134.5 Does BC Hydro anticipate that there will be ongoing administrative or other costs related to this project once it is complete and the existing DataPlus Service customers are transitioned to the new self-service tools?

1.134.5.1 If no, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.134.5.

134.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.2, p. 8-18
DataPlus Service

BC Hydro states on page 8-18 of the Application:

…an IT project is currently underway to address gaps in data and usability for some of the largest commercial customers. The DataPlus Service would be discontinued once the project is complete (tentatively mid-2016) and existing customers have been transitioned to the new self-service tool.

1.134.5 Does BC Hydro anticipate that there will be ongoing administrative or other costs related to this project once it is complete and the existing DataPlus Service customers are transitioned to the new self-service tools?

1.134.5.2 If yes, please discuss if these ongoing costs should be recovered from the DataPlus Service customers through a revised charge.

RESPONSE:

No, the costs should not be recovered from the current DataPlus Service customers through a revised charge.

As described in BC Hydro's response to BCUC IR 1.134.3, the MyHydro EDX project will improve billing and consumption downloading capabilities for all Residential and General Service customers. It would not be appropriate to charge only those customers that are currently participating in DataPlus Service.

Similarly, it would not be appropriate to recover costs from only those customers that use the new tools through either a subscription charge or usage charge:

- **It is a core expectation that customers have the ability to download their consumption and billing data;**
- **A charge would be seen as punitive to those who are using the data to investigate a perceived billing issue; and**
- **A charge would be seen as a barrier to those wanting to better understand their consumption to manage costs and conserve energy.**

In addition, the structure of the data download will make it easier for customers with consolidated accounts to pay through low-cost channels such as Electronic Funds Transfer rather than by cheque. This provides cost savings for all customers. Providing MyHydro EDX as a free service supports this objective.

134.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.2, p. 8-18
DataPlus Service

BC Hydro states on page 8-18 of the Application:

…an IT project is currently underway to address gaps in data and usability for some of the largest commercial customers. The DataPlus Service would be discontinued once the project is complete (tentatively mid-2016) and existing customers have been transitioned to the new self-service tool.

1.134.6 What is the likelihood that completion of the IT project could be delayed to the end of 2016 or later? Please discuss.

RESPONSE:

The project is currently in the testing phase and go-live is targeted for February 1, 2016. It is unlikely the project would be delayed until the end of 2016.

134.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.7.2, p. 8-18
DataPlus Service

BC Hydro states on page 8-18 of the Application:

…an IT project is currently underway to address gaps in data and usability for some of the largest commercial customers. The DataPlus Service would be discontinued once the project is complete (tentatively mid-2016) and existing customers have been transitioned to the new self-service tool.

1.134.7 What steps is BC Hydro taking to ensure that the new self-service tools will meet the needs of the DataPlus service customers? Please discuss.

RESPONSE:

A sample of customers was initially involved during the requirements gathering phase to ensure that business needs would be addressed. BC Hydro also discussed requirements with a third-party software/services company that provides energy management and billing solutions for several large BC Hydro customers.

Also, in October 2015 ten external organizations were invited to participate in usability testing. These organizations included current DataPlus Service customers. Their feedback was used to refine the design.

135.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.4, pp. 8-19 to 8-22
Security Deposit

1.135.1 Does BC Hydro anticipate that creating increased flexibility for the application of security deposits will result in increased administration costs? Please discuss.

RESPONSE:

Ongoing impacts to administration costs are expected to be minimal.

Interest paid on security deposits would increase, as apartments are not generally assessed security deposits under current business practices.

In both cases, BC Hydro expects cost increases would be offset by a reduction in bad debts.

135.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.4, pp. 8-19 to 8-22
Security Deposit

1.135.2 Has BC Hydro experienced an increase in bad debt write-offs since the 2007 RDA was filed? If yes, please provide the approximate percentage increase in bad debt write-offs.

RESPONSE:

In F2008, bad debt expense was $4.14 million (0.19 per cent of sales).

In F2015, bad debt expense was $8.75 million (0.27 per cent of sales).

This represents an increase of 42 per cent when expressed as a percent of sales.

Please also refer to Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1 (section 4.3 – BC Hydro's Collections Performance).

135.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.4, pp. 8-19 to 8-22
Security Deposit

1.135.3 What is BC Hydro's average annual bad debt write-off? Please compare this amount to the three largest bad debt write-offs experienced in F2015.

RESPONSE:

BC Hydro analyzed the make-up of its residential bad debts for calendar 2014.

In that time, BC Hydro incurred a bad debt expense of $7.7 million from 28,133 residential accounts, or an average of $275 per account.

The three largest residential bad debt write-offs were:

- **$61,031;**
- **$42,788; and**
- **$42,506.**

135.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.4, pp. 8-19 to 8-22
Security Deposit

BC Hydro states on page 8-21 of the Application that its proposal benefits itself and customers in part because "collection processes can be modified to enable a progressive increase in the security deposit applied in situations warranted by the level of risk posed by the customers."

1.135.4 Please provide a more detailed explanation of how BC Hydro would determine the appropriate security deposit amount for different customers under the proposed new wording.

RESPONSE:

There are two scenarios in which security deposits apply – new accounts and existing customers with poor credit histories. The proposed wording would be applied differently in each scenario.

New Customers:

If the customer does not provide a reference or pass a credit check:

- **If living in an apartment, a $50 security deposit will be assessed for either a failure or refusal of a credit check;**
- **If living in other housing types:**
  - **A security deposit of the greater of $50 and 1x the expected average monthly bill will be applied if the customer fails the credit check because of lack of credit history; and**
  - **A security deposit of 2x or 3x the average monthly bill will be assessed if the customer refuses a credit check or fails because of bad credit.**

Deteriorated Credit:

If the customer had their security deposit waived when applying for service or had a good record of payments in the year prior to missing a payment, then the first issuance of a security deposit would be for 1x the average monthly bill. Subsequent missed payments would cause the security deposit to be increased to the maximum of 2x/3x the average monthly bill based on billing frequency.

135.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.4, pp. 8-19 to 8-22
Security Deposit

BC Hydro states on page 8-21 of the Application that its proposal benefits itself and customers in part because "collection processes can be modified to enable a progressive increase in the security deposit applied in situations warranted by the level of risk posed by the customers."

1.135.5 Given the increased flexibility the proposed wording provides as to the amount of security deposit charged to different customers, please discuss if the changes could cause the following: (i) a decreased customer understanding of how and when a security deposit is calculated/required; and (ii) a perceived lack of fairness amongst customers.

RESPONSE:

The proposed changes will provide greater clarity, not less:

- **The proposed approach is to assess a security deposit for anyone that does not pass a credit check or provide a reference;**
- **This removes uncertainty as compared to the amount of the bill also becoming a factor in when a security deposit is applied (i.e., Why does the security deposit need to be at least $110 before it is assessed?); and**
- **For apartments, the assessment of a flat $50 security deposit will also provide greater clarity as opposed to calculating it based on average consumption of a prior resident.**

Perception of fairness is also expected to improve with new rules:

- **Recent analysis shows that the $110 threshold for applying a security deposit is unrelated to the level of risk:**
  - **Small accounts pose a lower financial consequence but the occurrence of defaults is higher; and**
  - **Current perception may be that it is not "fair" to waive security deposits merely because a customer lives in an apartment.**
- **There is a difference between "bad credit" and "lack of credit" when failing a credit check;**

- **A customer receives a bad credit rating on the basis of a proven track record of late payments/non-payments with financial institutions, lending agencies and other utilities; and**
- **Many young adults or new residents fail the credit check simply because they don't have an established credit history. In these cases, there isn't evidence that the customer poses a risk of non-payment.**

- **Long-time customers with good payment histories sometimes enter dunning processes because of situations like loss of a job or illness/death in the family:**
  - **These customers do not perceive it to be fair when they are immediately assessed a security deposit of 2x/3x their average monthly bill; and**
  - **A graduated security deposit would provide a balance between not securing their account at all and imposing a large security deposit that would exacerbate the customer's financial situation.**
- **In all cases, the maximum security deposit would be assessed if the customer continues to miss payments.**

135.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.4, pp. 8-19 to 8-22
Security Deposit

BC Hydro states on page 8-21 of the Application that its proposal benefits itself and customers in part because "collection processes can be modified to enable a progressive increase in the security deposit applied in situations warranted by the level of risk posed by the customers."

1.135.6 Please provide a more detailed explanation of how BC Hydro would calculate standardized security deposit amounts.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.135.4.

135.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.4, pp. 8-19 to 8-22
Security Deposit

BC Hydro states on page 8-21 of the Application that its proposal benefits itself and customers in part because "collection processes can be modified to enable a progressive increase in the security deposit applied in situations warranted by the level of risk posed by the customers."

1.135.6.1 Please also explain which types of customers BC Hydro views as being potential candidates for standardized security deposits and why.

RESPONSE:

Standardized security deposits are most appropriate for new customers that reside in apartments and townhomes because:

- **Consumption is generally lower than in a detached home, and so there is less revenue at risk of non-collection;**
- **An average apartment has a bill of $26 to $45. Even with a broad range assumed for usage, it is unlikely that a $50 security deposit would exceed the allowable maximum assessment of 2x/3x the average monthly bill; and**
- **Rental premises often have frequent turn-over of residents. This makes it difficult to identify 'typical' consumption for the specific premises, and so the customer's estimated consumption is based on usage of a prior resident.**

There is more variability in consumption between detached houses than apartments. As a result, it is difficult to identify a standardized amount that balances the need to obtain sufficient security to mitigate risk with not over-assessing the customer relative to the maximum 2x/3x the average monthly bill.

136.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6, pp. 8-22 to 8-35
Potential low income customer terms and conditions

BC Hydro states as part of its comments in Table 8-6 (page 8-24) of the Application: "An income-based waiver [of a security deposit] would require a process to verify income and will have administrative costs."

1.136.1 Has BC Hydro explored the possibility of the Ministry of Social Development and Social Innovations undertaking the income verification process?

RESPONSE:

No, given that to date the triggers for a verification process have not been finalized. Discussions to date with MSDSI have focussed on improving processes related to the approximately 6,000 low income customers that have their electricity bills paid directly by MSDSI. Please refer to section 4.2 of Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

MSDSI's client list is a potential method of verifying eligibility. However, BC Hydro notes the following:

- **MSDSI does not provide support to all customers with income below the LICO threshold. Only two-thirds of the eligible low income customers would be clients of MSDSI. Other steps would need to be taken to verify eligibility for the remainder;**

- **MSDSI client lists are not static – they constantly change as clients enter or leave their programs. Accordingly, IT systems for the two organizations must be integrated such that eligibility is kept up to date. This has upfront and ongoing costs; and**

- **Additional effort would be required by both organizations to link MSDSI's client lists with BC Hydro accounts. This is not done currently except for customers having their electricity bills paid directly by MSDSI.**

136.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6, pp. 8-22 to 8-35
Potential low income customer terms and conditions

BC Hydro states as part of its comments in Table 8-6 (page 8-24) of the Application: "An income-based waiver [of a security deposit] would require a process to verify income and will have administrative costs."

1.136.1 Has BC Hydro explored the possibility of the Ministry of Social Development and Social Innovations undertaking the income verification process?

1.136.1.1 If yes, would this eliminate the additional administrative costs to BC Hydro of providing an income-based waiver? If not, please explain why not.

On page 8-29 of the Application, BC Hydro describes the jurisdictional review it conducted of Canadian and US electric utilities.

RESPONSE:

Even if MSDSI were to undertake an income verification process, it would not eliminate all additional administrative costs to BC Hydro. Please refer to BC Hydro's response to BCUC IR 1.136.1.

136.0 G. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6, pp. 8-22 to 8-35
Potential low income customer terms and conditions

BC Hydro states as part of its comments in Table 8-6 (page 8-24) of the Application: "An income-based waiver [of a security deposit] would require a process to verify income and will have administrative costs."

1.136.2 Please explain why BC Hydro did not include gas utilities as part of its jurisdictional review.

RESPONSE:

In BC Hydro's view, it was not necessary to include gas utilities as part of its low income rates/low income bill credit/low income terms and conditions jurisdictional review contained at Appendix C-3D of Exhibit B-1, pages 38 to 51 of 67:

- **BC Hydro surveyed nine Canadian jurisdictions and 12 U.S. jurisdictions. BC Hydro considers the scope of this review to be comprehensive in terms of geographic diversity as well as market relevance (inclusion of utilities operating as vertically integrated monopolies and utilities operating in Western Interconnection); and**

- **The issue of which jurisdictions to survey was the subject of engagement through 2015 RDA Workshop 9a and with BCOAPO (refer to the 'Background' section of the "Low Income Rate/Low Income Terms and Conditions/Low Income Demand Side Management Jurisdictional Review", Appendix C-3D, pages 23 to 25 of 67).**

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Date: November 17, 2015

VIA E-MAIL

British Columbia Utilities Commission
6th Floor – 900 Howe Street
Vancouver, BC V6Z 2V3

Attention: Erica Hamilton, Commission Secretary

Dear Sirs/Mesdames:

Re: BC Hydro 2015 Rate Design Application (RDA)
Association of Major Power Customers (AMPC) Information Request No. 1 to BC Hydro

We are legal counsel to AMPC in this matter. Further to the Regulatory Timetable set out in Order G-166-15, enclosed please find AMPC's Information Request No. 1 to BC Hydro.

Please contact the writer if you have any questions.

Yours truly,

Bull, Housser & Tupper LLP

Matthew D. Keen

ASSOCIATION OF MAJOR POWER CUSTOMERS OF BC (AMPC)
INFORMATION REQUEST NO. 1
TO BC HYDRO

British Columbia Hydro and Power Authority (BC Hydro)
2015 Rate Design Application Module 1

TABLE OF CONTENTS

A. COST OF SERVICE GENERAL 2
B. HERITAGE HYDRO 3
C. IPP GENERATION 5
D. THERMAL GENERATION 6
E. IT COSTS 7
F. TRANSMISSION EXTENSIONS AND TS6 8
G. BONBRIGHT CRITERIA WEIGHTING AND LRMC 8
H. TRANSMISSION SERVICE RATE CLASS 9
I. CUSTOMER BASELINE LOADS 11

A. COST OF SERVICE GENERAL

1.0 References:

Exhibit B-1, Application, Section 3.5, p. 3-7.

Exhibit B-1, Application, Appendix C-2A, Final Report – 2013 Cost of Service Methodology Review, p. 4 of 439.

Exhibit B-1, Application, Appendix C-2B, October 7, 2014 Workshop No. 4, Cost of Service (COS) Methodology – BC Hydro Summary and Consideration of Participant Feedback, p. 110 of 205.

On p. 3-7, BC Hydro indicates that its consultants ”reviewed BC Hydro’s COS analyses, models, spreadsheets used in ratemaking processes, and also undertook discussions with relevant BC Hydro business units whose costs impact the COS study”. BC Hydro’s consultants also reviewed “COS methodologies used by nine electric utilities in ten jurisdictions”.

At p. 110 of Appendix C-2B, BC Hydro further notes that it “proposes methodology changes to certain directives from the 2007 RDA Decision relating to DSM functionalization, BC Hydro Heritage hydroelectric Generation classification, IPP contract classification, Distribution classification and allocation, and Customer Care classification” on the basis of “recommendations from BC Hydro’s COS consultants, Cuthbert Consulting Inc. and NewGen Strategies and Solutions, LLC”.

1.1 Please provide all studies and supporting documentation provided by the SAIC/Leidos/NewGen/Cuthbert Consultants pertaining to the demand and energy classification of generating and transmission assets (Heritage hydro, thermal and contracted IPPs) and IT and metering costs in preparation for the RDA and workshops on Fully Allocated Cost of Service Studies <u>that are not currently on the record.</u>

2.0 Reference: Exhibit B-1, Application, Appendix C-2C, Draft F2016 Cost of Service (COS) Model, Tables 1 and 2, pp. 4 and 6 of 79.

In Table 1, BC Hydro provides the F2016 COS results using both BC Hydro’s proposed methodology and the same methodology used in its F2013 COS study, which used the 2007 RDA decision as its base.

In Table 2, BC Hydro then provides the impact of methodological changes by various classifications to the Residential revenue-to-cost (R/C) ratio, but does not provide the impact of changes for other rate classes.

2.1 With respect to the R/C ratios provided in Table 1 and Table 2 of the Draft F2016 COS Model (pages 4 to 6 of 79 of Appendix C-2C) please itemize the impact of each method change between the F2013 method using the 2007 RDA Decision

(column B) and the proposed method (column A) on the 2016 R/C ratios for each rate class (i.e. provide equivalent information for each rate class to that provided for the Residential rate class in Table 2 of Appendix C-2C).

B. HERITAGE HYDRO

3.0 References:

Exhibit B-1, Application, Section 3.7.1, p. 3-24.

Exhibit B-1, Application, Appendix C-2A, Workshop 2 Strawman Proposal, p. 248 of 439.

Exhibit B-1, Application, Appendix C-2B, Workshop 4 Discussion Guide, Section 4, pp. 66-67 of 205.

At p. 3-24, BC Hydro indicates that in the application it "uses a system load factor approach to classify Generation, resulting in a 55 per cent energy/45 per cent demand split".

At. p. 66 of 205 of Appendix C-2B, BC Hydro indicates it "believes…a load factor approach, is most appropriate…compared to a capacity factor approach weighted by book value". BC Hydro provides four reasons: (1) "[h]ydroelectric capacity…is not used exclusively to meet peak loads in the winter season" but is "also used to optimize the hydroelectric system and earn trade income for all ratepayers; (2) "there is reduced variability with the load factor approach", whereas the "capacity factor calculation can be variable year over year because of the addition of hydroelectric generating capacity, and (3) "[l]oad factor reflects actual retail usage of resources while the capacity factor reflects what resources are available to be used", and that assigning "costs based on actual usage…is more appropriate", and (4) "the load factor approach has jurisdictional support".

At p. 67 of 205 of Appendix C-2B, BC Hydro provides Table 5, which shows the R/C ratio impact of its preferred load factor approach:

Table 5 Hydroelectric Classification R/C Ratio Analysis

Customer Class	Base F2013 R/C Ratio (%)	Option 1A Load factor (total load) (%)	Preferred Option 1B Load Factor (IPP supply removed) (%)	Option 3 Capacity Factor (weighted by book value) (%)
Residential	89.8	90.9	90.5	90.0
SGS	126.7	126.1	126.4	126.6
MGS	120.8	120.3	120.5	120.7
LGS	102.1	101.3	101.6	102.0
Irrigation	86.6	82.3	84.1	85.8
Street Lighting	115.7	117.7	116.8	116.0
Transmission	104.4	102.3	103.2	104.0

3.1 Please confirm that all generators subject to dispatch provide both capacity and energy on the system. If not confirmed, please fully explain your response.

3.2 Please confirm that recent generation additions at Revelstoke and Mica provide both additional energy and capacity for the system. If not confirmed, please fully explain your response.

3.3 Please confirm that there is no standard and commonly used allocation between capacity and energy delivered by generators. If not confirmed, please fully explain your response.

3.4 Please provide examples of any jurisdictions that BC Hydro or its consultants are familiar with that use the capacity factor approach to classify generation assets.

3.5 Please provide examples of any jurisdictions that BC Hydro or its consultants are aware of that use the value of capacity approach to classify generation assets.

3.6 Please provide examples of any jurisdictions that BC Hydro or its consultants are aware of that classify hydraulic generation assets as more than 40% energy-related.

3.7 Please confirm that, since 2007, BC Hydro has seen an increase in the proportion of non-dispatchable generation on its system. If possible, please quantify this effect. If not confirmed, please fully explain your response.

3.8 Please confirm that BC Hydro's system is transitioning from an energy constrained system to a capacity constrained system. If not confirmed, please fully explain your response.

3.9 Please confirm that BC Hydro uses multi-year averages for stability purposes when calculating metrics used for rate design and cost allocation decisions, and provide examples. If not confirmed, please fully explain your response.

3.10 Please confirm that "Option 3" in Table 5 at p. 67 of Appendix C-2B of Exhibit B-1 reflects "Sensitivity 1" on page 3-24 of Exhibit B-1. If not confirmed, please provide a revised version of Table 5 showing the same analysis for Sensitivity 1.

3.11 Please recalculate the 2016-2019 revenue to cost ratios found in Table 5, replacing the heritage hydro generation classification of 55% energy and 45% demand with the previous classification of 45% energy and 55% demand (adding Sensitivity 1 per the response to 3.10 above if required), but applying that classification to all of:

(i) heritage hydro and IPP generation; and

(ii) heritage hydro, IPP and thermal generation.

C. IPP GENERATION

4.0 References:

Exhibit B-1, Application, Section 3.7.3, p. 3-26, Independent Power Producers (IPP)

Exhibit B-1, Application, Appendix C2-A, Attachment 4, pp. 2-3

At p. 3-26, BC Hydro's indicated that its "preferred IPP classification option is the 'Value of Capacity' option which results in a 93 per cent energy and 7 per cent demand classification." The Value of Capacity approach allocates the relative portion of IPP costs to demand "based on the relative portion of capacity benefits from the IPP portfolio over the IPP costs, as preferred for F2016 COS study purposes."

At p. 2-3, BC Hydro indicates that "a Fixed/Variable Approach Classifying IPP purchases on the basis of the fixed and variable components of IPP EPAs will produce counter intuitive results".

4.1 Please provide examples of any jurisdictions that BC Hydro or its consultants are familiar with that use the following approaches to classify generation assets:

(i) fixed/variable;

(ii) modified fixed/variable;

(iii) value of capacity; and

(iv) value of energy.

4.2 Please confirm that IPP contracts relate to generation assets that are non-dispatchable. If not confirmed, please fully explain your response.

4.3 Please confirm that all delivered generation associated with IPP contacts is compensated regardless of system demand. If not confirmed, please fully explain your response.

4.4 Please confirm that energy delivered by IPPs under long-term contracts does not vary in response to the hourly, daily, weekly, monthly or annual level of customers' aggregate energy consumption.

4.5 Please confirm that once BC Hydro enters into an IPP contract, its costs under the contract are fixed, rather than variable. If not confirmed, please fully explain your response.

4.6 Please confirm that an increased proportion of intermittent and seasonally varying energy sources interconnected to the system and not subject to dispatch by the utility operator places a greater reliance on other sources that can be dispatched to provide capacity. If not confirmed, please fully explain your response.

4.7 Please confirm that the use of net-metering and feed-in tariffs that provide "virtual energy storage" similarly place a greater reliance on sources that can be dispatched to provide capacity. If not confirmed, please fully explain your response.

D. THERMAL GENERATION

5.0 Reference: Exhibit B-1, Application, Section 3.7.2, p. 3-25

At p. 3-25, BC Hydro indicates that there are "three BC Hydro-owned thermal generating stations: Fort Nelson Generating Station (FNG), Prince Rupert Generating Station (PRG) and Burrard Generating Station (Burrard)." BC Hydro proposes the following for classifying these stations:

- FNG – use a load factor approach specific to the Fort Nelson service territory to classify FNG's O&M and capital generation costs. This results in a 74 per cent energy and 26 per cent demand classification. Fuel costs are classified as 100 per cent energy;

- PRG – For simplicity, use the system load factor with no adjustment for IPP supply to classify PRG's O&M and capital generation costs. This results in a 60 per cent energy and 40 per cent demand classification. Fuel costs are classified as 100 per cent energy; and

- Burrard – classify Burrard O&M and capital costs as 100 per cent demand with associated fuel costs treated as 100 per cent energy.

5.1 Please provide examples of classifications used for base-load and peaking thermal generation in other jurisdictions.

5.2 Please explain in detail why thermal generation is not 100% demand related.

5.3 Please confirm that the Burrard, Prince Rupert, and Fort Nelson generation facilities function as transmission, peaking and base load assets, respectively. If not confirmed, please fully explain your response.

E. IT COSTS

6.0 Reference: Exhibit B-1, Application, Section 3.6.5.1, p. 3-17

At p. 3-17, BC Hydro estimated the functional split in IT costs shown in Table 3-2.

Table 3-2 IT Functionalization

$ million	Generation (G), Transmission T), Distribution (D), Corporate (Co), Customer (Cu), and General (Ge)					
	G (%)	T (%)	D (%)	Cu (%)	Co (%)	Ge (%)
Bottom up functionalization	5	5	10	4	4	71
Bottom up functionalization based on COS functions	18.8[132]	22.1	41.5	17.7		
Status Quo Functionalized by Corporate O&M	30.0	29.7	30.3	9.9		

BC Hydro indicated that its "[c]osts were functionalized according to the main beneficiary of the services – Generation, Transmission, Distribution, etc", and where possible, "costs were functionalized directly".

6.1 Please provide the last 10 years of total IT costs for BC Hydro.

6.2 Please provide a detailed breakdown of IT costs by each utility function listed in the cost of service study.

6.3 Please show how each IT cost listed in 6.2 has changed in the function to which it was allocated during the past 10 years.

6.4 Please provide the total of all IT costs related to the implementation, operation or upgrade of "smart meters".

6.5 Please provide any data analyses extracted from "smart meters" and any associated reports generated within BC Hydro or by contractors.

6.6 Please provide the initial business case for "smart meters".

F. TRANSMISSION EXTENSIONS AND TS6

7.0 Reference: Exhibit B-1, Application, Section 1.5.2, p. 1-21

At p. 1-21, BC Hydro indicates that it "confirmed with stakeholders that Transmission extension policy and Distribution extension policy would be the subject of a later module (referred to as Module 2)."

7.1 Please confirm that BC Hydro's view is that tariff supplement number six requires updating. If not confirmed, please fully explain your response.

7.2 Please confirm that tariff supplement number six will continue to govern any 2015 and 2016 transmission extension applications. If not confirmed, please fully explain your response.

G. BONBRIGHT CRITERIA WEIGHTING AND LRMC

8.0 References:

Exhibit B-1, Application, Section 2.3.2.2, p. 2-46 and p. 2-52

Exhibit B-1, Application, Section 2.4.1, p. 2-56

At p. 2-46, BC Hydro discusses the concept of long run marginal cost as follows:

LRMC can be defined as the change in the long-run total cost resulting from a change in the quantity of output produced. In short, LRMC represents the price of the most cost-effective way of satisfying incremental customer demand where existing resources are insufficient to meet that demand. The standard economic technique used to determine LRMC is to calculate the minimum present-day view of the cost of meeting a permanent increment (or decrement) of demand in which all capital and operating production inputs can be considered variable.

BC Hydro then describes at p. 2-52 that its "energy LRMC outlook is as follows: $85/MWh-$100/MWh from F2017 to about F2030."

Finally, at p. 2-56, BC Hydro lists the four categories of Bonbright criteria it applied in stakeholder engagement: (1) Economic efficiency; (2) Fairness; (3) Practicality; and (4) Stability.

8.1 Please confirm that the long run marginal cost for electricity (LRMC) reflects the long-term projected cost to satisfy incremental customer electricity demand. If not confirmed, please fully explain your response.

8.2 Please confirm that the LRMC is a projection that is a function of a number of external factors including legislation, technology, and market conditions. If not confirmed, please fully explain your response.

8.3 Please confirm that because LRMC is a function of a number of external factors, there is uncertainty in determining the projected LRMC. If not confirmed, please fully explain your response.

8.4 Please confirm that as a result of the uncertainty in determining LRMC, any determination of LRMC must be viewed as a range of potential LRMCs that reflect the uncertainty that goes into the LRMC determination. If not confirmed, please fully explain your response.

8.5 Please confirm that BC Hydro's energy LRMC outlook of $85-$100 per MWh for F2017 to F2030 (RDA, p. 2-52) reflects such a range. If not confirmed, please fully explain your response.

8.6 Please confirm that because of the external factors that influence LRMC, the LRMC may fall outside BC Hydro's projected $85-$100 range in F2017 to F2030. If not confirmed, please fully explain your response.

8.7 Please confirm that the short run marginal cost for electricity (SRMC) can be less than the long run marginal cost. If not confirmed, please fully explain your response.

8.8 Please confirm that the SRMC can be less than the average cost of electricity. If confirmed, please estimate the SRMC for 2015. If not confirmed, please fully explain your response.

H. TRANSMISSION SERVICE RATE CLASS

9.0 Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

9.1 Please confirm that each of the following are currently included in the Transmission Service rate class:

i. New Westminster;
ii. FortisBC;
iii. UBC;
iv. SFU; and
v. YVR.

If not confirmed, please fully explain your response.

9.2 Please confirm that each of the following are not industrial customers:

i. New Westminster;
ii. FortisBC;
iii. UBC;
iv. SFU; and
v. YVR .

If not confirmed, please fully explain your response.

9.3 Please confirm that each of the following are better characterized as "wholesalers" to either residential, SGS or MGS customers than characterized as industrial customers:

i. New Westminster; and
ii. FortisBC.

If not confirmed, please fully explain your response.

9.4 Please confirm BC Hydro has previously included a separate rate class for wholesale customers in cost of service studies. If not confirmed, please fully explain your response.

9.5 Please confirm BC Hydro has the necessary data to prepare a cost of service study with wholesale customers as a separate rate class from other transmission level customers. If not confirmed, please fully explain your response.

9.6 Please confirm that UBC, SFU and YVR are being retained in the transmission rate class because their coincidence and load factor profiles resemble industrial customers, as shown in Figure 7 on page 61 of the Workshop 5 Consideration Memo at Appendix C-5A. If not confirmed, please fully explain your response.

9.7 Please confirm that price elasticity for electricity reflects responsiveness of the quantity of electric demanded by a customer in response to changes in electricity price. If not confirmed, please fully explain your response.

9.8 Please confirm that a price elastic electricity customer will have a greater than a 1% decrease in quantity demanded for each 1% increase in price. If not confirmed, please fully explain your response.

9.9 Please confirm that a price inelastic customer will have less than a 1% decrease in quantity demanded for each 1% increase in price. If not confirmed, please fully explain your response.

9.10 Please confirm that industrial customers are typically price elastic. If not confirmed, please fully explain your response.

9.11 Please confirm that each of the following customer types are typically price inelastic.

i. residential customers;
ii. SGS customers; and
iii. MGS customers.

If not confirmed, please fully explain your response.

9.12 Please provide the number of industrial customers that have ceased normal service under the Transmission Service rate class due to shut downs or for any other reason in 2015, and the associated aggregate load those customers represented before ceasing normal service.

9.13 Is BC Hydro aware of any other utilities that include wholesale-type customers like New Westminster and FortisBC the same rate class as industrial customers. If so, please list all example BC Hydro is aware of, including the type of customer and the rate class they are included in.

9.14 Please confirm that most utilities serve wholesale customers such as municipalities on a different rate schedule than industrial customers. If not confirmed, please fully explain your response.

I. CUSTOMER BASELINE LOADS

10.0 References:

Exhibit B-1, Application, Appendix C-2C, Schedule 1.0, p. 11 of 79.

Exhibit B-1, Application, Appendix C-2C, Schedule 5.0, p. 22 of 79.

Exhibit B-1, Application, Appendix C-2C, Schedule 5.1, p. 23 of 79.

In Schedule 1.0, BC Hydro lists its planned costs that make up its revenue requirement.

In Schedule 5.0, BC Hydro provides its energy allocators for F10-F14, F16, and F13.

In Schedule 5.1, BC Hydro provides its demand allocators for F10-F14 and F13.

10.1 Please confirm if the “Energy @ Customer Meter” figures used in Schedule 5.0 of the Cost of Service Study reflect the full customer baseline load (CBL) energy of all transmission customers. If not, please provide the values that would be included in Schedule 5.0 if showing the full Energy @ the Customer Meter reflecting the full CBL energy for all transmission customers (i.e., assuming all CBL was being used) including a description of any necessary estimates or assumptions.

10.2 Please discuss if there would be any revisions necessary to the Demand Allocators (Schedule 5.1) if the Schedule 5.0 was adjusted to reflect the full CBL of transmission customers (i.e., to ensure consistency between CBL energy and peak

loads). If so, please provide a version of schedule 5.1 reflecting this assumption, including any estimates and assumptions necessary.

10.3 Please discuss how the Planned Costs provided in schedule 1.0 of Appendix C-2C would change if BC Hydro were required (a) to serve the full CBL energy of all Transmission customers, and (b) to credit back to the Transmission class all costs incurred by Hydro (via foregone revenue) to acquire all assumed unused CBL energy at the Tier 2 rate (classified and allocated consistent with the treatment for IPP power acquisition). Please provide a revised version of Schedule 1.0 reflecting this assumption and a description of any estimates or assumptions used in preparing the analysis.

1.0 Topic: COST OF SERVICE GENERAL

References: Exhibit B-1, Application, Section 3.5, p. 3-7.
Exhibit B-1, Application, Appendix C-2A, Final Report – 2013 Cost of Service Methodology Review, p. 4 of 439.
Exhibit B-1, Application, Appendix C-2B, October 7, 2014 Workshop No. 4, Cost of Service (COS) Methodology – BC Hydro Summary and Consideration of Participant Feedback, p. 110 of 205.

On p. 3-7, BC Hydro indicates that its consultants ”reviewed BC Hydro’s COS analyses, models, spreadsheets used in ratemaking processes, and also undertook discussions with relevant BC Hydro business units whose costs impact the COS study”. BC Hydro’s consultants also reviewed “COS methodologies used by nine electric utilities in ten jurisdictions”.

At p. 110 of Appendix C-2B, BC Hydro further notes that it “proposes methodology changes to certain directives from the 2007 RDA Decision relating to DSM functionalization, BC Hydro Heritage hydroelectric Generation classification, IPP contract classification, Distribution classification and allocation, and Customer Care classification” on the basis of “recommendations from BC Hydro’s COS consultants, Cuthbert Consulting Inc. and NewGen Strategies and Solutions, LLC”.

1.1.1 Please provide all studies and supporting documentation provided by the SAIC/Leidos/NewGen/Cuthbert Consultants pertaining to the demand and energy classification of generating and transmission assets (Heritage hydro, thermal and contracted IPPs) and IT and metering costs in preparation for the RDA and workshops on Fully Allocated Cost of Service Studies <u>that are not currently on the record</u>.

RESPONSE:

There are no additional COS Consultant-related studies that are not on the record.

2.0 Topic: COST OF SERVICE GENERAL

Reference: Exhibit B-1, Application, Appendix C-2C, Draft F2016 Cost of Service (COS) Model, Tables 1 and 2, pp. 4 and 6 of 79.

In Table 1, BC Hydro provides the F2016 COS results using both BC Hydro's proposed methodology and the same methodology used in its F2013 COS study, which used the 2007 RDA decision as its base.

In Table 2, BC Hydro then provides the impact of methodological changes by various classifications to the Residential revenue-to-cost (R/C) ratio, but does not provide the impact of changes for other rate classes.

1.2.1 With respect to the R/C ratios provided in Table 1 and Table 2 of the Draft F2016 COS Model (pages 4 to 6 of 79 of Appendix C-2C) please itemize the impact of each method change between the F2013 method using the 2007 RDA Decision (column B) and the proposed method (column A) on the 2016 R/C ratios for each rate class (i.e. provide equivalent information for each rate class to that provided for the Residential rate class in Table 2 of Appendix C-2C).

RESPONSE:

The impact to R/C ratios to all rate classes of the F2016 COS methodology changes described in Table 2 of the draft F2015 COS Model description, Appendix C-2C of Exhibit B-1, are provided in the table below. Please note that Appendix C-2C was circulated to stakeholders in February 2015 and the final F2016 COS study filed in September 2015 as part of Exhibit B-1 incorporated additional adjustments, which are reflected in the updated R/C ratio changes for the Residential class provided here.

	Functionalization		**Classification**		
	IPP Capital Leases (%)	**IT Costs (%)**	**Distribution (%)**	**Customer Care (%)**	**Heritage Hydro (%)**
Residential	**1.4**	**-0.6**	**1.5**	**-1.1**	**0.8**
SGS	**0.9**	**-0.5**	**-0.4**	**0.4**	**0.0**
MGS	**0.2**	**-0.1**	**-3.2**	**2.5**	**0.1**
LGS	**-0.6**	**0.3**	**-2.9**	**2.5**	**-0.5**
Irrigation	**1.1**	**-1.7**	**-3.5**	**5.1**	**-3.3**
Street Lighting	**2.4**	**-0.4**	**-1.4**	**-1.0**	**1.7**
Transmission	**-3.7**	**1.8**	**0.0**	**-0.2**	**-1.7**

3.0 Topic: HERITAGE HYDRO

References: Exhibit B-1, Application, Section 3.7.1, p. 3-24.
Exhibit B-1, Application, Appendix C-2A, Workshop 2 Strawman Proposal, p. 248 of 439.
Exhibit B-1, Application, Appendix C-2B, Workshop 4 Discussion Guide, Section 4, pp. 66-67 of 205.

At p. 3-24, BC Hydro indicates that in the application it "uses a system load factor approach to classify Generation, resulting in a 55 per cent energy/45 per cent demand split".

At. p. 66 of 205 of Appendix C-2B, BC Hydro indicates it "believes…a load factor approach, is most appropriate…compared to a capacity factor approach weighted by book value". BC Hydro provides four reasons: (1) "[h]ydroelectric capacity…is not used exclusively to meet peak loads in the winter season" but is "also used to optimize the hydroelectric system and earn trade income for all ratepayers; (2) "there is reduced variability with the load factor approach", whereas the "capacity factor calculation can be variable year over year because of the addition of hydroelectric generating capacity, and (3) "[l]oad factor reflects actual retail usage of resources while the capacity factor reflects what resources are available to be used", and that assigning "costs based on actual usage…is more appropriate", and (4) "the load factor approach has jurisdictional support".

At p. 67 of 205 of Appendix C-2B, BC Hydro provides Table 5, which shows the R/C ratio impact of its preferred load factor approach:

Table 5 Hydroelectric Classification R/C Ratio Analysis

Customer Class	Base F2013 R/C Ratio (%)	Option 1A Load factor (total load) (%)	Preferred Option 1B Load Factor (IPP supply removed) (%)	Option 3 Capacity Factor (weighted by book value) (%)
Residential	89.8	90.9	90.5	90.0
SGS	126.7	126.1	126.4	126.6
MGS	120.8	120.3	120.5	120.7
LGS	102.1	101.3	101.6	102.0
Irrigation	86.6	82.3	84.1	85.8
Street Lighting	115.7	117.7	116.8	116.0
Transmission	104.4	102.3	103.2	104.0

1.3.1 Please confirm that all generators subject to dispatch provide both capacity and energy on the system. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed.

3.0 Topic: HERITAGE HYDRO

References: Exhibit B-1, Application, Section 3.7.1, p. 3-24.
Exhibit B-1, Application, Appendix C-2A, Workshop 2 Strawman Proposal, p. 248 of 439.
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MGS	120.8	120.3	120.5	120.7
LGS	102.1	101.3	101.6	102.0
Irrigation	86.6	82.3	84.1	85.8
Street Lighting	115.7	117.7	116.8	116.0
Transmission	104.4	102.3	103.2	104.0

1.3.2 Please confirm that recent generation additions at Revelstoke and Mica provide both additional energy and capacity for the system. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed. However, Revelstoke Unit 5 and Mica Units 5 and 6 primarily contribute incremental capacity rather than energy for the system.

3.0 Topic: HERITAGE HYDRO

References: Exhibit B-1, Application, Section 3.7.1, p. 3-24.
Exhibit B-1, Application, Appendix C-2A, Workshop 2 Strawman Proposal, p. 248 of 439.
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Irrigation	86.6	82.3	84.1	85.8
Street Lighting	115.7	117.7	116.8	116.0
Transmission	104.4	102.3	103.2	104.0

1.3.3 Please confirm that there is no standard and commonly used allocation between capacity and energy delivered by generators. If not confirmed, please fully explain your response.

RESPONSE:

BC Hydro interprets this question to refer to the classification between capacity and energy delivered by generators.

Table C-1 of the COS Methodology Review (page 85 of 439, Appendix C-2A of Exhibit B-1) shows that the utilities surveyed by the COS Consultants use at least five different methodologies to classify generation costs in COS studies.

3.0 Topic: HERITAGE HYDRO

References: Exhibit B-1, Application, Section 3.7.1, p. 3-24.
Exhibit B-1, Application, Appendix C-2A, Workshop 2 Strawman Proposal, p. 248 of 439.
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Street Lighting	115.7	117.7	116.8	116.0
Transmission	104.4	102.3	103.2	104.0

1.3.4 Please provide examples of any jurisdictions that BC Hydro or its consultants are familiar with that use the capacity factor approach to classify generation assets.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.25.5.

3.0 Topic: HERITAGE HYDRO

References: Exhibit B-1, Application, Section 3.7.1, p. 3-24.
Exhibit B-1, Application, Appendix C-2A, Workshop 2 Strawman Proposal, p. 248 of 439.
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Transmission	104.4	102.3	103.2	104.0

1.3.5 Please provide examples of any jurisdictions that BC Hydro or its consultants are aware of that use the value of capacity approach to classify generation assets.

RESPONSE:

The value of capacity is inherently used in the generation classification approaches by the following utilities as discussed in the COS Methodology Review:

- **Portland General Electric Company separately calculates long-run marginal production capacity and energy costs for a test year, thus identifying the demand-related and energy-related portions of marginal generation costs;**

- **Avista Corporation–Idaho uses a peak credit method for classification generation costs. This approach acknowledges that baseload production facilities provide energy throughout the year as well as capacity during system peaks. The demand/energy ratio is determined by the relationship of the current replacement cost per kW generating capacity of the company's peaking units to the current replacement cost per kW generating capacity of the company's thermal or hydro plant;**

- **Puget Sound Energy uses the ratio of the cost per kW-year of generating capacity for a proxy peaking generating resource to the cost per kW-year of generating capacity for a proxy baseload generating resource (thermal peak credit). The share of production costs attributable to demand is equal to the ratio; and**

- **Newfoundland Power purchases the majority of its power from Newfoundland and Labrador Hydro. Newfoundland Power classifies purchased power based on Newfoundland and Labrador Hydro's classified cost to serve Newfoundland Power.**

3.0 Topic: HERITAGE HYDRO

References: Exhibit B-1, Application, Section 3.7.1, p. 3-24.
Exhibit B-1, Application, Appendix C-2A, Workshop 2 Strawman Proposal, p. 248 of 439.
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Street Lighting	115.7	117.7	116.8	116.0
Transmission	104.4	102.3	103.2	104.0

1.3.6 Please provide examples of any jurisdictions that BC Hydro or its consultants are aware of that classify hydraulic generation assets as more than 40% energy-related.

RESPONSE:

Please refer to Table C-1 in the COS Methodology Review (page 85 of 439, Appendix C-2A, Exhibit B-1). All the utilities shown classify more than 40 per cent of costs related to hydroelectric generation assets as energy-related.

3.0 Topic: HERITAGE HYDRO

References: Exhibit B-1, Application, Section 3.7.1, p. 3-24.
Exhibit B-1, Application, Appendix C-2A, Workshop 2 Strawman Proposal, p. 248 of 439.
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Street Lighting	115.7	117.7	116.8	116.0
Transmission	104.4	102.3	103.2	104.0

1.3.7 Please confirm that, since 2007, BC Hydro has seen an increase in the proportion of non-dispatchable generation on its system. If possible, please quantify this effect. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed. Refer to table below.

Fiscal Year	Fraction of Load (Including Coordination Obligations) Served by Non-Dispatchable IPPs (%)
2007	**8**
2008	**9**
2009	**10**
2010	**12**
2011	**16**
2012	**17**
2013	**17**
2014	**17**
2015	**22**

Note that coordination obligations include energy schedules associated with the Canal Plant and Keenleyside Entitlement Agreements. The exclusion of such coordination obligations would increase the fraction of load by non-dispatchable IPPs.

3.0 Topic: HERITAGE HYDRO

References: Exhibit B-1, Application, Section 3.7.1, p. 3-24.
Exhibit B-1, Application, Appendix C-2A, Workshop 2 Strawman Proposal, p. 248 of 439.
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Residential	89.8	90.9	90.5	90.0
SGS	126.7	126.1	126.4	126.6
MGS	120.8	120.3	120.5	120.7
LGS	102.1	101.3	101.6	102.0
Irrigation	86.6	82.3	84.1	85.8
Street Lighting	115.7	117.7	116.8	116.0
Transmission	104.4	102.3	103.2	104.0

1.3.8 Please confirm that BC Hydro's system is transitioning from an energy constrained system to a capacity constrained system. If not confirmed, please fully explain your response.

RESPONSE:

As set out in the 2013 IRP, BC Hydro anticipates that in the future it will need to acquire additional capacity resources over and above the resources that it acquires for both energy and capacity benefits.

3.0 Topic: HERITAGE HYDRO

References: Exhibit B-1, Application, Section 3.7.1, p. 3-24.
Exhibit B-1, Application, Appendix C-2A, Workshop 2 Strawman Proposal, p. 248 of 439.
Exhibit B-1, Application, Appendix C-2B, Workshop 4 Discussion Guide, Section 4, pp. 66-67 of 205.

At p. 3-24, BC Hydro indicates that in the application it "uses a system load factor approach to classify Generation, resulting in a 55 per cent energy/45 per cent demand split".

At. p. 66 of 205 of Appendix C-2B, BC Hydro indicates it "believes…a load factor approach, is most appropriate…compared to a capacity factor approach weighted by book value". BC Hydro provides four reasons: (1) "[h]ydroelectric capacity…is not used exclusively to meet peak loads in the winter season" but is "also used to optimize the hydroelectric system and earn trade income for all ratepayers; (2) "there is reduced variability with the load factor approach", whereas the "capacity factor calculation can be variable year over year because of the addition of hydroelectric generating capacity, and (3) "[l]oad factor reflects actual retail usage of resources while the capacity factor reflects what resources are available to be used", and that assigning "costs based on actual usage…is more appropriate", and (4) "the load factor approach has jurisdictional support".

At p. 67 of 205 of Appendix C-2B, BC Hydro provides Table 5, which shows the R/C ratio impact of its preferred load factor approach:

Table 5 Hydroelectric Classification R/C Ratio Analysis

Customer Class	Base F2013 R/C Ratio (%)	Option 1A Load factor (total load) (%)	Preferred Option 1B Load Factor (IPP supply removed) (%)	Option 3 Capacity Factor (weighted by book value) (%)
Residential	89.8	90.9	90.5	90.0
SGS	126.7	126.1	126.4	126.6
MGS	120.8	120.3	120.5	120.7
LGS	102.1	101.3	101.6	102.0
Irrigation	86.6	82.3	84.1	85.8
Street Lighting	115.7	117.7	116.8	116.0
Transmission	104.4	102.3	103.2	104.0

1.3.9 Please confirm that BC Hydro uses multi-year averages for stability purposes when calculating metrics used for rate design and cost allocation decisions, and provide examples. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed. Five-year average of rate class contributions to 4CP and NCP loads are used to assign demand-related costs to rate classes in the F2016 COS study.

3.0 Topic: HERITAGE HYDRO

References: Exhibit B-1, Application, Section 3.7.1, p. 3-24.
Exhibit B-1, Application, Appendix C-2A, Workshop 2 Strawman Proposal, p. 248 of 439.
Exhibit B-1, Application, Appendix C-2B, Workshop 4 Discussion Guide, Section 4, pp. 66-67 of 205.

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At p. 67 of 205 of Appendix C-2B, BC Hydro provides Table 5, which shows the R/C ratio impact of its preferred load factor approach:

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Residential	89.8	90.9	90.5	90.0
SGS	126.7	126.1	126.4	126.6
MGS	120.8	120.3	120.5	120.7
LGS	102.1	101.3	101.6	102.0
Irrigation	86.6	82.3	84.1	85.8
Street Lighting	115.7	117.7	116.8	116.0
Transmission	104.4	102.3	103.2	104.0

1.3.10 Please confirm that "Option 3" in Table 5 at p. 67 of Appendix C-2B of Exhibit B-1 reflects "Sensitivity 1" on page 3-24 of Exhibit B-1. If not confirmed, please provide a revised version of Table 5 showing the same analysis for Sensitivity 1.

RESPONSE:

Confirmed. Capacity factor is the method of classification used in both Option 3 in Table 5 of the Workshop 4 Discussion Guide (Appendix C-2B) and Sensitivity Number 1 on page 3-24 of Exhibit B-1.

3.0 Topic: HERITAGE HYDRO

References: Exhibit B-1, Application, Section 3.7.1, p. 3-24.
Exhibit B-1, Application, Appendix C-2A, Workshop 2 Strawman Proposal, p. 248 of 439.
Exhibit B-1, Application, Appendix C-2B, Workshop 4 Discussion Guide, Section 4, pp. 66-67 of 205.

At p. 3-24, BC Hydro indicates that in the application it "uses a system load factor approach to classify Generation, resulting in a 55 per cent energy/45 per cent demand split".

At. p. 66 of 205 of Appendix C-2B, BC Hydro indicates it "believes…a load factor approach, is most appropriate…compared to a capacity factor approach weighted by book value". BC Hydro provides four reasons: (1) "[h]ydroelectric capacity…is not used exclusively to meet peak loads in the winter season" but is "also used to optimize the hydroelectric system and earn trade income for all ratepayers; (2) "there is reduced variability with the load factor approach", whereas the "capacity factor calculation can be variable year over year because of the addition of hydroelectric generating capacity, and (3) "[l]oad factor reflects actual retail usage of resources while the capacity factor reflects what resources are available to be used", and that assigning "costs based on actual usage…is more appropriate", and (4) "the load factor approach has jurisdictional support".

At p. 67 of 205 of Appendix C-2B, BC Hydro provides Table 5, which shows the R/C ratio impact of its preferred load factor approach:

Table 5 Hydroelectric Classification R/C Ratio Analysis

Customer Class	Base F2013 R/C Ratio (%)	Option 1A Load factor (total load) (%)	Preferred Option 1B Load Factor (IPP supply removed) (%)	Option 3 Capacity Factor (weighted by book value) (%)
Residential	89.8	90.9	90.5	90.0
SGS	126.7	126.1	126.4	126.6
MGS	120.8	120.3	120.5	120.7
LGS	102.1	101.3	101.6	102.0
Irrigation	86.6	82.3	84.1	85.8
Street Lighting	115.7	117.7	116.8	116.0
Transmission	104.4	102.3	103.2	104.0

1.3.11 Please recalculate the 2016-2019 revenue to cost ratios found in Table 5, replacing the heritage hydro generation classification of 55% energy and 45% demand with the previous classification of 45% energy and 55% demand (adding Sensitivity 1 per the response to 3.10 above if required), but applying that classification to all of:

(i) heritage hydro and IPP generation; and

(ii) heritage hydro, IPP and thermal generation.

RESPONSE:

The requested classification methodology has been applied to the forecast R/C ratios using the 2007 RDA Decision methodology except as described. For option (i), heritage hydro and IPP costs have been classified as 55 per cent demand and 45 per cent energy with thermal costs classified as 45 per cent demand and 55 per cent energy. For option (ii), heritage hydro, IPP costs and thermal costs have been classified as 55 per cent demand and 45 per cent energy.

Customer Class	Base Forecast F2016 R/C Ratio using 2007 RDA Methodology (%)	AMPC IR 1.3.11 Option (i) (%)	AMPC IR 1.3.11 Option (ii) (%)
Residential	**91.7**	**89.4**	**89.4**
SGS	**118.3**	**118.2**	**118.2**
MGS	**120.9**	**120.7**	**120.7**
LGS	**99.4**	**100.9**	**100.9**
Irrigation	**92.9**	**105.0**	**105.1**
Street Lighting	**126.5**	**121.6**	**121.6**
Transmission	**105.4**	**111.0**	**111.0**

Note: The "Base Forecast" reflects the four changes listed on page 3-11 of Exhibit B-1, lines 11 to 18.

4.0 Topic: IPP GENERATION

References: Exhibit B-1, Application, Section 3.7.3, p. 3-26, Independent Power Producers (IPP)
Exhibit B-1, Application, Appendix C2-A, Attachment 4, pp. 2-3

At p. 3-26, BC Hydro's indicated that its "preferred IPP classification option is the 'Value of Capacity' option which results in a 93 per cent energy and 7 per cent demand classification." The Value of Capacity approach allocates the relative portion of IPP costs to demand "based on the relative portion of capacity benefits from the IPP portfolio over the IPP costs, as preferred for F2016 COS study purposes."

At p. 2-3, BC Hydro indicates that "a Fixed/Variable Approach Classifying IPP purchases on the basis of the fixed and variable components of IPP EPAs will produce counter intuitive results".

1.4.1 Please provide examples of any jurisdictions that BC Hydro or its consultants are familiar with that use the following approaches to classify generation assets:

(i) fixed/variable;

(ii) modified fixed/variable;

(iii) value of capacity; and

(iv) value of energy.

RESPONSE:

Responses by the type of classification approach are as follows:

Fixed/Variable and Modified Fixed/Variable

- **The meanings of these terms are not clear. BC Hydro considered an approach of classifying the costs of IPP purchases based on the fixed and variable components of IPP EPAs (refer to Attachment 4 of the Workshop 2 consideration memo, pages 430 to 432 of 439, Appendix C-2A, Exhibit B-1). However, this approach is not transferable to the cost classification of generation assets owned by utilities because there are no corresponding fixed and variable contract costs associated with these assets. In general, the majority of COS methodologies involve classification of generation asset costs into fixed and variable components. For example, a commonly used reference for generation asset cost allocation between fixed and variable costs is the National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual (1992).**

Value of Capacity/Energy

- **Please refer to BC Hydro's response to AMPC IR 1.3.5.**

4.0 Topic: IPP GENERATION

References: Exhibit B-1, Application, Section 3.7.3, p. 3-26, Independent Power Producers (IPP)
Exhibit B-1, Application, Appendix C2-A, Attachment 4, pp. 2-3

At p. 3-26, BC Hydro's indicated that its "preferred IPP classification option is the 'Value of Capacity' option which results in a 93 per cent energy and 7 per cent demand classification." The Value of Capacity approach allocates the relative portion of IPP costs to demand "based on the relative portion of capacity benefits from the IPP portfolio over the IPP costs, as preferred for F2016 COS study purposes."

At p. 2-3, BC Hydro indicates that "a Fixed/Variable Approach Classifying IPP purchases on the basis of the fixed and variable components of IPP EPAs will produce counter intuitive results".

1.4.2 Please confirm that IPP contracts relate to generation assets that are non-dispatchable. If not confirmed, please fully explain your response.

RESPONSE:

The majority of IPP contracts are take-or-pay and do not have provisions allowing BC Hydro to dispatch or curtail IPP generation.

BC Hydro has some IPP contracts that provide dispatch such as Island Generation, Arrow Lakes, Brilliant Expansion and Waneta Expansion. Further, BC Hydro has negotiated separate turn-down agreements with select biomass plants that allow BC Hydro to reduce the output of the project for various reasons such as low market prices, system constraints and freshet oversupply. Also, the Standing Offer Program specimen EPA includes a "Dispatch/Turn-Down" provision that permits BC Hydro to turn down or shut off a facility when the IPP is not subject to operational, technical or regulatory constraints.

4.0 Topic: IPP GENERATION

References: Exhibit B-1, Application, Section 3.7.3, p. 3-26, Independent Power Producers (IPP)
Exhibit B-1, Application, Appendix C2-A, Attachment 4, pp. 2-3

At p. 3-26, BC Hydro's indicated that its "preferred IPP classification option is the 'Value of Capacity' option which results in a 93 per cent energy and 7 per cent demand classification." The Value of Capacity approach allocates the relative portion of IPP costs to demand "based on the relative portion of capacity benefits from the IPP portfolio over the IPP costs, as preferred for F2016 COS study purposes."

At p. 2-3, BC Hydro indicates that "a Fixed/Variable ApproachClassifying IPP purchases on the basis of the fixed and variable components of IPP EPAs will produce counter intuitive results".

1.4.3 Please confirm that all delivered generation associated with IPP contacts is compensated regardless of system demand. If not confirmed, please fully explain your response.

RESPONSE:

All delivered electricity associated with IPP EPAs is paid for in accordance with contract terms. There are no EPAs for which payment terms explicitly reflect actual system demand at the time of generation; however, the pricing structure of many EPAs includes time-of-delivery price adjustment factors that increase or decrease the contractual base price depending upon the time of day and the month of the year when energy is delivered. The price adjusters and associated time-of-delivery periods are aligned with BC Hydro's typical system demand to the extent that factors that increase the price typically occur in periods of higher demand, while factors that decrease the price typically occur in periods of lower demand. This structure may influence how an IPP determines its bid price and operates its generation resources which, in turn, will determine its compensation.

4.0 Topic: IPP GENERATION

References: Exhibit B-1, Application, Section 3.7.3, p. 3-26, Independent Power Producers (IPP)
Exhibit B-1, Application, Appendix C2-A, Attachment 4, pp. 2-3

At p. 3-26, BC Hydro's indicated that its "preferred IPP classification option is the 'Value of Capacity' option which results in a 93 per cent energy and 7 per cent demand classification." The Value of Capacity approach allocates the relative portion of IPP costs to demand "based on the relative portion of capacity benefits from the IPP portfolio over the IPP costs, as preferred for F2016 COS study purposes."

At p. 2-3, BC Hydro indicates that "a Fixed/Variable Approach Classifying IPP purchases on the basis of the fixed and variable components of IPP EPAs will produce counter intuitive results".

1.4.4 Please confirm that energy delivered by IPPs under long-term contracts does not vary in response to the hourly, daily, weekly, monthly or annual level of customers' aggregate energy consumption.

RESPONSE:

If an EPA has turn-down or dispatch provisions, BC Hydro may request a reduction or modification to the output of the IPP project for various reasons such as changes in system need. Please refer to BC Hydro's response to AMPC IR 1.4.2.

If an EPA has time-of-delivery payment provisions, an IPP may change the timing of its energy deliveries to align with higher valued payment periods. Please refer to BC Hydro's response to AMPC IR 1.4.3.

4.0 Topic: IPP GENERATION

References: Exhibit B-1, Application, Section 3.7.3, p. 3-26, Independent Power Producers (IPP)
Exhibit B-1, Application, Appendix C2-A, Attachment 4, pp. 2-3

At p. 3-26, BC Hydro's indicated that its "preferred IPP classification option is the 'Value of Capacity' option which results in a 93 per cent energy and 7 per cent demand classification." The Value of Capacity approach allocates the relative portion of IPP costs to demand "based on the relative portion of capacity benefits from the IPP portfolio over the IPP costs, as preferred for F2016 COS study purposes."

At p. 2-3, BC Hydro indicates that "a Fixed/Variable Approach Classifying IPP purchases on the basis of the fixed and variable components of IPP EPAs will produce counter intuitive results".

1.4.5 Please confirm that once BC Hydro enters into an IPP contract, its costs under the contract are fixed, rather than variable. If not confirmed, please fully explain your response.

RESPONSE:

Generally EPA terms are fixed but the associated electricity costs are not. Costs will vary in accordance with changes to variables such as delivery volumes, price escalation factors and time-of-delivery adjustments.

4.0 Topic: IPP GENERATION

References: Exhibit B-1, Application, Section 3.7.3, p. 3-26, Independent Power Producers (IPP)
Exhibit B-1, Application, Appendix C2-A, Attachment 4, pp. 2-3

At p. 3-26, BC Hydro's indicated that its "preferred IPP classification option is the 'Value of Capacity' option which results in a 93 per cent energy and 7 per cent demand classification." The Value of Capacity approach allocates the relative portion of IPP costs to demand "based on the relative portion of capacity benefits from the IPP portfolio over the IPP costs, as preferred for F2016 COS study purposes."

At p. 2-3, BC Hydro indicates that "a Fixed/Variable Approach Classifying IPP purchases on the basis of the fixed and variable components of IPP EPAs will produce counter intuitive results".

1.4.6 Please confirm that an increased proportion of intermittent and seasonally varying energy sources interconnected to the system and not subject to dispatch by the utility operator places a greater reliance on other sources that can be dispatched to provide capacity. If not confirmed, please fully explain your response.

RESPONSE:

Interconnecting non-dispatchable intermittent resources requires other dispatchable capacity resources to manage their energy fluctuations and continue to meet load requirements. A greater proportion of non-dispatchable intermittent resources would require a greater amount of dispatchable capacity resources. Note that these intermittent resources can be generating electricity to serve peak load. BC Hydro counts on these resources probabilistic contribution through the Effective Load Carrying Capability using a loss of load expectation criteria of no greater than one day in ten years to meet its system capacity requirement.

4.0 Topic: IPP GENERATION

References: Exhibit B-1, Application, Section 3.7.3, p. 3-26, Independent Power Producers (IPP)
Exhibit B-1, Application, Appendix C2-A, Attachment 4, pp. 2-3

At p. 3-26, BC Hydro's indicated that its "preferred IPP classification option is the 'Value of Capacity' option which results in a 93 per cent energy and 7 per cent demand classification." The Value of Capacity approach allocates the relative portion of IPP costs to demand "based on the relative portion of capacity benefits from the IPP portfolio over the IPP costs, as preferred for F2016 COS study purposes."

At p. 2-3, BC Hydro indicates that "a Fixed/Variable Approach Classifying IPP purchases on the basis of the fixed and variable components of IPP EPAs will produce counter intuitive results".

1.4.7 Please confirm that the use of net-metering and feed-in tariffs that provide "virtual energy storage" similarly place a greater reliance on sources that can be dispatched to provide capacity. If not confirmed, please fully explain your response.

RESPONSE:

BC Hydro does not understand what is meant by the phrase "virtual energy storage". Resources that are the subject of BC Hydro's Net Metering Rate (RS 1289) are not dispatchable. Currently BC Hydro has no feed-in tariff program.

5.0 Topic: THERMAL GENERATION

Reference: Exhibit B-1, Application, Section 3.7.2, p. 3-25

At p. 3-25, BC Hydro indicates that there are "three BC Hydro-owned thermal generating stations: Fort Nelson Generating Station (FNG), Prince Rupert Generating Station (PRG) and Burrard Generating Station (Burrard)." BC Hydro proposes the following for classifying these stations:

- FNG – use a load factor approach specific to the Fort Nelson service territory to classify FNG's O&M and capital generation costs. This results in a 74 per cent energy and 26 per cent demand classification. Fuel costs are classified as 100 per cent energy;
- PRG – For simplicity, use the system load factor with no adjustment for IPP supply to classify PRG's O&M and capital generation costs. This results in a 60 per cent energy and 40 per cent demand classification. Fuel costs are classified as 100 per cent energy; and
- Burrard – classify Burrard O&M and capital costs as 100 per cent demand with associated fuel costs treated as 100 per cent energy.

1.5.1 Please provide examples of classifications used for base-load and peaking thermal generation in other jurisdictions.

RESPONSE:

Please refer to Tables C-2 and C-3 in the COS Methodology Review (Appendix C-2A of Exhibit B-1, pages 87 to 90 of 439).

5.0 Topic: THERMAL GENERATION

Reference: Exhibit B-1, Application, Section 3.7.2, p. 3-25

At p. 3-25, BC Hydro indicates that there are "three BC Hydro-owned thermal generating stations: Fort Nelson Generating Station (FNG), Prince Rupert Generating Station (PRG) and Burrard Generating Station (Burrard)." BC Hydro proposes the following for classifying these stations:

- FNG – use a load factor approach specific to the Fort Nelson service territory to classify FNG's O&M and capital generation costs. This results in a 74 per cent energy and 26 per cent demand classification. Fuel costs are classified as 100 per cent energy;
- PRG – For simplicity, use the system load factor with no adjustment for IPP supply to classify PRG's O&M and capital generation costs. This results in a 60 per cent energy and 40 per cent demand classification. Fuel costs are classified as 100 per cent energy; and
- Burrard – classify Burrard O&M and capital costs as 100 per cent demand with associated fuel costs treated as 100 per cent energy.

1.5.2 Please explain in detail why thermal generation is not 100% demand related.

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 1.5.3.

5.0 Topic: THERMAL GENERATION

Reference: Exhibit B-1, Application, Section 3.7.2, p. 3-25

At p. 3-25, BC Hydro indicates that there are "three BC Hydro-owned thermal generating stations: Fort Nelson Generating Station (FNG), Prince Rupert Generating Station (PRG) and Burrard Generating Station (Burrard)." BC Hydro proposes the following for classifying these stations:

- FNG – use a load factor approach specific to the Fort Nelson service territory to classify FNG's O&M and capital generation costs. This results in a 74 per cent energy and 26 per cent demand classification. Fuel costs are classified as 100 per cent energy;
- PRG – For simplicity, use the system load factor with no adjustment for IPP supply to classify PRG's O&M and capital generation costs. This results in a 60 per cent energy and 40 per cent demand classification. Fuel costs are classified as 100 per cent energy; and
- Burrard – classify Burrard O&M and capital costs as 100 per cent demand with associated fuel costs treated as 100 per cent energy.

1.5.3 Please confirm that the Burrard, Prince Rupert, and Fort Nelson generation facilities function as transmission, peaking and base load assets, respectively. If not confirmed, please fully explain your response.

RESPONSE:

BC Hydro describes the role of each plant in section 5 of the Workshop 4 Discussion Guide (pages 68 to 70 of 205, Appendix C-2B, Exhibit B-1).

Burrard

- **The primary purpose of Burrard is to provide voltage support for the transmission system. The F2016 COS study functionalizes Burrard's costs as generation and classifies the fuel portion as 100 per cent energy and the non-fuel portion (O&M and capital costs) as 100 per cent demand-related. Since fuel costs are directly proportional to energy consumption, they are appropriately classified as energy;**

- **Note that the functionalization of Burrard's non-fuel costs between generation and transmission does not impact the final classification and allocation of its non-fuel costs because costs functionalized to transmission in the F2016 COS study are also classified as 100 per cent demand-related and use the same allocator (4CP) as generation demand-related costs.**

Prince Rupert Generating Station

- **PRG's primary function is to provide reliability backup for the transmission system serving Prince Rupert. Historically, its operation is dependent on the timing of transmission outages which can occur in peak or non-peak times. Since these costs occur throughout the year they are more appropriately classified as both energy and demand-related rather than 100 per cent demand-related.**

Fort Nelson

- **BC Hydro agrees with the characterization of FNG as a base load asset, which are commonly classified as both energy and demand-related rather than 100 per cent demand-related in COS studies.**

6.0 Topic: IT COSTS

Reference: Exhibit B-1, Application, Section 3.6.5.1, p. 3-17

At p. 3-17, BC Hydro estimated the functional split in IT costs shown in Table 3-2.

Table 3-2 IT Functionalization

$ million	Generation (G), Transmission T), Distribution (D), Corporate (Co), Customer (Cu), and General (Ge)					
	G (%)	T (%)	D (%)	Cu (%)	Co (%)	Ge (%)
Bottom up functionalization	5	5	10	4	4	71
Bottom up functionalization based on COS functions	18.8[132]	22.1	41.5	17.7		
Status Quo Functionalized by Corporate O&M	30.0	29.7	30.3	9.9		

BC Hydro indicated that its "[c]osts were functionalized according to the main beneficiary of the services – Generation, Transmission, Distribution, etc", and where possible, "costs were functionalized directly".

1.6.1 Please provide the last 10 years of total IT costs for BC Hydro.

RESPONSE:

Due to various reorganizations over the past ten years, including the merger of BCTC and BC Hydro, it would take considerable effort to provide a ten-year history of OM&A related IT costs that could be meaningfully compared on a year over year basis.

To be responsive to this IR, BC Hydro provides a five-year history for the Technology group.

	Actuals ($ million)				**Plan ($ million)**
	F2012	**F2013**	**F2014**	**F2015**	**F2016**
Technology Costs	**100.5**	**101.7**	**109.3**	**111.1**	**109.3**

Note 1 F2016 Plan excludes Revenue Assurance and Field Investigations (transferred to Customer Services with a budget of $2.2 million.

Note 2 F2013/F2014 Actuals are consistent with F15/F16 RRA Schedule 5.2 (excluding Integrated Security which transferred to Properties).

6.0 Topic: IT COSTS

Reference: Exhibit B-1, Application, Section 3.6.5.1, p. 3-17

At p. 3-17, BC Hydro estimated the functional split in IT costs shown in Table 3-2.

Table 3-2 IT Functionalization

$ million	Generation (G), Transmission T), Distribution (D), Corporate (Co), Customer (Cu), and General (Ge)					
	G (%)	T (%)	D (%)	Cu (%)	Co (%)	Ge (%)
Bottom up functionalization	5	5	10	4	4	71
Bottom up functionalization based on COS functions	18.8[132]	22.1	41.5	17.7		
Status Quo Functionalized by Corporate O&M	30.0	29.7	30.3	9.9		

BC Hydro indicated that its "[c]osts were functionalized according to the main beneficiary of the services – Generation, Transmission, Distribution, etc", and where possible, "costs were functionalized directly".

1.6.2 Please provide a detailed breakdown of IT costs by each utility function listed in the cost of service study.

RESPONSE:

A detailed breakdown by function is not available. BC Hydro rejected a bottom up functionalization approach in section 3.6.5.1 of Exhibit B-1.

BC Hydro notes that Schedule 3.1 of the F2015-F2016 RRA, lines 57 to 61 allocates total corporate costs to the Generation, Transmission, Distribution and Customer Care functions using a using a top down approach that's based on each function's share of overall cost.

If these allocators were used to apportion IT costs, rather than Corporate OMA (which was used in the F2016 COS model as shown in Table 3-2 of Exhibit B-1), IT costs would be functionalized as follows:

	F2016 Plan	
F2015-F2016 RRA Schedule 3.1 Allocators for Balance of Corporate Group Costs	**(%)**	**($ million)**
Generation	**27.9**	**30.5**
Transmission	**31.8**	**34.8**
Distribution	**31.6**	**34.5**
Customer Care	**8.8**	**9.6**

6.0 Topic: IT COSTS

Reference: Exhibit B-1, Application, Section 3.6.5.1, p. 3-17

At p. 3-17, BC Hydro estimated the functional split in IT costs shown in Table 3-2.

Table 3-2 IT Functionalization

$ million	Generation (G), Transmission T), Distribution (D), Corporate (Co), Customer (Cu), and General (Ge)					
	G (%)	T (%)	D (%)	Cu (%)	Co (%)	Ge (%)
Bottom up functionalization	5	5	10	4	4	71
Bottom up functionalization based on COS functions	18.8[132]	22.1	41.5	17.7		
Status Quo Functionalized by Corporate O&M	30.0	29.7	30.3	9.9		

BC Hydro indicated that its "[c]osts were functionalized according to the main beneficiary of the services – Generation, Transmission, Distribution, etc", and where possible, "costs were functionalized directly".

1.6.3 Please show how each IT cost listed in 6.2 has changed in the function to which it was allocated during the past 10 years.

RESPONSE:

As stated in BC Hydro's response to AMPC IR 1.6.1, a ten-year history of IT costs is not available. However, in recent years IT costs have been functionalized as 100 per cent Generation until the proposed F2016 update to the methodology described in section 3.6.5.1 of Exhibit B-1.

6.0 Topic: IT COSTS

Reference: Exhibit B-1, Application, Section 3.6.5.1, p. 3-17

At p. 3-17, BC Hydro estimated the functional split in IT costs shown in Table 3-2.

Table 3-2 IT Functionalization

$ million	Generation (G), Transmission T), Distribution (D), Corporate (Co), Customer (Cu), and General (Ge)					
	G (%)	T (%)	D (%)	Cu (%)	Co (%)	Ge (%)
Bottom up functionalization	5	5	10	4	4	71
Bottom up functionalization based on COS functions	18.8[132]	22.1	41.5	17.7		
Status Quo Functionalized by Corporate O&M	30.0	29.7	30.3	9.9		

BC Hydro indicated that its "[c]osts were functionalized according to the main beneficiary of the services – Generation, Transmission, Distribution, etc", and where possible, "costs were functionalized directly".

1.6.4 Please provide the total of all IT costs related to the implementation, operation or upgrade of "smart meters".

RESPONSE:

SMI IT Sustainment Costs	**F2016 Plan ($ million)**
Revenue Assurance and Field Investigations	**6.7**
Technology	**26.0**
Total	**32.7**

Note 1 **The above IT SMI Sustainment Costs are deferred in F2016 and are shown as an addition to the SMI deferral account in the F2016 Plan. Therefore, these costs can be considered Customer-related for the purposes of the F2016 COS study.**

Note 2 **Revenue Assurance and Field Investigations transferred from Technology to Customer Services in F2016.**

Note 3 **Implementation costs of approximately $176 million were captured in the SMI capital project.**

6.0 Topic: IT COSTS

Reference: Exhibit B-1, Application, Section 3.6.5.1, p. 3-17

At p. 3-17, BC Hydro estimated the functional split in IT costs shown in Table 3-2.

Table 3-2 IT Functionalization

$ million	Generation (G), Transmission T), Distribution (D), Corporate (Co), Customer (Cu), and General (Ge)					
	G (%)	T (%)	D (%)	Cu (%)	Co (%)	Ge (%)
Bottom up functionalization	5	5	10	4	4	71
Bottom up functionalization based on COS functions	18.8[132]	22.1	41.5	17.7		
Status Quo Functionalized by Corporate O&M	30.0	29.7	30.3	9.9		

BC Hydro indicated that its "[c]osts were functionalized according to the main beneficiary of the services – Generation, Transmission, Distribution, etc", and where possible, "costs were functionalized directly".

1.6.5 Please provide any data analyses extracted from "smart meters" and any associated reports generated within BC Hydro or by contractors.

RESPONSE:

BC Hydro notes that AMPC IRs 1.6.5 and 1.6.6 are un-related to IT functionalization.

BC Hydro discussed this AMPC IR with AMPC counsel, and conveyed that in BC Hydro's view, the requested information is broad in scope temporally and in terms of subject matter, as it conceivably is a request for actual load profiles.

BC Hydro submits there are only two SMI-related issues relevant to the 2015 RDA:

1. **F2016 COS - How to classify deferred SMI costs[1] between energy, demand and customer-related (section 3.7.8 of Exhibit B-1) and how SMI enabled BC Hydro to better understand the load characteristics of its distribution voltage customers and to better allocate costs within the F2016 COS study (Exhibit B-1, section 2.3.2.1).**

   With regard to COS SMI regulatory account cost classification, some 2015 RDA stakeholders such as COPE 378 maintain that the Smart Metering and Infrastructure Program Business Case, filed with the Commission on January 18, 2011 (with a copy provided to the interveners registered for the F09/F10 RRA and to those registered for the F11 RRA), is relevant. After discussion with AMPC counsel, BC Hydro understands that

[1] Less than one third of total SMI costs were subject to regulatory account treatment, as per Commission Order No. G-115-11. The SMI regulatory account is being amortized over 15 years, which began in F2015. The annual amortization of the SMI regulatory account is the subject amount of the SMI classification discussion in the F2015 COS study.

AMPC is not requesting that a copy of the SMI business case be put on the RDA record.

BC Hydro has SMI enabled load profile data, and has extracted and used such SMI data to create the F2013 and F2014 load research profiles and to directly assign BC Hydro owned transformers to rate classes as part of the transformer analysis (refer to Workshop 4 presentation, page 45 to 52 of 205, Appendix C-2B, Exhibit B-1).

2. **Rate Design – Has BC Hydro studied rate designs that SMI may enable, such as voluntary TOU rates for Residential and/or General Service customers? This is discussed in BC Hydro's response to COPE 378 IRs 1.4.1 to 1.4.4, 1.5.1, 1.5.2 and 1.6.3.**

6.0 Topic: IT COSTS

Reference: Exhibit B-1, Application, Section 3.6.5.1, p. 3-17

At p. 3-17, BC Hydro estimated the functional split in IT costs shown in Table 3-2.

Table 3-2 IT Functionalization

$ million	**Generation (G), Transmission T), Distribution (D), Corporate (Co), Customer (Cu), and General (Ge)**					
	G (%)	**T (%)**	**D (%)**	**Cu (%)**	**Co (%)**	**Ge (%)**
Bottom up functionalization	5	5	10	4	4	71
Bottom up functionalization based on COS functions	18.8[132]	22.1	41.5	17.7		
Status Quo Functionalized by Corporate O&M	30.0	29.7	30.3	9.9		

BC Hydro indicated that its "[c]osts were functionalized according to the main beneficiary of the services – Generation, Transmission, Distribution, etc", and where possible, "costs were functionalized directly".

1.6.6 Please provide the initial business case for "smart meters".

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 1.6.5.

7.0 Topic: TRANSMISSION EXTENSIONS AND TS6

Reference: Exhibit B-1, Application, Section 1.5.2, p. 1-21

At p. 1-21, BC Hydro indicates that it "confirmed with stakeholders that Transmission extension policy and Distribution extension policy would be the subject of a later module (referred to as Module 2)."

1.7.1 Please confirm that BC Hydro's view is that tariff supplement number six requires updating. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed. BC Hydro will be engaging with stakeholders in 2016 regarding changes to TS 6 as part of RDA Module 2.

7.0 Topic: TRANSMISSION EXTENSIONS AND TS6

Reference: Exhibit B-1, Application, Section 1.5.2, p. 1-21

At p. 1-21, BC Hydro indicates that it "confirmed with stakeholders that Transmission extension policy and Distribution extension policy would be the subject of a later module (referred to as Module 2)."

1.7.2 Please confirm that tariff supplement number six will continue to govern any 2015 and 2016 transmission extension applications. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed.

8.0 Topic: BONBRIGHT CRITERIA WEIGHTING AND LRMC

References: Exhibit B-1, Application, Section 2.3.2.2, p. 2-46 and p. 2-52
Exhibit B-1, Application, Section 2.4.1, p. 2-56

At p. 2-46, BC Hydro discusses the concept of long run marginal cost as follows:

LRMC can be defined as the change in the long-run total cost resulting from a change in the quantity of output produced. In short, LRMC represents the price of the most cost-effective way of satisfying incremental customer demand where existing resources are insufficient to meet that demand. The standard economic technique used to determine LRMC is to calculate the minimum present-day view of the cost of meeting a permanent increment (or decrement) of demand in which all capital and operating production inputs can be considered variable.

BC Hydro then describes at p. 2-52 that its "energy LRMC outlook is as follows: $85/MWh-$100/MWh from F2017 to about F2030."

Finally, at p. 2-56, BC Hydro lists the four categories of Bonbright criteria it applied in stakeholder engagement: (1) Economic efficiency; (2) Fairness; (3) Practicality; and (4) Stability.

1.8.1 Please confirm that the long run marginal cost for electricity (LRMC) reflects the long-term projected cost to satisfy incremental customer electricity demand. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed.

8.0 Topic: BONBRIGHT CRITERIA WEIGHTING AND LRMC

References: Exhibit B-1, Application, Section 2.3.2.2, p. 2-46 and p. 2-52
Exhibit B-1, Application, Section 2.4.1, p. 2-56

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BC Hydro then describes at p. 2-52 that its "energy LRMC outlook is as follows: $85/MWh-$100/MWh from F2017 to about F2030."

Finally, at p. 2-56, BC Hydro lists the four categories of Bonbright criteria it applied in stakeholder engagement: (1) Economic efficiency; (2) Fairness; (3) Practicality; and (4) Stability.

1.8.2 Please confirm that the LRMC is a projection that is a function of a number of external factors including legislation, technology, and market conditions. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed.

8.0 Topic: BONBRIGHT CRITERIA WEIGHTING AND LRMC

References: Exhibit B-1, Application, Section 2.3.2.2, p. 2-46 and p. 2-52
Exhibit B-1, Application, Section 2.4.1, p. 2-56

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BC Hydro then describes at p. 2-52 that its "energy LRMC outlook is as follows: $85/MWh-$100/MWh from F2017 to about F2030."

Finally, at p. 2-56, BC Hydro lists the four categories of Bonbright criteria it applied in stakeholder engagement: (1) Economic efficiency; (2) Fairness; (3) Practicality; and (4) Stability.

1.8.3 Please confirm that because LRMC is a function of a number of external factors, there is uncertainty in determining the projected LRMC. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed.

8.0 Topic: BONBRIGHT CRITERIA WEIGHTING AND LRMC

References: Exhibit B-1, Application, Section 2.3.2.2, p. 2-46 and p. 2-52
Exhibit B-1, Application, Section 2.4.1, p. 2-56

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BC Hydro then describes at p. 2-52 that its "energy LRMC outlook is as follows: $85/MWh-$100/MWh from F2017 to about F2030."

Finally, at p. 2-56, BC Hydro lists the four categories of Bonbright criteria it applied in stakeholder engagement: (1) Economic efficiency; (2) Fairness; (3) Practicality; and (4) Stability.

1.8.4 Please confirm that as a result of the uncertainty in determining LRMC, any determination of LRMC must be viewed as a range of potential LRMCs that reflect the uncertainty that goes into the LRMC determination. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed. Please refer to BC Hydro's response to BCUC IR 1.60.5 for more discussion on the LRMC range.

8.0 Topic: BONBRIGHT CRITERIA WEIGHTING AND LRMC

References: Exhibit B-1, Application, Section 2.3.2.2, p. 2-46 and p. 2-52
Exhibit B-1, Application, Section 2.4.1, p. 2-56

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BC Hydro then describes at p. 2-52 that its "energy LRMC outlook is as follows: $85/MWh-$100/MWh from F2017 to about F2030."

Finally, at p. 2-56, BC Hydro lists the four categories of Bonbright criteria it applied in stakeholder engagement: (1) Economic efficiency; (2) Fairness; (3) Practicality; and (4) Stability.

1.8.5 Please confirm that BC Hydro's energy LRMC outlook of $85-$100 per MWh for F2017 to F2030 (RDA, p. 2-52) reflects such a range. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed. Please refer to BC Hydro's response to BCUC IR 1.60.5 for more discussion on the LRMC range.

8.0 Topic: BONBRIGHT CRITERIA WEIGHTING AND LRMC

References: Exhibit B-1, Application, Section 2.3.2.2, p. 2-46 and p. 2-52
Exhibit B-1, Application, Section 2.4.1, p. 2-56

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BC Hydro then describes at p. 2-52 that its "energy LRMC outlook is as follows: $85/MWh-$100/MWh from F2017 to about F2030."

Finally, at p. 2-56, BC Hydro lists the four categories of Bonbright criteria it applied in stakeholder engagement: (1) Economic efficiency; (2) Fairness; (3) Practicality; and (4) Stability.

1.8.6 Please confirm that because of the external factors that influence LRMC, the LRMC may fall outside BC Hydro's projected $85-$100 range in F2017 to F2030. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed. Please refer to BC Hydro's response to BCUC IR 1.60.5 for more discussion on the LRMC range.

8.0 Topic: BONBRIGHT CRITERIA WEIGHTING AND LRMC

References: Exhibit B-1, Application, Section 2.3.2.2, p. 2-46 and p. 2-52
Exhibit B-1, Application, Section 2.4.1, p. 2-56

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BC Hydro then describes at p. 2-52 that its "energy LRMC outlook is as follows: $85/MWh-$100/MWh from F2017 to about F2030."

Finally, at p. 2-56, BC Hydro lists the four categories of Bonbright criteria it applied in stakeholder engagement: (1) Economic efficiency; (2) Fairness; (3) Practicality; and (4) Stability.

1.8.7 Please confirm that the short run marginal cost for electricity (SRMC) can be less than the long run marginal cost. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed.

8.0 Topic: BONBRIGHT CRITERIA WEIGHTING AND LRMC

References: Exhibit B-1, Application, Section 2.3.2.2, p. 2-46 and p. 2-52
Exhibit B-1, Application, Section 2.4.1, p. 2-56

At p. 2-46, BC Hydro discusses the concept of long run marginal cost as follows:

LRMC can be defined as the change in the long-run total cost resulting from a change in the quantity of output produced. In short, LRMC represents the price of the most cost-effective way of satisfying incremental customer demand where existing resources are insufficient to meet that demand. The standard economic technique used to determine LRMC is to calculate the minimum present-day view of the cost of meeting a permanent increment (or decrement) of demand in which all capital and operating production inputs can be considered variable.

BC Hydro then describes at p. 2-52 that its "energy LRMC outlook is as follows: $85/MWh-$100/MWh from F2017 to about F2030."

Finally, at p. 2-56, BC Hydro lists the four categories of Bonbright criteria it applied in stakeholder engagement: (1) Economic efficiency; (2) Fairness; (3) Practicality; and (4) Stability.

1.8.8 Please confirm that the SRMC can be less than the average cost of electricity. If confirmed, please estimate the SRMC for 2015. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed. BC Hydro's Short Run Marginal Cost of new supply is based on wholesale electricity market (referred to as spot market) prices at the Mid C trading hub. These market prices can be less than BC Hydro's average, embedded cost of electricity at $44/MWh, which is calculated using functionalized Generation costs from the F2016 COS study. The market price for year 2015 up to October 31, 2015 averages at $24.10/MWh (USD) and $30.50/MWh (CDN) using the Bank of Canada historical daily noon exchange rate.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

1.9.1 Please confirm that each of the following are currently included in the Transmission Service rate class:

i. New Westminster;
ii. FortisBC;
iii. UBC;
iv. SFU; and
v. YVR.

If not confirmed, please fully explain your response.

RESPONSE:

Confirmed.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

1.9.2 Please confirm that each of the following are not industrial customers:

i. New Westminster;
ii. FortisBC;
iii. UBC;
iv. SFU; and
v. YVR .

If not confirmed, please fully explain your response.

RESPONSE:

Confirmed. The customers listed in the IR are not part of the industrial sector as defined by the North American Industry Classification System.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

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1.9.3 Please confirm that each of the following are better characterized as "wholesalers" to either residential, SGS or MGS customers than characterized as industrial customers:

i. New Westminster; and
ii. FortisBC.

If not confirmed, please fully explain your response.

RESPONSE:

Confirmed. However, BC Hydro notes that FortisBC and New Westminster also serve larger commercial and industrial customers.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

1.9.4 Please confirm BC Hydro has previously included a separate rate class for wholesale customers in cost of service studies. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed. Please refer to section 3.2 of the Workshop 10 consideration memo (Exhibit B-1, Appendix C-5B), page 96 of 212.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

1.9.5 Please confirm BC Hydro has the necessary data to prepare a cost of service study with wholesale customers as a separate rate class from other transmission level customers. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

1.9.6 Please confirm that UBC, SFU and YVR are being retained in the transmission rate class because their coincidence and load factor profiles resemble industrial customers, as shown in Figure 7 on page 61 of the Workshop 5 Consideration Memo at Appendix C-5A. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

1.9.7 Please confirm that price elasticity for electricity reflects responsiveness of the quantity of electric demanded by a customer in response to changes in electricity price. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed. Elasticity is typically used to define the price response of a group of customers or a market, rather than a single customer.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

1.9.8 Please confirm that a price elastic electricity customer will have a greater than a 1% decrease in quantity demanded for each 1% increase in price. If not confirmed, please fully explain your response.

RESPONSE:

As set out in BC Hydro's response to AMPC IR 1.9.10, a price elasticity of demand that is between -1 and zero is defined as inelastic.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

1.9.9 Please confirm that a price inelastic customer will have less than a 1% decrease in quantity demanded for each 1% increase in price. If not confirmed, please fully explain your response.

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 1.9.8.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

1.9.10 Please confirm that industrial customers are typically price elastic. If not confirmed, please fully explain your response.

RESPONSE:

BC Hydro does not understand the relevance of the IR reference to the question.

BC Hydro's *F2011 Demand Side Management Milestone Evaluation Summary Report* shows that industrial customers have a RS1823 Tier 2 price elasticity of demand of -0.16. While industrial customers tend to demonstrate more price-elasticity than other rate classes, an elasticity of demand that is between -1 and zero is defined as inelastic. Therefore, based on BC Hydro's F2011 report, industrial customers are price inelastic.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

1.9.11 Please confirm that each of the following customer types are typically price inelastic.

i. residential customers;

ii. SGS customers; and

iii. MGS customers.

If not confirmed, please fully explain your response.

RESPONSE:

BC Hydro does not understand the relevance of the IR reference to the question.

As discussed in BC Hydro's response to AMPC IR 1.9.10, customers are generally considered to be price inelastic with respect to energy consumption if elasticity of demand is between -1 and zero:

i. Step 2 price elasticity was found to be between -0.08 and -0.13 for Residential customers, as shown in the 2013 RIB Evaluation Report (Exhibit B-1 Appendix C-3B, page 109 of 609). Based on this finding, this class is price inelastic;

ii. Elasticity for SGS Customers has not been studied by BC Hydro. However, based on the non-residential demand studies used to support BC Hydro's 2008 LTAP (2008 LTAP, Appendix E, Table 3),[1] BC Hydro expects that SGS customers would have an elasticity between -1 and zero, and therefore would be price inelastic; and

iii. Elasticity for MGS customers has not been studied by BC Hydro. The F2014 LGS and MGS Evaluation Report (Exhibit B-1, Appendix C-4A beginning at page 399 of 813) estimated the conservation achieved for MGS but did not perform an econometric analysis to determine the elasticity of this class. However, based on the non-residential demand studies used to support BC Hydro's 2008 LTAP (Appendix E, Table 3), BC Hydro expects that MGS

[1] Copy available at http://www.bcuc.com/Documents/Proceedings/2008/DOC_18927_B-1_BCH%202008%20Long-Term%20Acquisition%20Plan.pdf.

customers would have an elasticity between -1 and zero, and therefore be price inelastic.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

1.9.12 Please provide the number of industrial customers that have ceased normal service under the Transmission Service rate class due to shut downs or for any other reason in 2015, and the associated aggregate load those customers represented before ceasing normal service.

RESPONSE:

During the period from January 1 to October 31, 2015, two transmission voltage customers permanently ceased normal operations. Prior to shutdown these customers represented a load in the order of 690 GWh per year.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

1.9.13 Is BC Hydro aware of any other utilities that include wholesale-type customers like New Westminster and FortisBC the same rate class as industrial customers. If so, please list all example BC Hydro is aware of, including the type of customer and the rate class they are included in.

RESPONSE:

BC Hydro is not aware of any Canadian utilities that include large wholesale-type customers in the same rate class as industrial customers.

Among U.S. utilities surveyed by the COS Consultants, Puget Sound Energy (PSE) has many sales for resale customers, including several with full requirements service. In PSE's COS analysis, PSE incudes its firm resale/special contracts together in a "customer class" that is comprised of municipal wholesale customers and Special Contract-Industrial Customers.

9.0 Topic: TRANSMISSION SERVICE RATE CLASS

Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

1.9.14 Please confirm that most utilities serve wholesale customers such as municipalities on a different rate schedule than industrial customers. If not confirmed, please fully explain your response.

RESPONSE:

BC Hydro has not surveyed the rates and terms and conditions applicable to municipalities and industrial customers at other utilities.

BC Hydro serves New Westminster and FortisBC on different rate schedules (RS 1827 and RS 3808) and on different terms and conditions than it does other Transmission Service customers (RS 1823).

10.0 Topic: CUSTOMER BASELINE LOADS

References: Exhibit B-1, Application, Appendix C-2C, Schedule 1.0, p. 11 of 79.
Exhibit B-1, Application, Appendix C-2C, Schedule 5.0, p. 22 of 79.
Exhibit B-1, Application, Appendix C-2C, Schedule 5.1, p. 23 of 79.

In Schedule 1.0, BC Hydro lists its planned costs that make up its revenue requirement.

In Schedule 5.0, BC Hydro provides its energy allocators for F10-F14, F16, and F13.

In Schedule 5.1, BC Hydro provides its demand allocators for F10-F14 and F13.

1.10.1 Please confirm if the "Energy @ Customer Meter" figures used in Schedule 5.0 of the Cost of Service Study reflect the full customer baseline load (CBL) energy of all transmission customers. If not, please provide the values that would be included in Schedule 5.0 if showing the full Energy @ the Customer Meter reflecting the full CBL energy for all transmission customers (i.e., assuming all CBL was being used) including a description of any necessary estimates or assumptions.

RESPONSE:

Not confirmed. The energy figures shown in Schedule 5.0 of the F2016 COS model, (Appendix E of Exhibit B-1) are based on forecast F2016 energy consumption by rate class.

If Schedule 5.0 F2016 Transmission Service energy consumption was replaced with "full CBL energy" the F2016 Transmission Service rate class would be assumed to use about 17,810 GWh per year.

Composition of Transmission Service Rate class energy purchases in F2016	F2016 COS Study (GWh)	F2016 COS Study Adjusted for Transmission Service Rate Class at "Full CBL Energy" (GWh)
RS 1827 Customers	948	948
FortisBC	541	541
DRTV Customers	13	13
RS 1823 (Customers with CBLs)	10,369	12,131[1]
RS 1823A (Customers without CBLs)	4,166	4,166
Other	11	11
Total	16,049	17,810

[1] **Based on F2014 Interim CBLs as approved by the Commission on November 29, 2013, Order No. G-197-13. Includes F2013 interim CBLs for certain customers if no F2014 CBL available.**

10.0 Topic: CUSTOMER BASELINE LOADS

References: Exhibit B-1, Application, Appendix C-2C, Schedule 1.0, p. 11 of 79.
Exhibit B-1, Application, Appendix C-2C, Schedule 5.0, p. 22 of 79.
Exhibit B-1, Application, Appendix C-2C, Schedule 5.1, p. 23 of 79.

In Schedule 1.0, BC Hydro lists its planned costs that make up its revenue requirement.

In Schedule 5.0, BC Hydro provides its energy allocators for F10-F14, F16, and F13.

In Schedule 5.1, BC Hydro provides its demand allocators for F10-F14 and F13.

1.10.2 Please discuss if there would be any revisions necessary to the Demand Allocators (Schedule 5.1) if the Schedule 5.0 was adjusted to reflect the full CBL of transmission customers (i.e., to ensure consistency between CBL energy and peak loads). If so, please provide a version of schedule 5.1 reflecting this assumption, including any estimates and assumptions necessary.

RESPONSE:

BC Hydro does not know how the individual Transmission Service customer peak demands or the Transmission Service rate class load profile would change if customers were hypothetically consuming at their "Full CBL Energy". Therefore, providing a revised version of Schedule 5.1 of Appendix E of Exhibit B-1 would be speculative. The impact on the Transmission Service rate class's 4CP allocation could be negligible (if customers increased their load factor by consuming more during non-peak winter periods) or it could be significant (if customers consumed more during peak winter periods).

10.0 Topic: CUSTOMER BASELINE LOADS

References: Exhibit B-1, Application, Appendix C-2C, Schedule 1.0, p. 11 of 79.
Exhibit B-1, Application, Appendix C-2C, Schedule 5.0, p. 22 of 79.
Exhibit B-1, Application, Appendix C-2C, Schedule 5.1, p. 23 of 79.

In Schedule 1.0, BC Hydro lists its planned costs that make up its revenue requirement.

In Schedule 5.0, BC Hydro provides its energy allocators for F10-F14, F16, and F13.

In Schedule 5.1, BC Hydro provides its demand allocators for F10-F14 and F13.

1. 1.10.3 Please discuss how the Planned Costs provided in schedule 1.0 of Appendix C-2C would change if BC Hydro were required (a) to serve the full CBL energy of all Transmission customers, and (b) to credit back to the Transmission class all costs incurred by Hydro (via foregone revenue) to acquire all assumed unused CBL energy at the Tier 2 rate (classified and allocated consistent with the treatment for IPP power acquisition). Please provide a revised version of Schedule 1.0 reflecting this assumption and a description of any estimates or assumptions used in preparing the analysis.

RESPONSE:

Under the approach described in the IR, BC Hydro would first assign energy costs to Transmission Service customers on a pro-rata basis using the F2016 COS embedded cost methodology. The Transmission Service rate class would then be credited the full value of any avoided costs resulting from reductions in RS 1823 Tier 2 energy purchases, which is a marginal COS concept.

BC Hydro cannot provide a revised Schedule 1.0 of the F2016 COS study (Appendix E, Exhibit B-1) because the approach described in the IR would be complex and onerous with a requirement to make many assumptions:

1. **It is not clear how reduced RS 1823 Tier 2 revenue should be treated, however it appears that AMPC is requesting direct DSM assignment for the Transmission Service rate class. BC Hydro rejected direct assignment of DSM costs in section 2.3 of the Workshop 2 consideration memo (pages 278-280 of 439, Appendix C-2A, Exhibit B-1) because it fails to recognize that all customers benefit from DSM energy and capacity savings. BC Hydro does not allocate the benefits of DSM as a result of RS 1823 solely to the Transmission Service rate class, because all customers benefit when costs are avoided as a result of lower Tier 2 purchases. Adopting the approach suggested in this IR would at a minimum likely necessitate some form of direct assignment of RIB rate-related savings.**

2. **It is not clear how much additional cost should be added to Schedule 1.0 if Transmission Service customers hypothetically consumed at full RS 1823 CBL (about 12,000 GWh) rather than the F2016 forecast (about 10,300 GWh):**

- **Some of these costs may already be reflected in Schedule 1.0 since BC Hydro may have surplus generation that could first be used to serve full RS 1823 CBL load before additional resources are contracted;**

- **Some of these costs are likely IPP or DSM-related. The proportion of different resource costs to hypothetically serve full RS 1823 CBL load is unknown; and**

- **It would also be complex to determine how much of the value of any avoided costs resulting from reductions in Tier 2 energy purchases should be credited to the Transmission Service rate class. Not all of the reduction in Tier 2 energy purchases is the result of DSM (e.g., economic down-cycle).**

4. **The approach raises fairness concerns. After F2018, and assuming that the MGS and LGS rates are flattened, only the Transmission Service rate class would benefit from the approach as no other rate class would have customer specific baseline rates. Consequently, the Transmission Service rate class would benefit from energy savings originating from other rate classes, but not the other way around.**

5. **Finally, BC Hydro is unaware of any jurisdiction that uses the proposed approach in an embedded COS study.**

From: Sarah Khan <SKhan@bcpiac.com>
Sent: Tuesday, November 17, 2015 7:16 PM
To: Commission Secretary BCUC:EX; 'bchydroregulatorygroup@bchydro.com'
Cc: dwcraig@allstream.net; 'acpullman@shaw.ca'; Sopinka, Amy MEM:EX; 'apeacock@telus.net'; 'bharper@econalysis.ca'; cweafer@owenbird.com; 'bob@creativeharmonicsolutions.com'; 'cao@hudsonshope.ca'; 'cbefire@telus.net'; 'cdalori@shaw.ca'; 'daustin@cwilson.com'; 'dramage@shaw.ca'; 'dsnoble@shaw.ca'; 'emcinnesrankin@yahoo.ca'; Erin Pritchard; 'fredweislaw@gmail.com'; 'gas.regulatory.affairs@fortisbc.com'; 'hansk@telus.net'; 'iknowjanis@shaw.ca'; 'IReeve@cope378.ca'; Buchanan, Jack MEM:EX; 'jaynepriest@gmail.com'; 'jejaervin@telus.net'; 'jo-anne.frank@prrd.bc.ca'; 'jquail@aqwlaw.ca'; 'jweimer@telus.net'; 'lworth@aqwlaw.ca'; 'mark.pinney@capp.ca'; 'mdk@bht.com'; 'mgood@midgard-consulting.com'; 'mildredl@telus.net'; 'orion.henderson@ubc.ca'; 'paul.kariya@cleanenergybc.org'; 'peter_kletas@yvr.ca'; 'pveacoordinator@gmail.com'; 'pvla@xplornet.com'; 'rbw@bht.com'; 'rcarle@newwestcity.ca'; 'roger.bryenton@earthlink.net'; 'roger@fsconline.com'; 'roninconsult@live.com'; 'rsue@sfu.ca'; 's.ridout@shaw.ca'; BCPIAC Support; 'thackney@shaw.ca'; 'william.harper4@sympatico.ca'; 'wjandrews@shaw.ca'; 'pmiller@boughtonlaw.com'
Subject: BC Hydro 2015 RDA - BCOAPO IR1
Attachments: 7615_20151117_BCH RDA 2015 - BCOAPO IR #1.docx; 7615_20151117_BCH RDA 2015 - BCOAPO IR #1.pdf

Attached please find information requests on behalf of BC Old Age Pensioners' Organization et al.

For the purposes of these information requests, we are defining "low income customers" to mean BC Hydro Residential customers with a before tax annual household income equal to or less than the low income cut-off established by Statistics Canada (LICO). LICO is used in the 2015 RDA engagement modelling and the 2014 REUS. However, since "low income household" is defined in the Demand Side Measures (DSM) Regulation as households at or below LICO plus 30%, many of our DSM-related questions use the DSM Measures Regulation definition of low income.

Please contact us if you have any questions about the definition of "low income" in these information requests.

Sarah Khan
Barrister & Solicitor
BC Public Interest Advocacy Centre
208-1090 West Pender St., Vancouver, BC V6E 2N7
Coast Salish Territory
Ph: 604-687-4134
Fax: 604-682-7896

REQUESTOR NAME:	BCOAPO
INFORMATION REQUEST ROUND NO:	1
TO:	BRITISH COLUMBIA HYDRO & POWER AUTHORITY
DATE:	November 17, 2015
APPLICATION NAME:	2015 Rate Design Application (2015 RDA)

TABLE OF CONTENTS PAGE **PAGE**

A. CHAPTERS 1 – INTRODUCTION…….....2

B. CHAPTER 2 – STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY……..…3

C. CHAPTER 3 – COST OF SERVICE…….....7

D. CHAPTER 4 – RATE CLASS DETERMINATION ……..13

E. CHAPTER 5 – RESIDENTIAL RATE DESIGN……15

F. CHAPTER 6 – GENERAL SERVICE RATE DESIGN……37

G. CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN……42

H. CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS……46

REQUESTOR NAME:	BCOAPO
INFORMATION REQUEST ROUND NO:	1
TO:	BRITISH COLUMBIA HYDRO & POWER AUTHORITY
DATE:	November 17, 2015
APPLICATION NAME:	2015 Rate Design Application (2015 RDA)

CHAPTER 1 - INTRODUCTION

1.0 Reference: Exhibit B-1, pages 1-18 and 1-19

Preamble: Default rates are rates that all customers pay unless they have options and choose to opt for another rate. (page 1-19)

1.1 Is there only one default rate (schedule) that is applicable to each Rate Class set out in Table 1-1?

1.1.1 If yes, please indicate for each class what that rate schedule is.

1.2 If there are rate classes where more than one default rate (schedule) applies, please indicate what these rate schedules are and describe the differences in the characteristics of the customers served under each.

1.2.1 Please explain why each of these separate groups of customers is not considered to be a “rate class” for purposes of the RDA.

2.0 Reference: Exhibit B-1, page 1-19

2.1 Please clarify, with reference to its Cost of Service Study (COS) results, what BC Hydro considers as “demand-related costs” (per line 24).

3.0 Reference: Exhibit B-1, page 1-20 and Section 2.2

Preamble: Section 1.5.1 makes reference to the Bonbright’s eight rate design criteria and then goes on to state that it prioritizes the three Bonbright rate design criteria set out in Table 1-2.

3.1 Please specifically describe how the factors identified in section 1.1.1 led to BC Hydro prioritizing the three Bonbright criteria set out in Table 1-2.

4.0 Reference: Exhibit B-1, page 1-21 & 1-21

4.1 How did BC Hydro determine the stakeholders that should be involved in its RDA workshop process?

5.0 Reference: Exhibit B-1, page 1-25

5.1 Please produce a schedule showing the derivation of the $950,000 impact to F2016 net income given that the updated Minimum

Reconnection Charge will be implemented on an interim basis on December 1, 2015.

6.0 Reference: Exhibit B-1, page 1-25

6.1 Please outline all instances where the F2016 COS was used to inform the rate design proposals set out in the current application.

CHAPTER 2 – STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

7.0 Reference: Exhibit B-1, page 2-4

7.1 Please describe how, if at all, the requirement under subsection 60(1)(b) "to encourage public utilities to increase efficiency, reduce costs and enhance performance" is reflected in the rate design criteria (page 1-20) and the other considerations underpinning the 2015 RDA proposals.

8.0 Reference: Exhibit B-1, page 2-4 through page 2-6

8.1 Please describe how, if at all, the British Columbia energy objectives (as set out in Section 2 of the *Clean Energy Act*) are relevant to the 2015 RDA and influenced BC Hydro's prioritization of the rate design criteria as set out in Table 1-2.

9.0 Reference: Exhibit B-1, Section 2.2, p. 2-5, Footnote 38
Rate Increases/Rate Caps

Preamble: The Application states the following:

> **"**The Rate Comparison Regulation, B.C. Reg. 119/2011 provides that BC Hydro is to provide the B.C. Minister of Energy and Mines with a report that includes a comparison of BC Hydro's rates with those of at least one public utility in each of 15 other jurisdictions in North America, including the provinces of Alberta, Manitoba, Ontario and Quebec, and the states of Washington, Oregon and California; https://www.canlii.org/en/bc/laws/regu/bc-reg-140-2009/latest/bc-reg-140-2009.html BC Hydro used the Rate Comparison Regulation to inform the scope of its various jurisdictional assessments as described in section 2.4.2of the Application"

9.1 Please provide a copy of the most recent Rate Comparison Report provided to the BC Minister of Energy and Mines.

10.0 Reference: Exhibit B-1, page 2-7

10.1 In BC Hydro's understanding/interpretation, do retail customers (lines 16-22) include transmission connected consumers?

11.0 Reference: Exhibit B-1, pages 2-13 and 2-14

11.1 Does BC Hydro consider the principles underlying the Domestic Long-Term Sales Contract Regulation (as they pertain to the treatment and

recovery of the costs of interconnecting to the BC Hydro transmission system and any system upgrades) to be of relevance to the Transmission Extension policy, which is the subject of 2015 RDA Module 2?

12.0 Reference: Exhibit B-1, pages 1-20, 2-14 and 2-23

12.1 Please explain why "encouraging" energy efficiency was not adopted as one of the prioritized rate design criteria, particularly in light of the residential focus group feedback (page 2-23, lines 22-23).

13.0 Reference: ExhibitB-1, page 2-16 (lines 9-16)

13.1 In BC Hydro's view, does the MEM Policy Letter require/obligate the Commission to exempt SFU and YVR from RS 1823 and other stepped rates?

14.0 Reference: Exhibit B-1, pages 2-22 to 2-23

14.1 Did the Residential Focus Group sessions canvas the participants as to any specific concerns they had regarding BC Hydro's residential rates?

13.1.1 If yes, what feedback was received?

15.0 Reference: Exhibit B-1, page 2-30 (lines 19-20)

15.1 What were the other three policy objectives that "grounded" BC Hydro's 1991 RDA?

15.2 Please discuss the extent to which each of the four policy objectives are applicable in the context of the 2015 RDA.

16.0 Reference: Exhibit B-1, pages 2-32 through 2-34

16.1 Have any of the Government responses set out in Table 2-2 been superseded or altered as result of subsequent government policy statements, regulations or legislation?

15.1.1 If yes, please indicate what the revised government response/position is.

17.0 Reference: Exhibit B-1, pages 2-37 to 2-39

17.1 Were there policy objectives that "grounded" BC Hydro's 2007 RDA?

16.1.1 If yes, what were they, and are they still applicable in the context of the current 2015 RDA?

18.0 Reference: Exhibit B-1, page 2-44

18.1 While BC Hydro's current load curtailment program is not viewed as a "rate" or a "service", would it not be possible for BC Hydro to design a rate for non-firm service (i.e., service that could be curtailed under certain circumstances) for transmission customers and for which the customers

would pay a different rate and that would qualify as rate and service under Section 1?

17.1.1 If not, please explain why?

17.1.2 If not, please explain how such an approach would differ, in principle, from the Residential E-Plus Rate.

19.0 Reference: Exhibit B-1, page 2-46

Preamble: BC Hydro notes that the standard economic technique used to determine LRMC is to calculate the minimum present-day view of the cost of meeting a permanent increment (or decrement) of demand.

19.1 It is noted that BC Hydro's calculation of LRMC is based on the cost of meeting an increment in demand. Would the calculation and resulting LRMC differ if the approach was based on the cost savings from a decrement in demand?

19.2 Will these resources (i.e. those listed at lines 22-25) also be sufficient to meet BC Hydro's capacity needs over the next 10 years?

18.2.1 If not, what other resources will need to be relied on?

20.0 Reference: Exhibit B-1, page 2-48, lines 1-10

20.1 Given that Site C comes into service in F2025, why is it not included in the list of resources (lines 6-10) being used to meet expected energy future energy needs?

21.0 Reference: Exhibit B-1, page 2-48, lines 18-27

21.1 Why are the RIB rate and RS1823 considered "future DSM initiatives" (per lines 26-27) when they are already in place?

21.2 What does the "Load Forecast Before DSM" shown in Figure 2-1 assume with respect to the existence and the impact of the Residential RIB rate and RS1823 in F2017 and beyond?

22.0 Reference: Exhibit B-1, page 2-49 to 2-50

Preamble: Given the 2015 RDA also discusses the treatment of capacity long-run marginal costs in determining the LRMC to be used for rate making it is necessary to fully understand the basis for the energy LRMC proposed by BC Hydro.

22.1 Please explain more fully what is meant by "net TRC" in the context of DSM programs. In particular, please clarify whether the participant and utility costs, which according to Footnote 95 form the basis for the overall TRC (economic cost) of DSM initiatives, have been reduced by netting out: a) generation capacity benefits, b) transmission capacity benefits, c)

distribution capacity benefits, d) non-energy benefits, and e) natural gas savings benefits.

22.2 What was the basis for the generation capacity benefit that was netted from the TRCs for the various DSM programs set out in Table 9-7 of the 2013 IRP?

21.2.1 If it differs from the UCC of Revelstoke Unit 6, please explain why.

21.2.2 If it differs from the UCC for Revelstoke Unit 6, please recalculate the net TRC values for each of the DSM programs using Revelstoke Unit 6 as the basis for the generation capacity benefit.

21.3 For each DSM program listed in Table 9-7 from the 2013 IRP please indicate the value (in both $/kW and $/kWh using the same F2013$ as Table 9-7)) attributed to each of the generation, transmission and distribution capacity benefits.

21.4 With respect to the net TRC values presented in Table 9-7 (from the 2013 IRP) please indicate: a) what period the values are levelized/calculated over, and b) whether the values represent the real LRMC values (in F2013$).

21.5 Please re-state the DSM options net TRC costs as shown in Table 9-7 in F2016$ so as to make them comparable with the EPA renewal costs cited on page 2-50.

23.0 Reference: Exhibit B-1, page 2-50, lines 1-6

23.1 Please clarify what is meant when the Application states that DSM Option 3 would “entail no changes to BC Hydro’s rate structures.”

23.2 The wording at lines 1-4 suggests that, as compared to DSM Option 3, Recommended Action 1 in the 2013 IRP does include “changes to BC Hydro’s rate structure”. Please confirm whether or not this is the case.

22.2.1 If yes, specifically what changes to BC Hydro’s rate structures were envisioned in Recommended Action 1 on DSM.

24.0 Reference: Exhibit B-1, page 2-54

24.1 Given the requirement of the *Clean Energy Act*, Section 2(c), is there a limit to the amount of natural gas-fired simple-cycle gas turbine generators that could be installed to meet generation capacity requirements?

23.1.1 If yes, how does this affect the use of SCGTs are a benchmark for capacity long-run marginal cost?

25.0 Reference: Exhibit B-1, page 2-55

25.1 Is it BC Hydro’s view that the LRMC used for rate making should not: a) include avoided transmission costs when considering RS 1823, and b)

should not include avoided transmission and distribution costs when considering the RIB rate?

25.2 What are the avoided transmission and distribution costs associated with Residential service? Please provide the F2013$ values both in $/kW and in $/kWh based on the Residential load profile?

25.3 What are the avoided transmission costs for RS1823 customers? Please provide the F2013$ values in both $/kW and $/kWh based on the load profile for transmission service customers.

25.4 Please provide revised versions of Tables 2-5 and 2-6 with an additional column that sets out the value for the Upper End of the Energy LRMC plus the Rev 6 UCC, adjusting for losses as necessary.

26.0 Reference: Exhibit B-1, pages 2-59 & 2-66

26.1 Please clarify whether in applying the 10% impact test, BC Hydro looks at the impact on: a) the most adversely affected customer in the entire Residential class, or b) the most adversely affected customer in its representative sample of 10,000.

25.1.1 If response is (b), please indicate (based on the last 12 months of available billing data) how many Residential customers use: i) less electricity than the customer in the representative sample with the lowest use and ii) more electricity than the customer in the representative sample with the highest use.

25.1.2 If response is (b), please indicate (based on the last 12 months of available billing data): i) what average monthly usage is for the lowest use Residential customer overall vs. the lowest use customer in the representative sample, and ii) what the average monthly usage is for the highest use Residential customer overall vs. the highest use customer in the representative sample.

CHAPTER 3 - COST OF SERVICE

27.0 Reference: Exhibit B-1, pages 3-1 & 3-37 and Appendix E, COSS – Schedule 4.1

27.1 With respect to Table 3-7, please provide a revised version that sets out for each Rate Class:

(a) The energy, demand and customer costs (in dollars) allocated per COSS Schedule 4.1;
(b) A breakdown of “customer costs” separating out that portion of the distribution system’s substations, primary system, transformers and secondary system that has been classified as “customer-related” and allocated to the rate classes;
(c) A breakdown of “demand costs” separating out that portion that is allocated based on 4CP vs. NCP;
(d) The F2016 customer count, billed energy and billing demand (where applicable) determinants by class as used in establishing the forecast revenues by customer class in the COSS per Appendix E;

(e) The ratio of: i) allocated energy costs per billing kWh (Note- for classes that are not billed using demand also include the demand costs in this calculation), ii) allocated demand costs per billing kW (for applicable classes) broken down per point (c), and iii) allocated customer costs broken down per point (b) per customer per month.

28.0 Reference: Exhibit B-1, page 3-6 (lines 20-22) and pages 3-7 to 3-11

28.1 The Application makes note of the Commission's decision regarding FortisBC's 2009 Rate Design/COS Application. Please indicate how the COS Methodology as proposed by BC Hydro for the 2015 RDA aligns with the Commission's directives in the FortisBC decision regarding COS methodology.

28.2 Please contrast how FortisBC's COS methodology (as approved by the BCUC) contrasts with BC Hydro's proposals with respect to the key issue areas noted at page 3-7 (lines 11-13).

29.0 Reference: Exhibit B-1, pages 3-11 and 3-36

29.1 Please provide the R/C Ratios that would result if the methodology approved in the 2007 RDA Decision was applied using the F2016 costs and updated load profiles/allocators as discussed on page 3-11, lines 9-18.

29.2 Using the COSS results per part (1), please provide a schedule that sets out for each Rate Class:

(a) The energy, demand and customer costs (in dollars) allocated;
(b) A breakdown of "customer costs" separating out that portion of the distribution system's substations, primary system, transformers and secondary system that has been classified as "customer-related" and allocated to the class;
(c) A breakdown of "demand costs" separating out that portion that is allocated based on 4CP vs. NCP;
(d) The F2016 customer count, billed energy and billing demand (where applicable) determinants by class as used in establishing the forecast revenues by customer class in the 2015 RDA; and
(e) The ratio of: i) allocated energy costs per billing kWh (Note- for classes that are not billed using demand also include the demand costs in this calculation), ii) allocated demand costs per billing kW (for applicable classes) broken down per (c), and iii) allocated customer costs broken down per point (b) per customer per month.

30.0 Reference: Exhibit B-1, page 3-12 to 3-13

30.1 Prior to 2013, did BC Hydro rely on load research work to develop the load profiles for all of its rate classes, or did some classes have interval metering for billing purposes from which the data could be used?

30.2 For each customer class please indicate the % of customers that have interval meters for billing purposes.

30.3 Does the enhanced 45,000 sized sample yield 1% accuracy at the 99% level for all rate classes?

31.0 Reference: Exhibit B-1, page 3-14

31.1 Please provide a copy of the analysis supporting BC Hydro's determination that the actual GRTA costs ranged between $42.6 M and $44.2 M in the F2012-2014 period.

31.2 Please briefly describe how functionalizing these costs as generation costs as opposed to transmission changes their classification and allocation to customer classes.

32.0 Reference: Exhibit B-1, page 3-14

32.1 Does BC Hydro receive transmission-related revenues for Powerex's use of its transmission system to make energy sales?

32.2 If yes, are these revenues treated as an offset to the costs functionalized as transmission in the COSS?

33.0 Reference: Exhibit B-1, page 3-15 to 3-19

33.1 Please provide a schedule that lists BC Hydro business groups (at the level of detail shown in the RRA financial model, Schedules 5.1 to 5.4), their O&M costs for F2016, and the functional area(s) to which they were mapped. For those business groups that provide services to multiple functional areas, please indicate all of the functional areas involved and what % of the total costs are actually attributable to the functional area the costs are mapped to in the COSS.

33.2 Please confirm that the approach outlined at 3-17, lines 12-14 was used for Corporate Groups which effectively support all areas of the Corporation (e.g. Executive, Human Resources, SH&E and Finance) and not the approach set out at page 3-15, lines 20-22.

33.3 How were the taxes assigned to the Corporate Groups in the RRA financial model functionalized in the COSS?

33.4 Would a bottom-up approach for O&M, including IT operating costs (as described on page 3-16 and 3-17) have a material (>5%) impact on the quantum of energy vs. demand vs. customer-related costs allocated to each rate class?

34.0 Reference: Exhibit B-1, page 3-15 to 3-22

Preamble: The written Application does not appear to explain how the Non-Tariff, Inter-Segment and Other Utility Revenue shown in the RRA financial model (Schedule 1, lines 7, 8 & 20) were functionalized.

34.1 Please describe the sources of Non-Tariff, Inter-Segment and Other Utility Revenue for F2016 and indicate how they were functionalized, with supporting rationale.

35.0 Reference: Exhibit B-1, page 3-19

35.1 What is the rationale for the specific Generation, Transmission and Distribution percentages used in the functionalization of DSM costs?

36.0 Reference: Exhibit B-1, page 3-21 and 3-27

36.1 Please provide the rationale for the change in the classification of interest on deferral accounts as described at lines 10-13.

36.2 Please provide a schedule that set out the classification approach for: a) the Recovery associated with the TIDA and b) the interest on each of the TIDA. In doing so please indicate specifically where in Appendix E the classification for each is found.

36.3 If the classification of the recovery is not the same as for the classification of the interest, please explain why different methodologies are used for each.

36.4 Please provide a schedule that sets out the classification approach for: a) the Recovery associated with the TIDA and b) the Powerex Net Income. In doing so, please indicate specifically where in Appendix E the classification of each is found.

35.4.1 If the classification approaches are different, please explain why.

37.0 Reference: Exhibit B-1, pages 3-23 to 3-25

37.1 Throughout section 3.7.1, frequent use is made of the term “Generation”. Please confirm that in each case the reference is to “Heritage Hydro Generation”. For example, in lines 7-8, please confirm that BC Hydro is expressing a preference for a 55% energy/45% demand split for Heritage Hydro Generation and not all Generation.

37.2 How does the choice between classification methods for Heritage Hydro Generation impact the quantum of energy vs. demand-related costs allocated to each rate class? Please provide a schedule that sets out separately the Generation Demand and Energy Costs that are allocated to each rate class using each method, where Total Generation cost will be the ($2,595.3 M) shown in the COSS, Schedule 2.0.

37.3 Does the system load factor calculation used for Heritage Hydro Generation exclude the load in the Fort Nelson Service Territory?

36.3.1 If not, why not given that FNG (like IPPs) is classified separately?

38.0 Reference: Exhibit B-1, page 3-25 and Appendix E, F2016 COSS - Schedule 2.0

38.1 At page 3-25 BC Hydro proposes different classification treatments for each of FNG, PRG and Burrard as compared to that proposed for Heritage Hydro Generation. However, in Schedule 2.0 all Thermal O&M costs are classified on the same basis as Heritage Hydro Generation. Similarly, all Depreciation, Taxes and Finance charges associated with

Generation (including Thermal Generation) are classified on the same basis as Heritage Hydro Generation. Please reconcile and clarify what classification was used for Heritage Thermal Generation.

38.2 Please set out separately the classification of the costs (excluding Fuel) for each of FNG, PRG and Burrard using the approaches described at page 3-25.

39.0 Reference: Exhibit B-1, page 3-27 (lines 1-3) & pages 2-47 to 2-49 and Appendix E, F2016 COSS - Schedule 2.0

39.1 At page 3-27 it states that BC Hydro believes the classification of Generation-related DSM costs should mirror the classification of overall Generation costs. However, in Schedule 2.0 of the COSS all Generation-related Depreciation and Amortization (including that for DSM) is classified on the same basis as Heritage Hydro Generation (45%-D/55%-E). Please reconcile.

39.2 Please confirm that the alternatives to DSM are undertaking IPP EPA renewals and initiating new green-field IPP clean or renewable acquisition processes.

38.2.1 If not confirmed, what are the alternatives to DSM?

38.2.2 If confirmed, why wouldn't it be more appropriate to classify Generation-related DSM using the same percentages for demand and energy as proposed for IPPs?

40.0 Reference: Exhibit B-1, pages 3-27 to 3-29; Appendix C-2A – Leidos Report (December 2013) and Reimer Report (May 2010)

40.1 Please provide a schedule that indicates the proposed methodology and resulting classification percentages for Substations, Primary, Transformers, Secondary, Services and Services as recommended by each of the consultants (Leidos and Reimer).

40.2 The 2015 RDA states (page 3-28) that the COS consultants recommended approach (3) – use of professional judgement to separate demand-related and customer-related distribution costs. Please provide the relevant references for the Leidos and Reimer Reports where this recommendation can be found.

40.3 At page 3-29 BC Hydro states that Bonbright rejects the minimum system and zero-intercept methodologies. What approach does Bonbright view as being acceptable?

40.4 Please re-do Tables 27 and 28 from the Reimer Report using the F2016 Revenue Requirement and BC Hydro's' proposed functionalization (and sub-functionalization) of costs. Please add a row to each Table reflecting BC Hydro's recommended approach for each Distribution "sub-function".

40.5 Please provide a new Schedule based on the results from part (4) that sets out the total demand and total customer-related costs allocated to

each rate class based on each of the seven methods (i.e., the 6 reported in the original Table 28 plus BC Hydro's approach).

41.0 Reference: Exhibit B-1, pages 3-29 to 3-30

41.1 Does the choice of classification methods for SMI materially impact the quantum of energy vs. customer-related costs allocated to each rate class?

42.0 Reference: Exhibit B-1, page 3-31

42.1 Is the same 6% distribution loss factor used for all distribution customers regardless of their service voltage?

42.1.1 If yes, do all distribution customers have the same notional metering point (i.e., the point at which energy is assumed to delivered and measured for billing purposes)?

43.0 Reference: Exhibit B-1, page 3-33 and 3-13

43.1 For the current 2015 RDA, for how many of the five years of data used in determining the NCP values was based on the broader sample of data available from SMI reads vs. load research work.

43.2 For the Residential class, please provide the ratio of 1 NCP (kW) to total energy (kWh) for each of the five years used in the averaging and indicate which years are based on SMI reads.

44.0 Reference: Exhibit B-1, pages 3-34 to 3-35

44.1 Please provide a schedule that sets out all of the COSS methodology changes as between the 2007 RDA (as approved by the Commission) and the currently proposed methodology.

45.0 Reference: Exhibit B-1, pages 3-33 to 3-34 and Appendix E, COSS – Schedules 3.2

Preamble: Schedule 3.2 reports Distribution Transformer-related costs of $142.7 M and calculates the value by applying the percent of distribution assets (excluding street lighting) that are accounted for by transformers for Sheet 6.0 to the difference between the values reported in Schedule 2.2 at cells D76 and D73. In principle these two cells should represent the total value of all distribution assets and the total value of street lighting assets respectively. However, D73 represents the Internal Allocations functionalized as Distribution and H76 represents the costs directly assigned to Street Lighting. There appears to be a similar issue with the calculation of the values reported in cell F5.

45.1 Please review the formulae used in Schedule 3.2 and address the issues outlined in the preamble.

46.0 Reference: Exhibit B-1, pages 3-33 to 3-34 and Appendix E, COSS – Schedules 5.4

46.1 Please explain how the breakdown between OH and UG transformers set out in Row 12 was done.

46.2 Please confirm that the allocation to rate classes was done use Option 1 (Direct Assignment) per the October 7, 2014 Workshop Presentation.

45.2.1 If not, how was the allocation performed?

47.0 Reference: Exhibit B-1, pages 3-33 to 3-34 and Appendix E, COSS – Schedules 6.0

47.1 With respect to the year-end asset values used in Schedule 6.0, please clarify whether these are gross or net book values and whether or not they are net of capital contributions received from third parties.

47.2 Please explain why the asset value selected is appropriate for assigning to Distribution sub-functions each of the following:

(a) Operating Costs;
(b) Depreciation; and
(c) Financing Costs.

48.0 Reference: Exhibit B-1, pages 1-1 & 1-2, and Section 3.1.2 Rate Increases and next Rate Design Application

48.1 BC Hydro states that rate caps will be in place until 2019, and that it will file an F2019 COS. When does BC Hydro expect to file its next RDA?

48.2 Will the next RDA be filed as part of the proposed F2019 COS?

48.3 What are BC Hydro's projected rate increases for 2016-2025?

CHAPTER 4 – RATE CLASS DETERMINATION

49.0 Reference: Exhibit B-1, pages 4-3 to 4-5 and 4-8

Preamble: At page 4-8, BC Hydro states that "Low load factors are indicative of customers that are more costly to serve, and load factor is therefore a consideration when evaluating rate class segmentation". Given this acknowledged relationship between load factor and cost to serve, information regarding load factor characteristics of customers within a class may also be useful for rate design and well as class segmentation purposes.

49.1 Please provide an assessment of the relationship between individual Residential customers' annual energy use and load factor that indicates whether there are any changes in load factor as annual energy use increases and, if so, where the "break points" exist. In doing so, please calculate using each of the following definitions of load factor:

49.1.1 Total average energy use vs. a customer's demand coincident with overall system peak demand (4CP).

49.1.2 Total average energy use vs. a customer's demand coincident with the Residential class NCP.

50.0 Reference: Exhibit B-1, page 4-5 and 5-51

Preamble: BC Hydro concludes that the impact of making Residential E-Plus customers a separate class was too insignificant to justify such a change.

50.1 What is the annual energy use of Residential E-Plus customers?

50.2 Page 5-51 discusses the R/C ratios for portions (i.e., heating and non-heating load) of Residential E-Plus customers' load but not overall values. If Residential E-Plus customers were a separate rate class what would be its overall R/C ratio under the following two circumstances:

(a) Generation energy costs are not assigned to Residential E-Plus heating load; and
(b) Generation energy costs are assigned to Residential E-Plus heating load.

50.3 Given the proposed changes to the terms and conditions for Residential E-Plus, what would be its overall R/C ratio if no energy or capacity related costs were allocated?

51.0 Reference: Exhibit B-1, page 4-9 (lines 5-13)

51.1 In 2009, did E3 recommend a breakpoint for the LGS vs. MGS classes and, if so, what was it?

52.0 Reference: Exhibit B-1, page 4-10 (lines 6-19)

Preamble: BC Hydro concludes at lines 11-12 that "a customer's coincident peak demand is a major consideration in segmenting customer classes". However, at lines 17-19, BC Hydro also concludes that "since distribution costs are assigned proportionate to NCP, the cost per NCP kW does not vary and a $/kW analysis cannot be used to identify cost differences between segments".

52.1 Please confirm that for Generation and Transmission demand costs the costs are assigned proportionate to 4CP and the costs per 4CP does not vary by the customer's size.

52.2 Please explain why a customer's coincident peak demand is considered a major consideration in segmenting classes but a customer's contribution to NCP cannot be used.

53.0 Reference: Exhibit B-1, page 4-12

53.1 With respect to Figure 4-2 please clarify whether the coincident demand costs for each group are divided by a) the NCP for the group or b) the sum of the maximum monthly demands for each customer in the group (i.e., total billing demand for the group).

53.1.1 If NCP was used, please explain why this appropriate/relevant for segmentation purposes.

53.1.2 If NCP was used, please re-do Figure 4-2 where the coincident demand costs for each group are divided by the billing demand for the group (i.e. the sum of the peak demands of the individual customers).

53.2 Please provide a figure, similar to Figure 4-2 where the Distribution-demand related costs that would be allocated to each segment are divided by the billing demand for the group.

53.3 Please provide a figure, similar to Figure 4-2, where the sum of the Generation-related demand costs, Transmission costs and Distribution-related demand costs that would be allocated to each group is divided by the billing demand for the group.

54.0 Reference: Exhibit B-1, page 4-18 and Appendix C-5A, page 137 of 292

54.1 With respect to the analysis presented in Workshop 5 (lines 20-24), please clarify how the load factor was determined for each customer and, in particular, what was used as the denominator in the calculation (e.g. was it the individual customer's average maximum monthly demand?).

55.0 Reference: Exhibit B-1, page 4-19 and Appendix C-1B, page 40 of 115

55.1 Please provide a revised version of the table at slide 40 that indicates for each of the 15 segments, the percentage of total energy purchases that were Tier 2 purchases.

56.0 Reference: Exhibit B-1, pages 4-26

56.1 BC Hydro notes that the nature of the service is similar as between RS1702, RS1703 and RS 1704. However for RS 1703 BC Hydro owns the pole whereas for the other two rate schedules it does not. Does BC Hydro plan to account for this difference in its examination of street lighting rate design as part of RDA Module 2?

56.2 Will BC Hydro take into account in considering the creation of two street lighting customer classes the fact that some customers currently on RS 1755 own the pole whereas in other cases they do not?

CHAPTER 5 – RESIDENTIAL RATE DESIGN

57.0 Reference: Exhibit B-1, page 5-3

57.1 Please provide a schedule that sets out the MWh of conservation delivered by the RIB rate in each of the years up to (and including) F2015.

58.0 Reference: Exhibit B-1, page 5-5

58.1 With respect to lines 8-12, how were the Step 1 and basic charge jointly set so as to achieve revenue neutrality?

58.2 Please provide a schedule that sets out the monthly usage by Residential customers (overall) broken down by each 10th percentile of increasing customer use. (i.e., what is the monthly usage below which 10% of customers fall, 20% of customers fall on up to 90% and then 100%).

58.3 Please provide a similar schedule to that in part (2) but for low income customers.

59.0 Reference: Exhibit B-1, page 5-10 to 5-12

59.1 Please explain why all of the consumption statistics quoted are based on median use as opposed to average use.

57.1.1 In each case where the median value is quoted please provide the average value as well.

59.2 Please provide a schedule that set outs out the average and median consumption by dwelling type.

59.3 Please provide schedules that set for each of the regions:

(a) The number of accounts by dwelling type;
(b) The total consumption by dwelling type; and
(c) The median and average use by dwelling type.

59.4 Please provide a schedule that sets the median and average per account for dwellings with electric heating vs. non-electric heating.

59.5 Please provide schedules that set out for each region:

(a) The number of accounts with electric heating vs. non-electric heating;
(b) The consumption of the accounts with electric heating vs. non-electric heating; and
(c) The median and average use per dwelling for accounts with electric heating vs. non-electric heating.

59.6 For each region, by dwelling type please provide schedules that set out:

(a) The number of accounts with electric heating vs. non-electric heating;
(b) The consumption of the accounts with electric heating vs. non-electric heating; and
(c) The median and average use per dwelling for accounts with electric heating vs. non-electric heating.

60.0 Reference: Exhibit B-1, pages 5-12 to 5-14

Preamble: Each of the following questions refers solely to low income Residential accounts.

60.1 Please provide a schedule that sets out a breakdown of the number of low income customers by region, the consumption of low income customers by region and the resulting median and average use by region.

60.2 Please provide a schedule that set outs out the average and median consumption by dwelling type for low income customers.

60.3 Please provide schedules that set out the following for low income customers for each of the regions:

(a) The number of accounts by dwelling type;
(b) The consumption by dwelling type; and
(c) The median and average use by dwelling type.

60.4 Please provide a schedule that for low income customers sets the median and average per account for dwellings with electric heating vs. non-electric heating.

60.5 Please provide schedules that for low income customers set out for each region:

(a) The number of accounts with electric heating vs. non-electric heating;
(b) The consumption of the accounts with electric heating vs. non-electric heating; and
(c) The median and average use per dwelling for accounts with electric heating vs. non-electric heating.

60.6 For each region, by dwelling type please provide schedules that for low income customers set out:

(a) The number of accounts with electric heating vs. non-electric heating,
(b) The consumption of the accounts with electric heating vs. non-electric heating, and
(c) The median and average use per dwelling for accounts with electric heating vs. non-electric heating.

61.0 Reference: Exhibit B-1, page 5-17 and Appendix C-3B, page 132 of 609

61.1 If customers with bi-monthly use of 1,350 to 2,400 kWh have a Step 2 price elasticity of -0.13 and customers over 2,400 kWh have a Step 2 price elasticity of -0.16 to -0.18, then how can the overall Step 2 price elasticity be in the range of -0.08 to -0.13?

62.0 Reference: Exhibit B-1, pages 5-24 – 5-25

62.1 Please provide a plot similar to Figure 5-14 for each of the following (total as well as by region if practical):

(a) Apt & Electric Heat;
(b) Apt. & Electric Heat & LI;

(c) Single Detached & Electric Heat; and
(d) Single Detached & Electric Heat & LI.

62.2 Please provide Tables similar to 5-3 and 5-4 for each of the results set out in part (1).

63.0 Reference: Exhibit B-1, pages 5-26 to 5-27

63.1 Which participants did not support only advancing Three Step A for purposes of the RDA?

63.2 Which participants' comments were given the most weight in determining what alternatives should be advanced to the 2015 RDA and why?

63.3 Does BC Hydro consider the Energy LRMC (Upper Limit) plus the UCC of Revelstoke 6 to be the relevant maximum value for LRMC for purposes of the 2015 RDA for all customer classes? If not, what is the maximum value for each class and why?

63.4 Please provide separate versions of Figure 5-16 that just include:

(a) Low Income Customers
(b) Low Income Customers with Electric Heat

64.0 Reference: Exhibit B-1, page 5-31

64.1 What percentage of low income customers with electric heat are better off under the Three Step A alternative as compared to the existing RIB rate?

65.0 Reference: Exhibit B-1, page 5-34 to 5-35 and page 5-30

Preamble: Page 5-30 provides an assessment of Option 1 against the Bonbright criteria based on expected F2017 rates.

65.1 Based on the anticipated rates for F2018 and F2019 please provide a comparative analysis of Options 1 and 2 using the Bonbright Criteria.

66.0 Reference: Exhibit B-1, page 5-35

66.1 Please provide the rates that would result from a 3rd Option (Option 3) where the Step 2 rate is increased at inflation and the Step 1 rate is increased so as to maintain revenue neutrality.

66.2 Please provide the equivalent to Figures 5-20 through 5-24 and Tables 5-9 & 5-10 based on this option.

67.0 Reference: Exhibit B-1, pages 5-41 to 5-42 and Appendix C-3B, page 29 of 609

67.1 What percentage of customer-related costs did the Residential basic charge recover at the time of the last RDA?

67.2 Please clarify what is meant by customer-related costs and indicate what the dollar value for customer-related costs is for the Residential class

based on the F2016 COSS, providing the necessary cross-references to the F2016 COSS – per Appendix E.

67.3 Based on the F2016 Residential billing determinants (i.e., customers and energy) please provide the calculations demonstrating that the current F2016 basic charge recovers 45% of customer-related costs.

67.4 It is noted that Slide 28 from Workshop 9a uses the term "fixed cost" as opposed to "customer-related costs". What is the definition of fixed costs used in this context, is it the same as BC Hydro's definition of customer-related costs and, if so, how has BC Hydro ensured the definitions are comparable?

68.0 Reference: Exhibit B-1, pages 5-42 to 5-43

68.1 Please provide, with reference to the COSS in Appendix E, the calculation indicating $15 is roughly equivalent to the average fixed distribution and customer-related cost per month.

69.0 Reference: Exhibit B-1, page 5-44 to 5-45

69.1 Are the values used in Figure 5-25 and Table 5-11, actual or weather normalized?

69.2 If actual, please provide a comparable figure using weather normalized values.

69.3 If median use on a weather normalized basis is not available, please provide average weather normalized use for each of the seven years.

69.4 Please repeat Figures 5-26 and 5-27 for customers:

(a) In Apartments;
(b) In Single Family Dwellings;
(c) With Electric Heating;
(d) In Single Family Dwellings with Electric Heating; and
(e) In Apartments with Electric Heating.

70.0 Reference: Exhibit B-1, Section 5.2
Residential Inclining Block (RIB) Rate

70.1 Please provide the most recent study showing the month-by-month load curve:

(a) For residential customers as a whole for a complete 12-month period;
(b) For each residential tariff class for a complete 12-month period;
(c) For low-income residential customers for a complete 12-month period;
(d) For low-use residential customers, who are also low-income; and
(e) For low-use residential customers, whether or not such customers are low-income, using whatever definition of "low-use" BC Hydro has utilized.

71.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

71.1 Please provide a detailed description of how BC Hydro identified its "low-income customers" in its consideration of the impacts of varying residential rate structures (see, e.g., page 5-23: "only 9 per cent of low income customers would be better off under a flat rate as compared to the RIB rate").

72.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

72.1 Please provide a copy of any study, memo, evaluation or analysis of any nature that discusses, assesses or otherwise considers the differences in the load curve for residential customers depending on the:

(a) Monthly kWh consumption of the customer;
(b) Annual kWh consumption of the customer; and
(c) Income of the customer.

73.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

73.1 In an active Excel spreadsheet:

(a) By month for the most recent twelve months available, disaggregated by heating and non-heating customers, provide a usage distribution in blocks of 50 kWh of consumption with a reasonable top-end usage block determined by BC Hydro. For each usage block identified, provide: (1) the number of accounts in the block; (2) the total consumption in kWh in the block; (3) the average usage in the block; (4) the bill for the average consumption at existing standard residential rates; and (5) the bill for the average consumption at the standard residential rates as proposed by BC Hydro in this proceeding;
(b) Provide the same information for low-income customers;
(c) Provide the same information for customers with annual consumption 80% of median or below; and
(d) Provide the same information for customers with annual consumption 130% of median or above.

74.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

74.1 In an active Excel spreadsheet:

(a) For each month for the most recent twelve months available, disaggregated by heating and non-heating residential accounts, please provide the average bill for residential accounts provided in sufficient detail (including all input variables) to permit replication; and
(b) Provide the same bill information with the RRA increases applied to all 3 rate elements rather than BC Hydro's existing rates"?

75.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

75.1 Please identify the objectives BC Hydro seeks to accomplish or achieve with a Residential Inclining Block rate structure. Place these objectives in rank order if they are not of equal importance.

76.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

76.1 Please identify what level of monthly usage (in kWh) is required to meet residential essential needs in a non-electric space heating household. Identify each end-use included in this essential needs and the monthly usage assumed for each such end-use.

77.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

77.1 To the extent that average monthly residential usage exceeds the essential needs usage identified in the response to the Information Request immediately above, please identify what end uses are included in the average but not in the essential needs. Identify both the end-use and the usage (in kWh) associated with that end-use.

78.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

78.1 Please indicate whether the level of usage to meet essential needs as identified in response to Information Requests above varies based on the income of the customer.

120.1.1 If yes, provide a detailed explanation of how, why, and to what extent such variation exists.

79.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

79.1 Please identify and provide a copy of all instances where BC Hydro has used any of the following metrics in measuring the targeting of rate relief delivered through a universal (in contrast to a means-tested or income-targeted) RIB rate:

(a) The beneficiary incidence as defined by the World Bank in assessing inclining block rate utility structures;
(b) The benefit incidence as defined by the World Bank in assessing inclining block rate utility structures;
(c) Omega (Ω) defined by the World Bank as the share of the subsidy benefits received by the poor divided by the proportion of the population in poverty; and
(d) To the extent previously used by BC Hydro, indicate whether its use distinguished between heating and non-heating customers.

80.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

80.1 To the extent that the BC Hydro analysis referenced and provided in response to the Information Request immediately above found an Omega less than 1.0, please provide all analyses by BC Hydro or others postulating, evaluating or otherwise discussing why an Omega of this value was present.

81.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

81.1 Please confirm or deny whether higher residential usage is associated with higher contributions to peak demand on BC Hydro's system, if heating and non-heating accounts are considered separately. If denied, provide a detailed explanation of the basis for that denial.

82.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

82.1 Please provide a copy of all written documents of any nature within BC Hydro's custody or control, if any, which empirically establish that peak kW demand may be less responsive to changes in price than kW of demand at other times.

83.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

83.1 Please indicate BC Hydro's agreement or disagreement with each of the following statements. If there is disagreement, provide a detailed explanation of the basis for each disagreement.

(a) Households with air conditioning tend to be more price responsive than those without;
(b) Consumption in peak periods is more elastic than consumption in off-peak periods, in the context of time varying tariffs; and
(c) Peak and off-peak consumption tend to be substitutes—a rise in the peak period price tends to lead to shifting of consumption away from the peak and into the off-peak period.

84.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

84.1 For BC Hydro's preferred default residential rate (i.e. the existing RIB rate), please indicate the monthly break-even point of usage, where a customer is neither better off nor worse off compared to a flat rate structure.

85.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

85.1 For the recommended Residential Inclining Block rate in BC Hydro's application, provide in an active Excel spreadsheet, in usage increments of 100 kWh, using the maximum usage level in each increment and a

reasonable top-coded usage block, whether customers in that usage block are “winners” or “losers,” and the amount of gain or loss.

86.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

86.1 Provide separate monthly usage distribution curves for low-income customers (as previously defined) and non-low-income customers (or residential customers irrespective of income if non-low-income is unavailable). Identify the usage amount at which the right tail of the low-income population intersects the left tail of the non-low-income population, if at all.

87.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

87.1 For each usage distribution curve provided in response to the Information Request immediately above, identify the upper and lower bounds of usage at which BC Hydro determines the steeply sloping portion of the demand curve becomes the flat portion. If a single point (called a “kink”) can be identified, identify the point of usage representing that kink for each curve.

88.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

88.1 In an active Excel spreadsheet, disaggregating by heating and non-heating customers, by monthly from January 2010 to present inclusive, provide the:

(a) Residential usage at the average (mean);
(b) Residential usage at the median;
(c) Residential usage at 50% of the median;
(d) Residential usage at 70% of the median;
(e) Residential usage at 125% of the median; and
(f) Residential usage at 150% of the median.

89.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

89.1 Please provide all written documents of any nature in which BC Hydro assesses, evaluates or otherwise discusses the relative impacts of delivering low-income bill relief by a RIB rate with a smaller initial block and a deeper discount relative to a RIB rate with a broader initial block and a shallower discount.

90.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

90.1 In an active Excel spreadsheet, please provide, disaggregated by heating and non-heating customers, a usage distribution by month for the most recent 12 months available, in the smallest bins used by BC Hydro to determine usage distributions, broken down by quintiles of residential

consumption. In this data, the "first quintile" would be the quintile with the lowest average annual consumption for the 12 months studied; the "fifth quintile" would be the quintile with the highest average annual consumption for the 12 months studied. BC Hydro can determine a reasonable top-coded usage amount. For each usage bin, provide:

(a) The number of accounts in each bin;
(b) The aggregate consumption in each bin; and
(c) The average consumption in each bin.

91.0 Reference: Exhibit B-1, Section 5.2, Figure 5.2
RIB Rate

Preamble: Figure 5.2 in the Application shows Average Residential Class Consumption by Month for F2011 to F2015.

91.1 Please provide separate graphs similar to Figure 5.2 for each of the following regions: Vancouver Island, Lower Mainland, Southern Interior, and the North.

91.2 Please provide any available data on average or median energy use on reserves per household, using the same format as Figure 5.2 to display the data.

92.0 Reference: Exhibit B-1, Section 5.2
RIB Rate

92.1 How many BC Hydro customers currently use more than 2000, 2100, 2200, 2300 and 2400 KWH per month on average? Please provide the answer in the form of a chart/graph, broken up by month.

134.1.1 Please provide a separate chart/graph for each of the following geographical regions: Vancouver Island, Lower Mainland, Southern Interior, and the North.

93.0 Reference: Exhibit B-1, Section 5.2, p. 5-29
RIB Rate

Preamble: BC Hydro states in the Application that it "advised Workshop 9a/9b participants of the outcome of the California Public Utilities Commission's (CPUC) June 21, 2015 residential rate reform plan, which will see the current four step residential rates of the three large investor owned utilities - Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric - reduced to two steps."

93.1 Please confirm the California utilities referenced above are moving to a two tier structure with a surcharge for high consumption.

94.0 Reference: Exhibit B-1, page 5-48 and 2-46

94.1 Do all current Residential E-Plus customers have smart meters with RDR capability?

94.2 If not, what is BC Hydro's proposed treatment from those who do not?

95.0 Reference: Exhibit B-1, page 5-51

95.1 For purposes of the COSS set out in Appendix D were the Residential E-Plus heating loads included in the determination of the energy and demand allocators for the Residential class?

71.1.1 If yes, what would be the impact of excluding them?

96.0 Reference: Exhibit B-1, pages 5-54 to 5-56

96.1 Under Option 3, is there any reason to maintain the Residential E-Plus rate as closed to new participants?

72.1.1 If yes, why?

96.2 With respect to notice of interruption (page 5-56), there is no reference to what is the shortest notice period that BC Hydro will provide. Does BC Hydro propose that there would be one and, if so, what would it be? Alternatively, could customers still be subject to interruption even if prior notice (as outlined at lines 26-27) has not been given?

97.0 Reference: Exhibit B-1, Section 5.4
Low income rate

97.1 If an income verification system is set up for low income Terms and Conditions of service, please confirm whether the same system could also be used for customers who are eligible for a lifeline rate?

98.0 Reference: Exhibit B-1, Section 5.4, p. 5-60
Low income rate

98.1 Does BC Hydro agree that the Manitoba Public Utilities Board found that affordability is a factor to consider in setting just and reasonable rates, as per the Public Utility Board's decision at p. 29?

99.0 Reference: Exhibit B-1, page 5-69 to 5-70

99.1 Based on the paragraph starting at line 25 of page 5-69, is dwelling size a factor in driving higher than average energy use?

99.2 For dwellings with electric heat, is either dwelling type or size a factor in driving higher than average energy use? Please provide the analysis supporting the response.

100.0 Reference: Exhibit B-1, page 5-70 to 5-71

100.1 With respect to page 5-71 (lines 14-21), what portion of Residential customers would see a bill decrease of greater than 10% if a flat energy rate were put in place as opposed to the current RIB rate?

100.2 With respect to page 5-71 (lines 14-21), what portion of low income Residential customers would see a bill decrease of greater than 10% if a flat energy rate were put in place as opposed to the current RIB rate?

101.0 Reference: Exhibit B-1, page 5-71

Preamble: Question 3 from the Minister's RIB Report Letter inquires as to "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?"

101.1 At page 5-69 BC Hydro identifies what it considers as the factors that lead to higher than average electricity use. Are these same factors applicable for areas without natural gas service and for low income customers?

101.2 Are there other factors driving higher than average electricity use that are unique to either areas without natural gas and/or low income customers?

102.0 Reference: Exhibit B-1, pages 5-72

102.1 There does not appear to be a section addressing the portion of Question 5 regarding "what options there are for additional residential DSM program, including low income programs, within the current regulatory environment" (per lines 9-11). Is it BC Hydro's view that there are no options for additional DSM programs?

76.1.1 If yes, what is the basis for this conclusion?

76.1.2 If no, please provide a response.

103.0 Reference: Exhibit B-1, page 5-74 to 5-78

103.1 What percentage of low income (LICO and under) houses in BC Hydro's service area does 85,000 represent (per page 5-74)?

103.2 Given the low income eligibility changes outlined on page 5-76, how many houses meeting the 2015 RDA definition of low income (LICO and under) have received ESKs since the program was launched in 2008?

103.3 How many of the approved ECAP applications were for houses with electric heat and, of these, how many received a high efficiency gas furnace?

103.4 Given the low income eligibility changes outlined on page 5-76, how many houses meeting the 2015 RDA definition of low income (LICO and under) have been approved for the ECAP and, of these, how many had electric heat and how many received a high-efficiency gas furnace?

104.0 Reference: Exhibit B-1, Section 5.6
BC Hydro Power Smart Home Loan Pilot Program Application

104.1 The BC Hydro Power Smart Home Loan Pilot Program was approved by the Commission on October 30, 2012 by Order G-162-12. Please advise

when it was discontinued. Since the program was only available to credit-worthy applicants, please confirm that it was not targeted to assist Low income customers. Has BC Hydro considered such an (interest free) program for its low income customers?

104.2 Did BC Hydro's evaluation of US jurisdictions identify any interest free programs for low income customers?

105.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

105.1 Please provide a copy of all Demand Side Management ("DSM"):

(a) Program planning documents prepared by or for BC Hydro since January 1, 2010 for any BC Hydro low income DSM programs; and
(b) Program evaluations prepared by or for BC Hydro since January 1, 2010 for any BC Hydro low income DSM programs.

106.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

106.1 Please provide all studies, reports, evaluations or other written documents of any nature within the custody or control of BC Hydro, prepared since January 2005 regarding the extent of the following DSM market conditions experienced by low income households in British Columbia:

(a) High initial capital costs of energy efficiency investments;
(b) Lack of access to capital for energy efficiency investments;
(c) High implicit discount rates/payback periods for energy efficiency investments;
(d) High proportion of low income renters;
(e) Split incentives between landlord and tenants relative to energy efficiency investments; and
(f) High mobility rate of low income renters.

107.0 Reference: Exhibit B-1, Section 5.6.2

107.1 Please provide the sections of BC Hydro's Conservation Potential Reviews, if any, that informed the two residential low income DSM program offerings.

107.2 What programs currently exist that may be able to assist low income BC Hydro ratepayers with paying their BC Hydro electricity bills?

108.0 Reference: Exhibit B-1, Section 5.6.2
Energy Savings Kits

108.1 Please explain the methodology used in evaluating the savings achieved by ESKs given the fact that each kit contains a number of components, some of which the customer may not be able to install.

108.2 Please confirm that until recently BC Hydro's website contained a section with the heading "Are you a low income BC Hydro customer? We can help you save $30 a year."

108.3 Please further confirm that by letter dated February 13, 2015 BC Hydro advised BCPIAC that "[T]he website headline 'We can help you save $30 a year' refers to the average electricity savings from ESKs. It is based on the blended average annual savings of the two current types of kits (standard and apartment). The cost of electricity assumed is $.0827/kWh based the residential exempt rate (Rate Schedule (RS) 1151 as of April 1, 2013)".

108.4 At p.5-75 of the Application, BC Hydro asserts that "The energy savings kits referred to above can help recipients save up to $100/year on utility bills." Please explain how the savings more than tripled, and provide a working spreadsheet that identifies the energy saved by individual components of the ESK, and the value of that energy, for both the $30 and the $100 annual savings calculation.

108.5 Please provide the cost of both types of ESKs to BC Hydro, together with the cost of third party delivery.

108.6 Please provide the annual cost of the ESK program for each year since 2008, by cost type, together with BC Hydro's estimate of energy saved.

108.7 Please provide BC Hydro's forecast program expenditures on ESKs for future years, together with its estimate of energy savings.

109.0 Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

109.1 Please confirm that Carillion Canada Inc. is the program contractor for ECAP. Are there any other contractors involved in the delivery of ECAP?

109.2 When was Carillion appointed, and what document, if any, did BC Hydro publish (such as a RFP) to elicit responses from interested parties? Please provide a copy of any such document.

109.3 How many assessments has Carillion performed since the inception of the program? Please provide an analysis by year and service area.

109.4 The ECAP application form states: "BC Hydro and FortisBC are not obligated to provide program support to any applicants including those who meet all program eligibility criteria. It is within BC Hydro's and FortisBC's sole discretion to accept or reject any applicant who meets all program eligibility criteria". Please provide all circumstances under which BC Hydro might reject an otherwise qualified application, and provide the numbers of such applications rejected by year, by service area and reason, for all years since ECAP started.

109.5 Please provide details of how the savings referred to on p.5-75 of the Application of $150 per year for basic measures and a fridge, and $300 per year for insulation upgrades were calculated. Please also clarify

whether the $300 referred to at p. 5-75 (line 4) is the total annual saving from all three sources or is simply referring to insulation savings.

109.6 Please provide the annual cost of the ECAP program for each year since 2008, by i) direct cost type (home evaluation, energy saving products, refrigerators and insulation); and ii) indirect cost type (administration, marketing, etc.). Please also provide BC Hydro's estimate of energy saved by program component.

109.7 Please provide BC Hydro's forecast program expenditures on the ECAP program for future years. Please also provide BC Hydro's estimate of energy savings by program component.

109.8 BC Hydro states that it conducted an evaluation of its ECAP program in 2011, a summary of which is included in the F2012 Demand Side Management Milestone Evaluation Summary Report to the BCUC. At line 22 of p. 13 of this report, BC Hydro refers to a study that analyzed the energy savings impact of ECAP and summarized the results. In order to evaluate the program, please provide the actual study, particularly sections that discuss the electricity use metrics of households in their pre and post experimental design with participant and non-participant groups.

109.9 Please confirm whether BC Hydro has conducted a new evaluation of ECAP, given that this evaluation is 4 years old and that the program has gone through significant changes over those 4 years.

109.10 How many ECAPs is BC Hydro capable of completing per year?

109.11 Does BC Hydro have a target number for ECAPs to complete per year? If so, what are those targets?

109.12 If BC Hydro has targets, are BC Hydro and its contractors able to process more than the target number of ECAP applications per year?

109.13 How many ECAP applications were turned down in 2015, 2014, and 2013, and for what reasons?

109.14 Is the primary goal of ECAP to provide BC Hydro with energy savings, or is the primary goal to significantly reduce bills for low income customers who are having difficulty paying their electricity bills?

109.15 Does BC Hydro do a meter reading before and after installation of ECAP measures in order to determine whether ECAP has resulted in energy and bill savings for residential customers?

109.16 How does BC Hydro verify income information without violating privacy laws when determining low income customers' eligibility for ECAP?

109.17 When BC Hydro collects customers' income data for determining eligibility for ECAP, does BC Hydro keep customer income data separate from the main customer service system?

110.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

110.1 For each month for the most recent twelve months available, disaggregated by heating and non-heating residential accounts, please provide:

(a) The average bill for residential accounts at existing rates provided in sufficient detail (including all input variables) to permit replication; and
(b) The same bill information using BC Hydro's rates as of April 1, 2016.

111.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

111.1 Please provide all empirical studies within BC Hydro's custody or control showing the relationship between income and electricity consumption, using data from:

(a) BC Hydro's customers;
(b) A Canadian electric utility, whether or not in British Columbia; and
(c) Any electric utility whether or not Canadian.

112.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

112.1 Please provide each customer demographic survey other than the Residential End Use Survey (REUS) that has been prepared for residential customers since January 2010. If no survey other than the REUS has been prepared since January 2010, please provide the most recent survey other than the REUS.

113.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

113.1 For BC Hydro's existing residential DSM programs, please provide:

(a) An explanation of how BC Hydro screens DSM projects;
(b) An identification of all potential DSM programs screened for its present DSM Plan;
(c) Any evaluation of the cost-effectiveness of its current DSM programs;
(d) A specification of the avoided cost estimates BC Hydro is using to screen DSM projects. Document the derivation of the avoided costs, including all workpapers and spreadsheets;
(e) The penetration rate estimated for each program together with the basis of that estimate;
(f) An estimate of the utility costs for each of BC Hydro's DSM programs;
(g) The basis of BC Hydro's forecast of energy and peak savings from each of its DSM programs;
(h) BC Hydro's total budget for DSM projects;
(i) An explanation of how BC Hydro determined how much to spend on DSM and what amount of savings to strive for;

(j) An identification of all DSM programs in which BC Hydro has been forced to shut off applications, or wait-list potential participants, due to budget constraints;
(k) An identification of all DSM programs in which BC Hydro could reach additional customers or fund additional cost-effective measures, if the program budgets were increased; and
(l) An identification and explanation of whether the DSM investment per customer is limited in any program. If so, describe those limits and explain why BC Hydro is not willing to make all cost-effective investments in DSM.

114.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

114.1 For the LICO x 130% customer base served by BC Hydro of customers directly paying their own energy bills, provide a distribution of the estimated number of such customers by the following ranges of LICO:

(a) 0 – 25% of LICO;
(b) 26 – 50% of LICO;
(c) 51 – 75% of LICO;
(d) 76 – 100% of LICO; and
(e) 101 – 130% of LICO.

115.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

115.1 For each band of LICO in the immediately preceding response, provide:

(a) The average income; and
(b) The median income.

116.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

116.1 Please provide by year for each year from 2012 to 2015, inclusive, disaggregated by heating and non-heating customers:

(a) The number of low income customers whose utility bills are being paid directly by a government agency to BC Hydro that would fall within the 30% of highest residential users; and
(b) The number of low income customers whose utility bills are being paid directly by a government agency to BC Hydro that would fall within the 50% of highest residential users.

117.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

117.1 Please provide all documents within BC Hydro's custody or control which, for the United States or Canada, identifies and/or otherwise discusses the

penetration of market-based energy efficiency measures in low income households.

118.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

118.1 Please provide an outline of any methodology or process that BC Hydro would find acceptable to dollarize and quantify the utility-related non-energy benefits (e.g., reduced bad debt, reduced arrearages, etc.) resulting from residential usage reduction generally and from low income usage reduction in particular.

119.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

119.1 For so-called "de facto electric heating" (defined as the situation in which a residential customer relies on portable electric heating as a primary source of heating even though the residence is configured to be heated primarily with gas service), please describe:

(a) Any DSM projects that have specifically addressed such de facto electric heating; and
(b) Any impediments to addressing such de facto electric heating within the context of BC Hydro's DSM programs.

120.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

120.1 Please identify and provide a description of, for the years January 2010 to 2015 inclusive, all affirmative efforts by BC Hydro (outside the low income programs described in Section 5.6.2 of the Application):

(a) To target DSM marketing to low income customers (and the results therefrom);
(b) To develop information regarding the low income DSM market (and the results therefrom);
(c) To identify low income market niches to serve with DSM if a broad-based low income program is not offered (and the results therefrom);
(d) To create piggyback programs to reach low income customers with DSM (and the results therefrom); and
(e) To develop partnerships with institutions serving low income customers to have those institutions deliver DSM (and the results therefrom).

121.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

121.1 Provide any analysis that BC Hydro has undertaken of its residential customer population since January 2005 in which it assesses the propositions that:

(a) The greater the energy consumption is in the pre-treatment period, the greater the potential for energy savings; and
(b) The greater the energy bill arrearage is in the pre-treatment period, the greater the reductions in energy consumption realized by DSM investments.

122.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

122.1 Provide all analyses that BC Hydro has undertaken since January 2005 of its residential population assessing the extent to which, if at all:

(a) Households with energy bill arrearages in the pre-treatment period reduce their arrearages following DSM services;
(b) The number of complete payments changes following DSM services; and
(c) The payment coverage ratio (i.e., payments as a percentage of billed revenue) changes following DSM services.

123.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

123.1 Please identify and provide any documents within BC Hydro's custody or control finding or otherwise discussing whether, and if so how and to what extent, utility-funded DSM programs tend to exclude low income customers without a low income set-aside.

124.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

124.1 Please identify all market barriers that impede or prevent a customer from installing cost-effective DSM measures in the absence of external assistance if the customer is:

(a) A residential customer irrespective of income; and
(b) A low income residential customer.

125.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

125.1 Please identify and provide any document within BC Hydro's custody or control discussing implicit discount rates (sometimes known as hurdle rates or internal rates of return) for residential DSM measures by income.

126.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

126.1 Please provide all documents within BC Hydro's custody or control discussing the extent to which, if at all, DSM measures delivered to low income customers result in the following associated with the customers:

(a) Reduced arrearages;

(b) Reduced bad debt expense;
(c) Reduced credit and collection activity;
(d) Improved timeliness of payments; and
(e) Improved completeness of payments.

127.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

127.1 Confirm or deny each of the following statements. If denied, provide a detailed explanation of the basis for the denial. All other things being equal:

(a) A reduced level of residential arrearages reduces BC Hydro's revenue requirement;
(b) A reduced level of residential bad debt reduces BC Hydro's revenue requirement;
(c) A reduced level of credit and collection activities reduces BC Hydro's revenue requirement;
(d) Improved timeliness of residential payments reduces BC Hydro's revenue requirement; and
(e) Improved completeness of residential payments reduces BC Hydro's revenue requirement.

128.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

128.1 Please explain each way in which, if at all, BC Hydro uses the following factors to target the delivery of residential DSM investments:

(a) Usage of the customer as a percentage of the residential mean or median usage;
(b) Level of arrearages of the customer;
(c) Length of residence of the customer at the housing unit to be treated; and
(d) Credit and collection or payment history of the customer.

129.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

129.1 Please describe all ways in which there is an integration of BC Hydro's utility-funded residential DSM programs with each of the following:

(a) Requests for deferred payment plans;
(b) Disconnections for nonpayment;
(c) Requests for crisis assistance; and
(d) Receipt of direct bill payment assistance from the Government.

130.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

130.1 Please identify and provide all documents prepared since January 2010 which identify or otherwise discuss:

(a) The existing institutional capacity to deliver low income DSM in British Columbia; and
(b) The potential institutional capacity to deliver low income DSM in British Columbia.

131.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

131.1 Please identify and provide a copy of all documents prepared by or for BC Hydro since January 2010 identifying and/or discussing:

(a) The technical potential for DSM savings for low income residential customers in BC Hydro's service territory;
(b) The economic potential for DSM savings for low income residential customers in BC Hydro's service territory;
(c) The percentage of technical potential for low income residential customers in BC Hydro's service territory yet to be realized; and
(d) The percentage of economic potential for low income residential customers in BC Hydro's service territory yet to be realized.

132.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

132.1 Please identify and provide a copy of all documents prepared by or for BC Hydro since January 2010 identifying and/or discussing:

(a) The technical potential for DSM savings for residential customers irrespective of income in BC Hydro's service territory;
(b) The economic potential for DSM savings for residential customers irrespective of income in BC Hydro's service territory;
(c) The percentage of technical potential for residential customers irrespective of income in BC Hydro's service territory yet to be realized; and
(d) The percentage of economic potential for residential customers irrespective of income in BC Hydro's service territory yet to be realized.

133.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

133.1 By residential DSM measure for each year from January 2010 to present, please provide the average installed cost. Separately provide, disaggregated by heating and non-heating customers where available, the per-household total average treatment cost of a residential unit by year during the same time period.

134.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

134.1 Please identify and provide a copy of all documents within BC Hydro's custody or control describing a low income DSM electric program in the United States or Canada that is a:

(a) Parallel program, defined to be a program in which a government agency runs two programs, one funded and designed by a government agency and a parallel one funded and designed by an electric utility.
(b) Supplemental program, defined to be a program in which the program relies on utility funding to support a government agency's ongoing program, with no changes in the program's design or operation; and
(c) Coupled program, in which a government agency and electric utility fund, design and implement the energy efficiency efforts.
(d) For each program identified in response to the question immediately above, please provide a brief description of all factors, if any, that would make such a program infeasible or uneconomic for BC Hydro.

135.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency – First Nations

135.1 Provide a breakdown of residential electricity consumption on First Nations reserve and treaty lands in BC by month, broken down by:

(a) Income, including LICO, LICO plus 30% and income above LICO plus 30%;
(b) Dwelling type;
(c) Heating type; and
(d) Household size.

135.2 Provide the number of residential customer accounts on First Nations reserve and treaty lands in BC, broken down by income, including LICO, LICO plus 30% and income above LICO plus 30%.

135.3 Describe the eligibility criteria and assessment process for ECAP for First Nations and whether the eligibility criteria and assessment process are different than applications from customers who are not First Nations.

135.4 How does BC Hydro address privacy issues related to income verification and eligibility assessment for ECAP and ESKs, for First Nations and non-First Nations applicants, if the process is different?

135.5 Is BC Hydro developing a First Nations Power Smart program?

110.6.1 If so, please describe the program and when BC Hydro plans to implement the program.

135.6 Does BC Hydro leverage dollars with Indigenous and Northern Affairs Canada to install ECAP where mould or other health and safety issues prevent installation of weatherization DSM measures on First Nations reserve and treaty lands?

135.7 How many households, annually, receive Advanced ECAP and how many receive Basic ECAP for the entire program?

135.8 How many First Nations households, annually, receive Advanced ECAP and how many receive Basic ECAP?

135.9 What fraction of households that receive ECAP do not receive any air sealing measures program wide?

135.10 What fraction of First Nations households that receive ECAP do not receive any air sealing measures?

136.0 Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

136.1 Are there any income support programs other than those listed in the definition of "low income household" in the Demand Side Measures Regulation at: http://www.bclaws.ca/civix/document/id/complete/statreg/326_2008 that BC Hydro currently accepts as proof of income for the purpose of qualifying for ECAP and ESKs?

136.2 If a BC Hydro customer receives social assistance through Indigenous Affairs and Northern Development Canada, would proof of this income be sufficient for such a customer to apply for ECAP and ESKs?

CHAPTER 6 – GENERAL SERVICE RATE DESIGN

137.0 Reference: Exhibit B-1, pages 6-8 to 6-12

137.1 Please clarify what is meant by customer-related costs (page 6-8) and indicate what the dollar value for customer-related costs is for the SGS class based on the F2016 COSS, providing the necessary cross-references to the F2016 COSS – per Appendix E.

137.2 Based on the F2016 SGS billing determinants (i.e., customers and energy) please provide the calculations demonstrating that the current F2016 basic charge recovers 35% of customer-related costs.

137.3 Does BC Hydro anticipate/foresee any issues arising from the fact the proposed basic charge for SGS (32 cents/day in F2017) will exceed the proposed basic charge for MGS customers (23.47 cents/day in F2017) – such that smaller customers will be seeing a higher basic charge?

138.0 Reference: Exhibit B-1, Appendix H-1A, page 55

138.1 Given that increasing the basic charge's recovery of customer related costs from 35% to 45% would require an increase of 28.6% (45/35) why is the escalation factor 1.36?

138.2 Please indicate how the 1.36 escalation factor for the SGS basic charge was determined.

139.0 Reference: Exhibit B-1, Appendix H-1A, page 55

139.1 Please provide a schedule similar to Table H-1A-43 (rows A-K) but for F2016 based on the approved rates. Please reconcile the revenues that result with those used in the COSS (Schedule 4.0) for the SGS class.

140.0 Reference: Exhibit B-1, Appendix H-1A, pages 53-59

Preamble: For purposes of modelling BC Hydro has calculated the "proposed SGS rates" for F2017-F2018 so as to be revenue neutral to revenue assuming the status quo rates for each year (page 53). BC Hydro proposes to implement the SGS changes April 1, 2017.

140.1 How will the increase in the basic charge for F2018 (over the F2017 basic charge) be determined, assuming the F2018 RRA increase is 3.5%?

140.2 How will the F2018 energy charge be determined? Will it be determined so as to maintain revenue neutrality as if the status quo rate design had been maintained for F2018?

140.3 How will revenue neutrality be defined for F2019? Will it be based on: a) revenues for F2019 assuming the status quo rate design had been maintained through to F2019 and applying the RRA increases or b) determining the F2019 revenues using the SGS rates approved for F2018 and escalating the results by the RRA for F2019?

141.0 Reference: Exhibit B-1, page 6-10

141.1 Assuming BC Hydro's rate increases for F2017 through F2019 match the rate caps set out on page 1-2, please provide a schedule that compares the SGS energy rates for F2018 and F2019 with the LRMC range for each of these years as set out in Table 2-6.

142.0 Reference: Exhibit B-1, page 6-14

142.1 Please explain why, for the lowest and highest percentiles, the difference between the last two columns is not 4% - the F2017 RRA increase.

143.0 Reference: Exhibit B-1, page 6-32

143.1 Assuming BC Hydro's rate increases for F2017 through F2019 match the rate caps set out on page 1-2, please provide a schedule that compares the MGS energy rates for F2018 and F2019 with the LRMC range for each of these years as set out in Table 2-6.

144.0 Reference: Exhibit B-1, pages 6-30 and 6-34

144.1 Please clarify what is meant by demand-related costs and indicate what the dollar value is for the MGS class based on the F2016 COSS, providing the necessary cross-references to the F2016 COSS – per Appendix E.

144.2 Based on the F2016 MGS billing determinants (i.e., customers, demand and energy) please provide the calculations demonstrating that the current F2016 demand charge recovers 15% of demand-related costs.

144.3 What percentage of the customer-related costs allocated to MGS are recovered though the basic charge? In responding, please indicate what the dollar value for customer-related costs is for the MGS, providing the necessary cross-references to the F2016 COSS – per Appendix E.

145.0 Reference: Exhibit B-1, pages 6-36 and 6-68

145.1 Please explain the difference between Figures 6-6 and 6-14. While the titles suggest both are showing the impacts of transitioning to BC Hydro's preferred MGS rate design in one year (6-6 net of the RRA and 6-14 including RRA), the differences between the values shown in the tables are more than the RRA increase for F2017.

146.0 Reference: Exhibit B-1, Appendix H-1A, page 37

146.1 Please provide a schedule similar to Table H-1A-31 (rows A-AF) but for F2016 based on the approved rates. Please reconcile the revenues that result with those used in the COSS (Schedule 4.0) for the MGS class.

147.0 Reference: Exhibit B-1, Appendix H-1A, page 43

147.1 Given that increasing the MGS demand charge's recovery of demand related costs from 15% to 35% would require an increase of 133% (35/15) why is the escalation factor 2.22 and not 2.33?

147.2 Please indicate how the 2.22 escalation factor for the MGS demand charge cost recovery was determined.

148.0 Reference: Exhibit B-1, Appendix H-1A, pages 43-48

Preamble: For purposes of modelling BC Hydro has calculated the "proposed rates" for F2017-F2018 so as to be revenue neutral to revenues assuming the status quo MGS rates for each year (page 43). BC Hydro proposes to implement the MGS changes April 1, 2017.

148.1 How will the flat demand charge for F2018 be determined, assuming the F2018 RRA increase is 3.5%?

148.2 How will the F2018 energy charge be determined? Will it be determined so as to maintain revenue neutrality as if the status quo rate design had been maintained for F2018?

148.3 How will revenue neutrality be defined for F2019? Will it be based on: a) revenues for F2019 assuming the status quo rate design had been maintained through to F2018 and applying the RRA increases or b) determining the F2019 revenues using the MGS rates approved for F2018 and escalating the results by the RRA for F2019?

149.0 Reference: Exhibit B-1, pages 6-49 to 6-50 and page 6-59

149.1 Assuming BC Hydro's rate increases for F2017 through F2019 match the rate caps set out on page 1-2, please provide a schedule that compares the LGS energy rates for F2017 to F2019 under BC Hydro's preferred

option (per page 6-59) with the LRMC range for each of these years as set out in Table 2-6.

149.2 At page 6-49 (lines 18-19) BC Hydro states that the improved changed (to 65% demand cost recovery from demand charges) "improves fairness and does so without a loss of efficiency". Please explain why there is no loss in efficiency when moving from 50% to 65% demand cost recovery via the demand charge decreases the energy rate (per Table 6-18) and moves it further away from the LRMC range.

150.0 Reference: Exhibit B-1, pages 6-49 and 6-58

150.1 Based on the F2016 LGS billing determinants (i.e., customers, demand and energy) please provide the calculations demonstrating that the current F2016 demand charges recover 50% of demand-related costs. In doing so please indicate (with reference to the F2016 COSS – Appendix E) what the demand-related costs allocated to LGS are.

150.2 What percentage of the customer-related costs allocated to LGS are recovered though the basic charge? In responding, please indicate what the dollar value for customer-related costs is for the LGS class, providing the necessary cross-references to the F2016 COSS – per Appendix E.

151.0 Reference: Exhibit B-1, page 6-58

151.1 Page 6-58 indicates that for RS 1823 customers (i.e., Transmission Service customers), the demand charge recovers 65% of demand costs. How are demand cost for RS 1823 customers defined for purposes of this calculation? In particular, given there is no basic charge for RS1823 customers, does the definition include the customer-related costs allocated to Transmission Service customers?

151.2 Based on the F2016 billing determinants (i.e., customers, demand and energy) for Transmission service customers, please provide the calculations demonstrating that the current F2016 demand charge recovers 65% of demand-related costs. In doing so please indicate (with reference to the F2016 COSS – Appendix E) what the demand-related costs allocated to Transmission service customers are.

151.3 If customer-related costs are not include in the definition of "demand costs" used for purposes of calculating the 65%, please recalculate (similar to the response to part (2)) the percentage with customer-related costs included.

152.0 Reference: Exhibit B-1, Appendix H-1A, pages 19-22

152.1 Please provide a schedule similar to Table H-1A-19 (rows A-AE) but for F2016 based on the approved F2016 rates. Please reconcile the revenues that result with those used in the COSS (Schedule 4.0) for the LGS class.

153.0 Reference: Exhibit B-1, Appendix H-1A, page 26

153.1 Please indicate how the 1.3 escalation factor for the LGS demand charge cost recovery was determined.

154.0 Reference: Exhibit B-1, Appendix H-1A, pages 26-30

Preamble: For purposes of modelling BC Hydro has calculated the "proposed rates" for F2017-F2019 so as to be revenue neutral to revenues assuming the status quo LGS rates for each year (page 26). BC Hydro proposes to implement the LGS changes April 1, 2017.

154.1 How will the flat demand charge for F2018 be determined, assuming the F2018 RRA increase is 3.5%?

154.2 How will the F2018 energy charge be determined? Will it be determined so as to maintain revenue neutrality as if the status quo rate design had been maintained for F2018?

154.3 How will revenue neutrality be defined for F2019? Will it be based on: a) revenues for F2019 assuming the status quo rate design had been maintained through to F2018 and applying the RRA increases or b) determining the F2019 revenues using the LGS rates approved for F2018 and escalating the results by the RRA for F2019?

155.0 Reference: Exhibit B-1, pages 6-65, 6-67 and 6-69

155.1 Please confirm that, based on Figure 6-12, the highest LGS bill impact shown (excluding RRA) is 4%. If not, what is the value?

155.2 Based on actual customer billing profiles: a) what is the maximum impact an LGS customer would see (including the F2018 RRA of 3.5%) and b) how many LGS customers will see a bill impact in excess of 10% (including the F2018 RRA of 3.5%)?

155.3 Does BC Hydro agree that one of the factors affecting customer acceptance is bill impacts?

155.4 Please explain the difference between Figures 6-12 and 6-16. While the titles suggest both are showing the impacts of transitioning to BC Hydro's preferred LGS rate design in one year (6-12 net of the RRA and 6-16 including RRA), the differences between the values shown in the tables are more than the RRA increase for F2017.

156.0 Reference: Exhibit B-1, pages 6-70 to 6-71

156.1 Given the currently existing "new" LGS and MGS customers and assuming an addition of new customers for November 15, 2015 through March 31, 2016 matching that experienced in the period November 15, 2014 through March 31, 2015, what would be the impact on BC Hydro's F2016 net income of the requested change in the new account rule for LGS and MGS customers effective January 1, 2016?

157.0 Reference: Exhibit B-1 page 6-74

157.1 Does BC Hydro plan/construct either transmission or distribution facilities to provide service under RS 1253?

158.1.1 If yes, who pays for these facilities?

158.1.2 If no, is RS 1253 service denied when there are insufficient existing transmission and/or distribution facilities to deliver the requested service?

157.2 How are RS1253 loads and revenues treated in the COSS?

CHAPTER 7 – TRANSMISSION SERVICE RATE DESIGN

158.0 Reference: Exhibit B-1, page 7-7

158.1 Does the BCUC have the jurisdiction to determine what the appropriate LRMC value is for purposes of setting the Tier 2 rate?

158.2 Does the BCUC have the jurisdiction to alter the percentage of demand-related costs that are recovered through the demand charge?

159.0 Reference: Exhibit B-1, pages 7-8 to 7-9

159.1 The Application states that a choice between revenue neutrality definitions must be made for F2017 but is not necessary for F2018 or F2019. Will the choice of revenue neutrality definition for F2017 affect the level of revenue that will be recovered from Transmission Service customers in F2017 – for a given level of RRA increase?

160.1.1 If not, please explain why and demonstrate with supporting calculations.

159.2 If yes, does this mean that the definition of revenue neutrality used for Transmission Service customers could affect the level of the overall RRA increase required in F2017 (assuming the level of RRA increase is established in order to provide a certain level of revenue requirement in F2017)?

160.2.1 If not, please explain why and demonstrate with supporting calculations.

159.3 The Application states that a choice between revenue neutrality definitions must be made for F2017 but is not necessary for F2018 or F2019. Will the choice of revenue neutrality definitions for F2017 affect the level of revenue to be that will be recovered from Transmission Service customers in F2018 and F2019 – for a given level of RRA increase?

160.3.1 If not, please explain why and demonstrate with supporting calculations.

159.4 If yes, does this mean that the definition of revenue neutrality used for Transmission Service customers in F2017 could affect the level of the overall RRA increase required in each of F2018 and F2019 (assuming the

RRA increase is established in order to provide certain levels of revenue requirements in F2018 and F2019)?

160.4.1 If not, please explain why and demonstrate with supporting calculations.

159.5 Please confirm that the conclusion (page 7-9, lines 2-5) that the "RRA increases thereafter will result in RS 1823 pricing that in F2019 and F2019 satisfies all the requirements of Direction No. 7" is based on the assumption that the RRA increases will be equal to or exceed inflation.

160.0 Reference: Exhibit B-1, pages 7-9 to 7-10; pages 7-12 to 7-13 and Appendix H-1A

160.1 Please provide the forecast Transmission Service billing quantities (e.g. demand, Tier 1 energy, Tier 2 energy) for F2016 as used in the COSS.

160.2 Please provide a schedule setting out the calculation of the F2016 revenue for the transmission service class as presented in Appendix E, COSS Tab 4.0 ($889.32 M).

160.3 Please provide the derivation of the F2017, F2018 and F2019 revenues at F2016 Transmission Service rates and what the resulting revenue targets would be for F2017-F2020 using the RRA increases per Appendix H-1A (page 2).

160.4 Please provide the derivation of the F2017 revenues to be recovered from Transmission Service customers using the bill neutrality definition of revenue neutrality and an F2017 RRA increase of 4% under each of the three Options.

160.5 Please provide (using schedules similar to those employed for the MGS and LGS classes in Appendix H-1A), the derivation of the F2017-F2020 rates presented for each of the Options in Table 7-3.

160.6 Please provide the derivation of the F2017 revenues to be recovered from Transmission Service customers using the forecast revenue neutral definition of revenue neutrality and an F2017 RRA increase of 4%.

160.7 Please provide a schedule similar to Table 7-3 that sets out the Transmission service rates and resulting revenues for each of the options for F2017-F2020 assuming a forecast revenue neutral definition of revenue neutrality is used for F2017.

161.7.1 As part of the response, please provide (using schedules similar to those employed for the MGS and LGS classes in Appendix H-1A), the derivation of the F2017-F2020 rates presented for each of the Options using the forecast revenue neutral definition of revenue neutrality.

161.0 Reference: Exhibit B-1, page 7-13

161.1 Please provide the calculations supporting the impacts reported at lines 15-19, showing the calculation of the revenues using the different approaches and the resulting differences as reported.

162.0 Reference: Exhibit B-1, page 7-14

162.1 Given that the use of the bill neutrality definition of revenue neutrality for the Transmission Service alters the F2017 revenues, couldn't this approach be viewed as implicitly rebalancing the revenue allocation between the customer classes?

163.1.1 If not, why not?

163.0 Reference: Exhibit B-1, page 7-21

163.1 Why is the difference in Mid-C monthly prices used to shape the Tier 2 rate for each season when the Tier 2 rates itself is based on LRMC and not short-term market prices?

164.0 Reference: Exhibit B-1, pages 7-22 to 7-23

164.1 Is BC Hydro proposing any restrictions as to how frequently it can alter the RS 1852 definition of HLH or how much notice customers will be given of a planned change?

165.0 Reference: Exhibit B-1. pages 7-25 to 7-26

165.1 Please explain more fully why an RTP option would result in non-firm service for incremental demand above the CBL.

166.0 Reference: Exhibit B-1, pages 7-27 to 7-29

166.1 Given the potential variation in spring water flows, what is the likelihood that there will be spills in F2017-F2020, assuming no freshet rate is offered?

166.2 With respect to Figure 7-2, given the export capability of BC Hydro's current interties, is the system physically able to "export" the surplus shown as it occurs or would there still be "surplus"?

166.3 With respect to Figure 7-2, based on anticipated reservoir levels at the start of F2017, would BC Hydro be able to "store" the surplus identified in part (2) and, if not, what would be the anticipated amount spilled?

166.4 If practical please re-do Figure 7-2 assuming water flows at a P90 level for F2017 (i.e., water flows would only be higher 10% of the time) and provide responses to parts (2) and (3) assuming these conditions.

167.0 Reference: Exhibit B-1, pages 7-29 to 7-32

Preamble: At page 7-30 the Application states:

> "At Workshop 10, BC Hydro pointed out that average August prices over the 2010 to 2014 period are noticeably higher than

May to July prices and that differentials between HLH and LLH periods have generally averaged about $15/MWh during the freshet compared to about $5/MWh during other times of the year. This price spread indicates there may be greater incentive for customers to shift load from HLH to LLH during the freshet period relative to other times of the year (provided they have the ability to do so)."

167.1 Which "customers" is BC Hydro referring to given that the current RS 1823 provides no incentive from customers to shift from HLH to LLH?

167.2 Is Figure 7-4 calculated based solely on Mid-C prices or were the prices adjusted to incorporate the wheeling fee and price floor as proposed at page 7-37.

168.2.1 If the wheeling fee and price floor were not used in the determination of Figure 7-4, please provide a revised figure after these two elements have also been taken into account.

168.0 Reference: Exhibit B-1, pages 7-32 to 7-34

168.1 Please describe what BC Hydro's "fairness concerns" are regarding offering (indirectly) residential customers of UBC, SFU and New Westminster market priced energy (per page 7-33).

168.2 With respect to billing, will there be any interest accumulated on the bill in recognition of the fact that RS 1892 usage in May through July will billed retroactively in August?

169.0 Reference: Exhibit B-1, page 7-35

169.1 Is it BC Hydro's expectation that the maximum kW purchased under RS 1823 and RS 1892 will be less than the customer's (existing) contract demand?

170.1.1 If it does exceed the contract demand for any of the months May through July, what (if any) additional charges will apply?

169.2 Will a customer be permitted to temporarily increase its contract demand for the duration of the RS 1892 pilot?

169.3 If the Net to Gross ratio is less than 100%, will there be any additional demand charges for load taken in excess of the Reference Demand?

170.3.1 If not, why not?

170.3.2 If yes, how will they be determined?

170.0 Reference: Exhibit B-1, page 7-38

170.1 Has BC Hydro attempted to quantify any of the risks noted a lines 8-21?

171.1.1 If yes, what are the potential dollars consequences and the likelihood of them occurring?

170.2 The possibility that customers will shift load from non-freshet months of the year into the freshet months was not identified as a risk, even if low. Why not?

170.3 The possibility of customers shifting load from one plant another was not identified as a risk? Does BC Hydro consider this to be a risk?

171.3.1 If no, why not?

109.3 How was the $3/MWh value for the proxy wheeling fee established?

171.0 Reference: Exhibit B-1, page 7-42

171.1 Please clarify what is meant by "Energy is provided on an 'as available' basis at Mid-C market prices".

171.2 The text at lines 7-8 suggests that BC Hydro views shifting RS 1823 load in non-freshet months to increase RS 1892 load during the freshet months is a valid use of the freshet rate. Please confirm whether or not this is the case.

172.2.1 If yes, please fully explain why and demonstrate that such shifting will be of benefit to BC Hydro and non-participating customers.

172.0 Reference: Exhibit B-1, page 7-44

172.1 Can BC Hydro terminate the supply of RS 1853 if it does not have sufficient generation or transmission capacity or is the special condition under the tariff limited to generation capacity?

172.2 The RS 1853 tariff provisions state that: "Prior to taking Electricity under this Schedule, the Customer <u>may</u> be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of energy under this Schedule" (emphasis added).

173.2.1 Under what circumstances would prior BC Hydro approval not be required?

173.2.2 If prior approval is not required, is the customer required to advise BC Hydro (after the fact) that it is taking service under the rate and, if so, how soon after starting to take service must notice be given?

173.0 Reference: Exhibit B-1, page 45

173.1 Can BC Hydro terminate the supply of RS 1880 if it does not have sufficient generation or transmission capacity or is the special condition under the tariff limited to generation capacity?

<u>CHAPTER 8 – ELECTRIC TARIFF TERMS AND CONDITIONS</u>

174.0 Reference: Exhibit B-1, pages 8-6 to 8-7 and Appendix G1-B, pages 1 to 6

174.1 For each of the Minimum Connection charges please provide a schedule that contrasts the following with the values used in the 2007 RDA for setting the comparable charge: a) Labour, including hours required and hourly rate, b) Material Costs and Material Handling Charges, and c) Vehicle Costs.

174.2 With respect to the First Subsequent Meter charge, under what circumstances would this meter be required and who would pay for the cost of the actual meter?

174.3 With respect to the Additional Meter Installations charge, under what circumstances would additional meters be required and who would pay for the cost of the actual meter?

174.4 Please provide the supporting details (i.e., labour and vehicle time and costs) to support the manual reconnection performed on overtime charge of $280 per meter.

175.4.1 If there is more than one meter at the site requiring reconnection, why would each one be subject to the same $280 charge?

175.0 Reference: Exhibit B-1, pages 8-9 to 8-11

175.1 Under what circumstances is a manual reconnection deemed to have been performed on overtime?

175.2 If a customer requests a reconnection outside of normal working hours is the customer advised, in advance, whether the reconnection will be subject to a “manual reconnection performed on overtime” charge or not before the work is performed?

175.3 Under what circumstances is the customer deemed to have “refused access” (per page 8-11). For example, if the customer is not at home and BC Hydro is unable to access the meter, is the customer deemed to have refused access?

176.0 Reference: Exhibit B-1, page 8-7 and Appendix G1-B, page 10

176.1 Please describe the circumstances under which a “Service Connection Call-Back Charge” would be levied.

176.2 Why is the number of PLTs required for this work 1.33 as opposed to 1.0?

176.3 Please explain why there is variation in travel time for the various charges that are costed out in Appendix G1-B, ranging from 0.6 hours to 1.0 hours.

177.0 Reference: Exhibit B-1, Section 8.3.3
Late payment charge

177.1 Please confirm that the purpose of BC Hydro’s late payment charge is to incentivize customers to pay their bills on time.

207.1.1 If not confirmed, please describe the purpose of the late payment charge.

178.0 Reference: Exhibit B-1, Section 8.3.3
Late payment charge

178.1 Assume for purposes of this Information Request that a residential bill is rendered on Day 1. Assume further the bill remains unpaid. Provide the timeline of each collection step until the bill is final-billed for nonpayment. Identify the Day on which each step of the collection process can be expected to occur. If this timeline varies depending on the account holder's credit history, please provide each possible timeline. If this question is fully answered by at Appendix C-3B, Attachment 1 (p. 2176 of the PDF file), please advise.

179.0 Reference: Exhibit B-1, Section 8.3.3
Late payment charge

179.1 For the most recent 12-month period available, by month for residential accounts, please provide:

(a) What percentage of bills were paid by the due date of the bill.
(b) What percentage of bills were paid by the time the next month's bill is rendered.
(c) What percentage of those bills were paid by the time the second subsequent bill is rendered.
(d) What percentage of those bills were paid by the time the third subsequent bill is rendered.

180.0 Reference: Exhibit B-1, Section 8.3.3
Late payment charge

180.1 Please provide the dollars of residential late fee revenue collected by month for each month January 2012 to present.

180.2 Please provide the number of residential accounts paying a late charge by month for each month January 2012 to present.

181.0 Reference: Exhibit B-1, Section 8.3.3
Late payment charge

181.1 Please provide a single copy of all studies within BC Hydro's custody or control documenting the effectiveness of a late payment charge as an incentive to pay for:

(a) Residential utility customers.
(b) Low-income residential customers.

182.0 Reference: Exhibit B-1, Section 8.3.3
Late payment charge

182.1 Please provide by month for each month January 2012 to present, a distribution of the number of residential accounts in arrears by the size of arrears by the following bands: (1) $0 - $100; (2) $101 - $200; (3) $201 -

$300; (4) $301 - $500; (5) $501 - $750; (6) $751 - $1,000; (7) $1,001 - $2,000; and (8) $2,001 and above. If these bands are not available, please provide the numbers of accounts by which bands are available.

183.0 Reference: Exhibit B-1, Section 8.3.3
Late payment charge

183.1 Please provide the total costs of the Accenture Business Service (ABSBC) credit and call center included in revenue requirement for this rate case.

183.2 Separately provide the total ABSBC costs for each of the past three fiscal years.

183.3 For each total cost provided in response to "a", provide the allocation of those total costs to credit and collection.

183.4 For each allocation provided immediately above, provide both a description of the basis upon which the allocation was made and the data on which the allocation was made.

184.0 Reference: Exhibit B-1, Section 8.3.3
Late payment charge

184.1 Please provide, in a live Excel spreadsheet, in sufficient detail to allow replication, with all formulas intact, the derivation of the weighted average interest cost cited in BC Hydro's application using a weighted average cost of debt of 4.28%.

185.0 Reference: Exhibit B-1, Section 8.3.3
Late payment charge

185.1 Please provide by month since January 2012:

(a) The total number of calls received for BC Hydro by ABSBC credit and call center, disaggregated by the reason for the call;
(b) All studies, evaluations, reports or other written documents of any nature that assess or otherwise discuss an allocation of staff time in hours, days, or increments of hours and/or days by the ABSBC credit and call center disaggregated by the reason for the call;
(c) All studies, evaluations, reports or other written documents of any nature that assess or otherwise discuss the degree to which in-bound calls to the ABSBC credit and call center result in first-call resolution of the reason for the call;
(d) All studies, evaluations, reports or other written documents of any nature that assess or otherwise discuss the allocation of ABSBC costs, disaggregated by the reason for the call, between in-bound calls and out-bound calls; and
(e) All studies, evaluations, reports or other written documents of any nature that assess or otherwise discuss the allocation of ABSBC costs disaggregated by calls and personal contacts.

186.0 Reference: Exhibit B-1, Section 8.3.3
Late payment charge

186.1 In a typical month, with Day 1 being the day a bill is issued, please provide the percentage of residential accounts making payments by day through Day 30. If reporting of such data is only by a time period other than a day (e.g., weekly), provide by the reporting by that time period.

187.0 Reference: Exhibit B-1, Section 8.3.3
Late payment charge

187.1 Please provide a list of all circumstances other than full payment of a bill that stop:

(a) The collection process for BC Hydro residential customers (e.g., entering into a deferred payment plan, filing a medical certificate, the winter shutoff moratorium); and
(b) The imposition of a late payment charge on a residential account in arrears.

188.0 Reference: Exhibit B-1, Section 8.3

188.1 Please provide a detailed explanation of the order in which customer payments are applied against various components of an account balance. Indicate, for example, whether late payment charges are paid before usage charges, whether unpaid balances are paid in the order in which they were incurred, etc.

189.0 Reference: Exhibit B-1, Section 8.4
Security deposits

189.1 For each month starting from January 2012 to present, please provide:

(a) The number of residential accounts for whom cash security deposits were held;
(b) The dollar amounts of cash security deposits held for residential customers;
(c) The number of cash security deposits applied to final bills;
(d) The percentage of final bills paid by security deposits applied to said bills; and
(e) The dollars of cash security deposits applied to final bills.

190.0 Reference: Exhibit B-1, pages 8-24 to 8-28

190.1 With respect to security deposits, given the proposed “up to” wording change (per page 8-21), why would a tariff amendment be necessary if income becomes a criterion (per page 8-24)?

178.1.1 What types of factors does BC Hydro view as being possible to take into account in applying the “up to” qualification without a tariff amendment?

178.1.2 Given these factors, how will BC Hydro determine the level of security deposit required in any particular circumstance?

190.2 Does BC Hydro return security deposits to customers after they have established a “good payment history” (per page 8-19)?

178.2.1 If so, how long a period of “good payment” is required?

190.3 With respect to Billing Errors, what is the standard extended repayment period employed by BC Hydro?

190.4 With respect to the Disconnection Grace Period, what are the specific process changes that BC Hydro is looking to implement?

190.5 With respect to Arrears Payment Arrangements, is the repayment period common for all with similar sizes of outstanding balances or is there currently some flexibility to the repayment period?

190.6 What is BC Hydro’s current policy/practice with respect to Winter Disconnects?

191.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

191.1 Disaggregated by heating and non-heating residential customers, please provide by month for each month January 2012 to the present:

(a) The average bill for all residential accounts;
(b) The average arrears of residential accounts in arrears;
(c) The average bill of residential accounts in arrears;
(d) The total dollars of residential arrears
(e) The percentage of residential dollars constituting arrears;
(f) The percentage of billed residential accounts having arrears; and
(g) The average arrears of all residential accounts disconnected for nonpayment in that month.

192.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

192.1 Please provide the final low income terms and conditions “business case” analysis prepared by the BC Hydro in 2015.

193.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

193.1 Please provide a copy of all reports, evaluations, memos, analyses or other written documents of any nature containing BC Hydro methodology, procedure or process designed to systematically review, study or assess BC Hydro residential billing and/or payment records in an effort to:

(a) Characterize patterns of nonpayment;
(b) Identify the characteristics of nonpayers;
(c) Identify predictors of nonpayment;
(d) Identify strategies to reduce nonpayment;
(e) Identify early indicators of nonpayment.

194.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

194.1 Disaggregated by heating and non-heating customers, please provide the number of residential accounts by month for each month January 2012 to present.

195.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

195.1 Please identify all BC Hydro accounts that include expenses for the following residential collection activities:

(a) Late payment notices;
(b) Notices of disconnection for nonpayment.
(c) Disconnections for nonpayment.
(d) Field collections not involving disconnection for nonpayment.

Separate these expenses by sub-accounts if available.

196.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

196.1 For Fiscal Years 2013 to present, please provide period-end totals of collection expenses booked to each account and sub-account identified in the Information Request immediately above.

197.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

197.1 For Fiscal Years 2013 to present, please provide a copy of all BC Hydro budget documents specifically identifying collection activities as a separately stated line-item.

(a) Provide those budget documents indicating the budgeted expenditures year-to-date;
(b) Provide those budget documents, if different, of actual expenditures year-to-date.

198.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

198.1 Please provide a copy of all written documents that explain, assess or otherwise discuss the criteria BC Hydro uses to assess on an ongoing basis the effectiveness of its current credit and collection activities.

198.2 Separately provide any written assessment, evaluation, report or other written document of any nature prepared since January 1, 2010 which discusses the effectiveness of BC Hydro's current credit and collection activities.

199.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

199.1 Please provide all written studies currently within BC Hydro's custody or control, whether or not prepared by or for BC Hydro, that explicitly assess the extent to which the following activities reduce residential bad debt:

(a) Cash security deposits;
(b) Deferred payment agreements;
(c) Disconnections for nonpayment;
(d) Field collections;
(e) Call center collection calls;
(f) Budget billing plans;
(g) Late payment charges.

200.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

200.1 Please provide all written studies currently within BC Hydro's custody or control, whether or not prepared by or for BC Hydro, that explicitly assess the extent to which the following activities reduce residential arrears:

(a) Cash security deposits;
(b) Deferred payment agreements;
(c) Disconnections for nonpayment;
(d) Field collections;
(e) Call center collection calls;
(f) Budget billing plans;
(g) Late payment charges.

201.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

201.1 Please provide any documents, analyses or reports in BC Hydro's custody or control, whether or not prepared by or for BC Hydro, that indicates, evaluates or otherwise discusses the amount which residential arrears must reach in order for BC Hydro to cost-effectively disconnect service due to the arrearage.

202.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

202.1 Please indicate whether residential late payment charges are compounded. In other words, please indicate whether residential late fees are imposed on unpaid late fees.

203.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

203.1 Please provide a copy of a typical residential notice of disconnection for nonpayment printed in each of the following months:

(a) November 2014
(b) January 2015
(c) April 2015
(d) August 2015

If more than one type of residential disconnection notice is issued, provide a copy of each.

204.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

204.1 By month for each month January 2012 to present inclusive, please provide:

(a) The number of new deferred payment arrangements entered into;
(b) The average downpayment (in dollars) of deferred payment arrangements entered into disaggregated by the arrearages at the time the deferred payment arrangement is sought;
(c) The average term (in months) of deferred payment arrangements entered into;
(d) The average dollar amount of arrears made subject to the deferred payment arrangement disaggregated by their term (in months) of the payment arrangement agreement;
(e) The average monthly installment of deferred payment arrangements disaggregated by their term (in months) of the payment arrangement agreement;
(f) The distribution of new deferred payment arrangements by their term (in months);
(g) The number of defaulted deferred payment arrangements;
(h) The number of defaulted deferred payment arrangements disaggregated by their term (in months) of the payment arrangement agreement;
(i) The number of completed (or “successful”) deferred payment arrangements disaggregated by their term (in months) of the payment arrangement agreement.

205.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

205.1 Please list all the programs and initiatives BC Hydro has undertaken since January 2010 to reduce the number of residential disconnections for nonpayment; if available, the metrics BC Hydro uses to determine if these programs are successful; and the results of any application of evaluation using those metrics.

206.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

206.1 Please list all the programs and initiatives BC Hydro has undertaken since January 2010 to reduce the number of delinquent residential accounts; if available, the metrics BC Hydro uses to determine if these programs are successful; and the results of any application of evaluation using those metrics.

207.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

207.1 Of the residential accounts receiving a notice of an impending disconnection for nonpayment, for each month January 2012 to present inclusive, please provide:

(a) The total number of accounts that did not have their service disconnected by the date specified in the disconnect notice;
(b) The total number of accounts that did not have their service disconnected prior to the next bill received after receiving the notice of disconnection;
(c) The total number of accounts that did not have their service disconnected for nonpayment after receiving a disconnect notice for nonpayment that voluntarily terminated their accounts;
(d) The total number of accounts that did not have their service disconnected because the customer paid their bills in full prior to their scheduled disconnection;
(e) The total number of accounts that did not have their service disconnected because the customer paid their bills less than in full but sufficient to avoid their scheduled disconnection;
(f) The total number of accounts that did not have their service disconnected even though they retained an arrears that was sufficient large (or sufficiently old) to trigger a disconnection); and
(g) The total number of accounts on which account no payments were made prior to the issuance of the next bill after issuance of the disconnect notice.

208.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

208.1 Please provide each customer segmentation study that has been prepared for BC Hydro of its residential customers since January 2010. If no such study has been prepared since January 2010, please provide the most recent study.

209.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

209.1 Please provide a copy of all written documents, of any nature, including tariffs, staff training manuals and staff "procedures" manuals, that describe and explain the circumstances under which:

(a) Termination of service *is* appropriate as well as the circumstances under which termination of service is *not* appropriate;
(b) It is appropriate and/or inappropriate to negotiate deferred payment plans
(c) A cash security deposit is required of: (i) a new customer; and (ii) an existing customer;
(d) It is appropriate and/or inappropriate to place residential customers on a levelized monthly (or budget) billing plan;
(e) BC Hydro will turn a residential account over to a third party collection agency for collection.

210.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

210.1 Please provide a copy of all reports, evaluations, memos, analyses or other written documents of any nature containing an articulation of performance indicators on which empirical data has been collected for BC Hydro with respect to:

(a) Debt prevention;
(b) Debt management;
(c) The treatment of vulnerable residential customers;
(d) Customer satisfaction.

211.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

211.1 Please provide a copy of all reports, evaluations, memos, analyses or other written documents of any nature prepared since January 2010 establishing performance indicator targets to be met within the next year after publication of the performance targets; within the next two years after publication of the performance targets; or within the next three years after publication of the performance targets, with respect to:

(a) Debt prevention;
(b) Debt management;
(c) The treatment of vulnerable customers;
(d) Customer satisfaction.

212.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

212.1 Please provide a copy of all reports, evaluations, memos, analyses or other written documents of any nature prepared since January 2010 assessing, evaluating or otherwise discussing whether the one-, two- and/or three-year performance indicator targets identified in the response to the immediately preceding question were fulfilled, satisfied or otherwise achieved.

213.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

213.1 Please provide by month for each month January 2012 to present:

(a) The number of unpaid residential accounts turned over to third-party collection agencies for collection;
(b) The dollars of unpaid residential accounts turned over to third-party collection agencies for collection;
(c) The dollars of unpaid residential accounts actually collected by third party collection agencies;
(d) The percentage of unpaid residential dollars actually collected by third party collection agencies;
(e) The dollars of fees paid to third party collection agencies for the collection of unpaid residential accounts; and
(f) The percentage of collections / billings charged by third party collection agencies disaggregated by : (1) whether unpaid bills assigned to the agency are actually collected; or (2) whether unpaid

bills assigned to the agency are not collected.

214.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

214.1 Please provide a copy of:

(a) The results of any call center satisfaction transactional research survey (e.g., "point-of-contact" survey, "moment of truth" survey) performed within the immediately preceding 36 months.
(b) A copy of the survey;
(c) A description of the survey methodology, including but not limited to the sample size, how the targets are selected, and the like.
(d) An explanation of how BC Hydro uses the results of this survey to improve service to its customers.

215.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

215.1 Please provide each study benchmarking BC Hydro's customer satisfaction, revenue collection, revenue protection, or other customer service activities against national, regional or size-based peer electric companies.

216.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

216.1 Please provide a list of all internal policy constraints placed on the disconnection of service for nonpayment. Such constraints might include, but not be limited to, a minimum dollar level of arrears that must be reached before a disconnection for nonpayment is performed; a minimum age of arrears that must be reached before a disconnection for nonpayment is performed; and other similar policies. For each item on the list, provide the specific constraint. For example, provide the dollar amount above which arrears must be for the account to be disconnected. Provide the age an arrears must be before it is disconnected.

217.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

217.1 Please provide by month for each month January 2012 to present:

(a) The interest rate paid on credit balances for residential accounts using Equalized Billing; and
(b) The interest rate charged on account balances for residential accounts using Equalized Billing.

218.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

218.1 For each month, or other time period as is reasonably available, please provide the number of cash security deposits requested for new customers disaggregated by whether the basis for the security deposit request was: (1) a poor payment history with a public utility; (2) a credit

score from Equifax; and (3) a credit score from a credit reporting agency other than Equifax.

219.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

219.1 Please indicate by month, or other time period as is reasonably available, the percentage of Equifax credit scores upon which BC Hydro relied to determine the need to request a cash security deposit which scores were based exclusively on utility bill payment history.

220.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

220.1 For each fiscal year 2012 to current inclusive, separated by residential and non-residential accounts, please provide:

(a) The total budgeted collection costs associated with handling delinquent accounts, excluding administrative and overhead expenses; and
(b) The total actual collection costs associated with handling delinquent accounts, excluding administrative and overhead expenses.

221.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

221.1 Please provide a comprehensive list of the options that a residential customer has to pay their BC Hydro bill. The list of payment options should include, if available, payment through a third party authorized community pay station (or payment center). In addition, for each option:

(a) For each month January 2012 to present, please provide the number of payments received through each option;
(b) Indicate the fee, if any, which is imposed to utilize that option;
(c) Provide a detailed cost justification for that fee; and
(d) For each year 2012 to present, please provide the dollars generated by such fee.

222.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

222.1 For each month January 2014 to present, inclusive, provide the total billing by month and the rate at which the billings in each month are converted into receipts, in substantially the following form:

Month	$s of Billed Revenue	Collected Receipts in Dollars													
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	After Dec	Total
JAN															
FEB		---													
MAR		---	---												
APR		---	---	---											
MAY		---	---	---	---										
JUN		---	---	---	---	---									
JUL		---	---	---	---	---	---								
AUG		---	---	---	---	---	---	---							
SEP		---	---	---	---	---	---	---	---						

OCT		---	---	---	---	---	---	---	---	---					
NOV		---	---	---	---	---	---	---	---	---	---				
DEC		---	---	---	---	---	---	---	---	---	---	---			
Etc.															

223.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

223.1 Please provide a copy of all written documents, of any nature, including tariffs, staff training manuals, and staff “procedures" manuals, that set forth the credit scoring techniques BC Hydro uses for residential customers. Specifically, this request is for all written documents that describe:

(a) The credit scoring techniques, including the factors considered and the weight (or score) given to each factor;
(b) The uses to which BC Hydro puts credit scoring for residential customers; and
(c) The specific decisions (e.g., whether to impose a deposit, whether to allow a deferred payment arrangement, etc.) to which BC Hydro puts the credit scoring analysis.

224.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

224.1 Please provide a list of the names and addresses of locations where a residential customer can walk in and make personal contact with a BC Hydro service representative that:

(a) Is capable of immediately responding to an inquiry about a residential bill;
(b) Can negotiate a deferred payment arrangement for an outstanding bill;
(c) Can negotiate a resolution to an outstanding shutoff for nonpayment; or
(d) Can negotiate a service reconnection after a shutoff for nonpayment.

225.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

225.1 For each office listed in response to the data request above, please provide the following:

(a) The actual number of BC Hydro personnel whose job it is to handle these walk-in customer contacts for each year for the past three years;
(b) The budgeted number of BC Hydro personnel whose job it would be to handle these walk-in customer contacts for each year for the past three years; and
(c) The number of walk-in customer contacts for each year for the past three years.

226.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

226.1 Please provide a list of each:

(a) Community served by BC Hydro, along with the number of residential customers served in that community.
(b) Postal code served by BC Hydro, along with the number of residential customers served in that postal code.

227.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

Preamble: BCOAPO understands that BC Hydro currently has the ability to place a Late Payment Charges (LPC) lock and Notice bypass on an account, which will waive any late payment charges and Dunning procedures.

227.1 Please confirm the existence of the LPC lock and Notice bypass.

227.2 Please confirm whether this is the same thing as a "Dunning lock".

227.3 What criteria does BCH use when deciding whether to put an LPC lock and bypass notice on an account?

227.4 How many accounts had such locks placed on them in 2014?

228.0 Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

Preamble: BCOAPO understands that BC Hydro offers a "third party notification" option, in which a customer can opt to have a third party notified if the customer is facing disconnection (i.e. customer has entered the Dunning process).

228.1 Has BC Hydro considered any ways to make this process simpler for customers to set up?

229.0 Reference: Exhibit B-1, Section 8.6, Table 8-6, p. 8-27
Load limiting

Preamble: BC Hydro states the following in Table 8-6, which compares the OEB Low Income Customer Rules with BC Hydro's current Electric Tariff Terms and Conditions:

"BC Hydro is investigating the feasibility of using smart meters to limit the allowable load to a customer. If practical, this would allow a customer facing disconnection to be provided with a minimal supply of electricity (i.e., to allow some heating) but also limit the exposure to further non-collection. If this approach is practical, BC Hydro would prefer a load limiting solution to a broad moratorium on winter disconnection"

229.1 Please describe what BC Hydro is doing to investigate the option of limiting the allowable load to a customer.

229.2 What are the results of BC Hydro's investigation into load limiting so far?

230.0 Reference: Exhibit B-1, Section 8.6.2.3
Ministry of Social Development and Social Innovation (MSDSI)

230.1 Is BC Hydro developing information sharing agreements with MSDSI?

230.2 If yes, what is the status of those agreements, and what will they cover?

231.0 Reference: Exhibit B-1, Section 8.6.2, p. 8-32
MSDSI

Preamble: BC Hydro states the following in the Application with regard to Extended Payment Deferrals and Instalment Plans for Customers Receiving MSDSI Direct Employment Assistance (EA):

"For a customer with an overdue amount incurred while receiving assistance from MSDSI, BC Hydro will make payment arrangements with MSDSI. MSDSI pays 50 percent of the overdue amount, including the reconnection charge if applicable, when the direct EA is set up and pays the remaining 50 per cent over 12 monthly instalments in addition to the customer's Equal Payment Plan bills"

231.1 Please confirm that for the above-referenced customers, MSDSI makes payments directly to BC Hydro, but this amount is deducted from the customer's Employment Assistance?

Please also confirm that the customer is not permitted to determine the amount (i.e. it is arranged by BC Hydro and MSDSI).

231.2 How did BC Hydro and MSDSI arrive at the 50% upfront, 50% in 12 monthly installments arrangement for repayment?

232.0 Reference: Exhibit B-1, Section 8.6.2.3, p. 8-33
MSDSI

Preamble: BC Hydro's Application states that "MSDSI indicated it has approximately 130,000 clients receiving income assistance, the majority being BC Hydro customers."

232.1 For F2013 to present, please provide the number, by year, of MSDSI clients that are also BC Hydro customers.

233.0 Reference: Exhibit B-1, Section 8.6.2.3, p. 8-33
MSDSI

Preamble: The Application states that "MSDSI directly pays BC Hydro for the electricity bills of 5,521 of those customers [receiving MSDSI assistance]."

233.1 Are the 5,521 customers whose bills are paid directly by MSDSI the result of payment arrangements to avoid disconnection or Equal Payment Plans?

234.0 Reference: Exhibit B-1, Chapter 8

234.1 Has BC Hydro considered any ways to make it easier for customers to opt for electronic billing?

234.2 For example, could BC Hydro regularly offer customers incentives such as draws and contests in order to encourage customers to switch to electronic billing?

235.0 Reference: Exhibit B-1, Chapter 8

235.1 Apart for street lights, does BC Hydro allow other types of attachments (e.g. by telephone and cable companies) to its poles?

235.2 If yes, does it charge for the use of its poles?

179.2.1 If yes, what is the charge and why is in not included as a Standard Charge?

179.2.2 If not, why not?

1.0 CHAPTER 1 INTRODUCTION

Reference: Exhibit B-1, pages 1-18 and 1-19

Default rates are rates that all customers pay unless they have options and choose to opt for another rate. (page 1-19)

1.1.1 Is there only one default rate (schedule) that is applicable to each Rate Class set out in Table 1-1?

RESPONSE:

There may be more than one default rate for a rate class where there are rates for more than one rate zone (e.g., Residential Service: the Zone I default rate is RS 1101 and the Zone II default rate is RS 1107). Please refer to BC Hydro's response to BCSEA IR 1.20.1 which provides a listing of rate schedules and indicates the default rates.

1.0 CHAPTER 1 INTRODUCTION

Reference: Exhibit B-1, pages 1-18 and 1-19

Default rates are rates that all customers pay unless they have options and choose to opt for another rate. (page 1-19)

1.1.1 Is there only one default rate (schedule) that is applicable to each Rate Class set out in Table 1-1?

1.1.1.1 If yes, please indicate for each class what that rate schedule is.

RESPONSE:

Please refer to BC Hydro's response to BCSEA IR 1.20.1.

1.0 CHAPTER 1 INTRODUCTION

Reference: Exhibit B-1, pages 1-18 and 1-19

Default rates are rates that all customers pay unless they have options and choose to opt for another rate. (page 1-19)

1.1.2 If there are rate classes where more than one default rate (schedule) applies, please indicate what these rate schedules are and describe the differences in the characteristics of the customers served under each.

RESPONSE:

Please refer to BC Hydro's response to BCSEA IR 1.20.1.

1.0 CHAPTER 1 INTRODUCTION

Reference: Exhibit B-1, pages 1-18 and 1-19

Default rates are rates that all customers pay unless they have options and choose to opt for another rate. (page 1-19)

1.1.2 If there are rate classes where more than one default rate (schedule) applies, please indicate what these rate schedules are and describe the differences in the characteristics of the customers served under each.

1.1.2.1 Please explain why each of these separate groups of customers is not considered to be a “rate class” for purposes of the RDA.

RESPONSE:

As shown in BC Hydro’s response to BCSEA IR 1.20.1, for each rate zone (i.e., Zone I, Zone II, and Zone IB) there is a single default rate.

As indicated in section 4.1 of Exhibit B-1, practicality of tariff administration is a consideration for segmentation. BC Hydro has not segmented its customer classes by rate zone because the revenues and costs associated with Zone II and/or Zone IB represent less than 1 per cent of BC Hydro’s revenue requirement.

2.0 CHAPTER 1 INTRODUCTION

Reference: Exhibit B-1, page 1-19

1.2.1 Please clarify, with reference to its Cost of Service Study (COS) results, what BC Hydro considers as "demand-related costs" (per line 24).

RESPONSE:

As described on page 3-4 of Exhibit B-1, demand-related costs are those "fixed costs that vary with kW demand". In the F2016 COS study, these include a portion of Generation costs (as determined by CP contribution), all Transmission costs (as determined by CP contribution) and a portion of Distribution costs (as determined by NCP contribution or direct assignment).

3.0 CHAPTER 1 INTRODUCTION

Reference: Exhibit B-1, page 1-20 and Section 2.2

Section 1.5.1 makes reference to the Bonbright's eight rate design criteria and then goes on to state that it prioritizes the three Bonbright rate design criteria set out in Table 1-2.

1.3.1 Please specifically describe how the factors identified in section 1.1.1 led to BC Hydro prioritizing the three Bonbright criteria set out in Table 1-2.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.6.1.

4.0 CHAPTER 1 INTRODUCTION

Reference: Exhibit B-1, page 1-21 & 1-21

1.4.1 How did BC Hydro determine the stakeholders that should be involved in its RDA workshop process?

RESPONSE:

BC Hydro invited the following to RDA pre-application workshops and other RDA engagement streams:

- **Intervener groups and interested parties representing Residential, General Service and Transmission Service customers that had participated in past BC Hydro rate design proceedings such as the 2005 Transmission Service Rate, 2007 RDA, 2008 RIB and 2009/2010 LGS proceedings, and the DCAT CPCN proceeding;**
- **Representatives from industry and municipal governments;**
- **A number of LGS and MGS customers;**
- **Other specific customers, including E-Plus customers and RS 1827 customers such as YVR, SFU and UBC; and**
- **Organizations representing the development community.**

5.0 CHAPTER 1 INTRODUCTION

Reference: Exhibit B-1, page 1-25

1.5.1 Please produce a schedule showing the derivation of the $950,000 impact to F2016 net income given that the updated Minimum Reconnection Charge will be implemented on an interim basis on December 1, 2015.

RESPONSE:

The impact to F2016 income is determined as follows:

Estimated Number of Reconnections per Month	Number of Months in Period December 1, 2015 to March 31, 2016	Estimated Total Reconnections in Period December 1, 2015 to March 31, 2016	Revenue Reduction per Reconnection, Calculated as $125-$30	Total Estimated Revenue Impact
A	**B**	**C=AxB**	**D**	**E=CxD**
2,500	**4**	**10,000**	**$95**	**$950,000**

6.0 CHAPTER 1 INTRODUCTION

Reference: Exhibit B-1, page 1-25

1.6.1 Please outline all instances where the F2016 COS was used to inform the rate design proposals set out in the current application.

RESPONSE:

A COS study informs:

- **How rate classes are defined (segmentation);**
- **How costs are assigned to each rate class (allocation); and**
- **How costs are assigned within each rate class (rate design).**

The F2016 COS informed the following proposals in Exhibit B-1:

1. **To divide the existing Street Lighting rate class into two new rate classes: customer-owned Street Lighting and BC Hydro-owned Street Lighting;**
2. **To leave the existing RIB rate basic charge recovery of customer-related costs at about 45 per cent;**
3. **To increase the SGS basic charge to recover about 45 per cent of BC Hydro's customer-related costs, with a one-time offsetting decrease in the energy rate set to maintain forecast revenue neutrality;**
4. **To propose a new rate for MGS customers with a flat demand charge set to recover about 35 per cent of BC Hydro's demand-related costs attributable to the MGS rate class;**
5. **To propose a new rate structure for LGS customers with a flat demand charge set to recover about 65 per cent of BC Hydro's demand-related costs attributable to the LGS rate class; and**
6. **To leave the existing RS 1823 demand charge recovery of demand-related costs at about 65 per cent.**

7.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-4

1.7.1 Please describe how, if at all, the requirement under subsection 60(1)(b) "to encourage public utilities to increase efficiency, reduce costs and enhance performance" is reflected in the rate design criteria (page 1-20) and the other considerations underpinning the 2015 RDA proposals.

RESPONSE:

The Bonbright efficiency criterion from a utility viewpoint was raised by Commission staff at Workshop 9a. BC Hydro's response was that it is sufficient from the utility viewpoint of efficient investments and operational decisions that the RIB rate (and RS 1823, and DSM programs and codes and standards)-related savings decrease the amount of supply side energy and capacity resources that would be required to meet service obligations (refer to the Workshop 9a/9b consideration memo, Exhibit B-1, Appendix C-3B, page 370 of 609).

At a more general level, subsection 60(1) of the *UCA*, together with subsections 59(1), 59(2), 59(4) and 59(5), require that rates established by the Commission relate to the characteristics of the service in respect of which they are charged, and the essential service characteristic that comes through in these provisions is economic cost.

8.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-4 through page 2-6

1.8.1 Please describe how, if at all, the British Columbia energy objectives (as set out in Section 2 of the Clean Energy Act) are relevant to the 2015 RDA and influenced BC Hydro's prioritization of the rate design criteria as set out in Table 1-2.

RESPONSE:

Please refer to BC Hydro's response to BCUC IRs 1.2.1 to 1.2.3.

9.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, Section 2.2, p. 2-5, Footnote 38
Rate Increases/Rate Caps

The Application states the following:

"The Rate Comparison Regulation, B.C. Reg. 119/2011 provides that BC Hydro is to provide the B.C. Minister of Energy and Mines with a report that includes a comparison of BC Hydro's rates with those of at least one public utility in each of 15 other jurisdictions in North America, including the provinces of Alberta, Manitoba, Ontario and Quebec, and the states of Washington, Oregon and California; https://www.canlii.org/en/bc/laws/regu/bc-reg-140-2009/latest/bc-reg-140-2009.html BC Hydro used the Rate Comparison Regulation to inform the scope of its various jurisdictional assessments as described in section 2.4.2of the Application"

1.9.1 Please provide a copy of the most recent Rate Comparison Report provided to the BC Minister of Energy and Mines.

RESPONSE:

A copy of BC Hydro's Electricity Rate Comparison Annual Report No. 8 is provided as Attachment 1 to this response.

BC Hydro
Power smart

Tom A. Loski
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

Via email: MEM.Minister@gov.bc.ca

November 4, 2015

Hon. Bill Bennett
Minister of Energy and Mines and
Minister Responsible for Core Review
PO Box 9060 Stn Prov Govt
Victoria BC V8W 9E3

Dear Minister Bennett:

RE: British Columbia Hydro and Power Authority (BC Hydro)
Electricity Rate Comparison Annual Report No. 8

BC Hydro writes to the Minister to file its Electricity Rate Comparison Annual Report (**Report**) which provides a comparison of BC Hydro's monthly bills and average prices for residential, commercial and industrial customers with other North American utilities as of April 1, 2015 (**Attachment A**) and therefore includes BC Hydro's 6 per cent rate increase that was effective on that date. The report is prepared in response to *Clean Energy Act* section 8(4), which states that:

> "The authority must provide to the minister, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of the extent to which the authority's electricity rates continue to be competitive with those other rates."

BC Hydro has adhered to the Province of British Columbia's Rate Comparison Regulation (Ministerial Order No. M167) (**Attachment B**). The Rate Comparison Regulation requires that the Report provide a comparison of BC Hydro's monthly electricity bills with at least one public utility in each of at least 15 other North American jurisdictions, including all of the following: the provinces of Alberta, Quebec, Ontario and Manitoba; and the states of Washington, Oregon and California. The comparison concerns the previous year's applicable rates for residential, commercial and industrial customers in Canadian funds. Additionally, BC Hydro is to provide its previous five years of applicable rates.

For efficiency and consistency in reported data, the Report consists of information taken from a Hydro-Quebec rate survey report titled "Comparison of Electricity Prices in Major North American Cities" in which BC Hydro participates. The Hydro-Quebec report is prepared each year. Monthly bills and average prices are calculated and submitted to Hydro-Quebec by the participating utilities using the rates that are in place as of April 1

of that current year. As such, some of the rates used may be interim rates that are approved and in effect at that time. The Hydro-Quebec report is typically available by the fall of the same year.

The Report indicates that BC Hydro's monthly bills and average prices remain within the first (i.e., lowest rate) quartile of the public utilities surveyed. On average, and based on the Hydro Quebec report, BC Hydro's residential rates are third lowest, small power (defined by Hydro Quebec as less than 100 kilowatts (**kW**)) are fifth lowest, medium power (defined by Hydro Quebec as 100 to 5,000 kW) are fourth lowest, and large power (defined by Hydro Quebec as greater than 5,000 kW) are fifth lowest. BC Hydro applicable rates for each category are listed in Table 11 of Attachment A.

For further information, please contact the undersigned.

Yours sincerely,

Original signed

Tom Loski
Chief Regulatory Officer

dr/rh

Enclosure (2)

Copy to:

British Columbia Utilities Commission
Attention: Ms. Erica Hamilton
Commission Secretary
Commission.secretary@bcuc.com

Ministry of Energy and Mines
Electricity & Alternative Energy Division
Attention: Les MacLaren
Assistant Deputy Minister
Les.MacLaren@gov.bc.ca

Ministry of Energy and Mines
Deputy Minister's Office
Attention: Elaine McKnight
Deputy Minister
ElaineMcKnight@gov.bc.ca

BC Hydro Electricity Rate Comparison Annual Report

Report No. 8

Attachment A

Rates as at April 1, 2015

Table of Contents

Monthly Bills and Average Prices as at April 1, 2015 1

List of Tables

Table 1 Residential Monthly Bills 4
Table 2 Small Power Monthly Bills 5
Table 3 Medium Power Monthly Bills 6
Table 4 Large Power Monthly Bills 7
Table 5 Residential Average Prices 8
Table 6 Small Power Average Prices 9
Table 7 Medium Power Average Prices 10
Table 8 Large Power Average Prices 11
Table 9 BC Hydro Monthly Bills Summary 12
Table 10 BC Hydro Average Prices Summary 13
Table 11 Corresponding BC Hydro Rate Schedules included in each Segment of the Hydro-Quebec Rate Survey 14
Table 12 BC Hydro Rankings Summary in Hydro-Quebec Rate Surveys, Out of 22 Utilities Surveyed 15

Monthly Bills and Average Prices as at April 1, 2015

This is the eighth Electricity Rate Comparison Annual Report (**Report**) prepared by BC Hydro in response to the Rate Comparison Regulation, issued by Ministerial Order No. M167 under the *Clean Energy Act* on June 28, 2011.[1] The Report provides a comparison of BC Hydro's monthly bills and average prices for residential, commercial and industrial customers with other North American utilities, including those in Alberta, Quebec, Ontario, Manitoba, Washington, Oregon and California in Canadian funds.[2]

Each year BC Hydro participates in a Hydro-Quebec rate comparison survey, submitting bill calculations based on electricity prices that are in place as of April 1 of the current year, and which may reflect approved interim rate increases. Hydro-Quebec compiles the information and provides the monthly bills and average prices for 12 Canadian utilities and 10 American utilities in an annual report. The Report provides survey information taken from the Hydro-Quebec report entitled *Comparison of Electricity Prices in Major North American Cities*.[3]

The Hydro-Quebec report provides the monthly bills, excluding taxes and non-utility levies, calculated for specific consumption points for four different customer segments: residential, small power, medium power and large power. The average price is also calculated, for each customer segment and specific consumption point, by dividing the monthly bill by the amount of monthly energy consumption. For example, if an electric bill for 1,000 kWh was calculated to be a monthly amount of $50, the average price would be $50 divided by 1,000 kWh, or 5 cents/kWh.

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1 The first Electricity Rate Comparison Annual Report was issued on June 10, 2009 in response to Ministerial Order No. M114, which was subsequently replaced by Ministerial Order No. M167.

2 Monthly bills and average prices for American utilities have been converted to Canadian dollars using the exchange rate as at 12 p.m. Eastern on April 1, 2015 of $0.7929 (C$1 = US$0.7929). The Canadian dollar had depreciated by 12.6 per cent relative to the U.S. dollar since April 1, 2014.

3 http://www.hydroquebec.com/publications/en/docs/comparaison-electricity-prices/comp_2015_en.pdf.

The monthly bills for customers are presented in Table 1, Table 2, Table 3 and Table 4. The average prices for customers are presented in Table 5, Table 6, Table 7 and Table 8. BC Hydro's monthly bills and average prices over the past five years are summarized in Table 9 and Table 10.

The Hydro-Quebec residential segment includes calculations for BC Hydro's residential customers. The Hydro-Quebec small power segment includes calculations for both BC Hydro's general service under 35 kW customers and general service 35 kW and over customers, while the medium power segment includes calculations for BC Hydro's general service 35 kW and over customers. Lastly, the Hydro-Quebec large power segment includes calculations for BC Hydro's general service 35 kW and over customers and transmission service customers. Table 11 shows the specific BC Hydro rate schedules that have been included in each Hydro Quebec segment. Table 12 summarizes BC Hydro's relative rankings in each rate class during the last five years of participation in the survey.

Based on the data from the Hydro-Quebec survey, BC Hydro's monthly bills and average prices for all customer segments are within the first (i.e., lowest rate) quartile of utilities, with low rates providing a competitive advantage to customers in BC Hydro's service area. The rankings of the top five participating utilities with the lowest monthly bills and average prices are noted in the tables. Out of the 22 utilities providing data, BC Hydro's monthly bills and average price rankings against the other utilities using the Hydro-Quebec report for April 1, 2015 data are as follows:

Rate Class & Usage	Ranking at April 1, 2015
Residential	
Residential - 625 kWh	3
Residential - 750 kWh	3
Residential - 1,000 kWh	3
Residential - 2,000 kWh	7
Residential - 3,000 kWh	8
Small Power	
Small Power - 750 kWh/6 kW	5
Small Power - 2,000 kWh/14 kW	6
Small Power - 10,000 kWh/40 kW	6
Small Power - 14,000 kWh/100 kW	5
Small Power - 25,000 kWh/100 kW	6
Medium Power	
Medium Power - 100,000 kWh/500 kW	4
Medium Power - 200,000 kWh/500 kW	3
Medium Power - 200,000 kWh/1,000 kW	4
Medium Power - 400,000 kWh/1,000 kW	4
Medium Power - 1,170,000 kWh/2,500 kW	4
Large Power	
Large Power - 2,340 MWh/5,000 kW/25 kV	4
Large Power - 3,060 MWh/5,000 kW/25 kV	5
Large Power - 5,760 MWh/10,000 kW/120 kV	6
Large Power - 17,520 MWh//30,000 kW/120 kV	7
Large Power - 23,400 MWh/50,000 kW/120 kV	7
Large Power - 30,600 MWh/50,000 kW /120 kV	7

Table 1 Residential Monthly Bills

Hydro-Quebec Electricity Prices Comparison Report – Residential
Monthly Bills as of April 1, 2015
CDN $/Month

Utility	City	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Hydro-Quebec	Montreal, QC	(1st) 48	(1st) 55	(1st) 72	(2nd) 158	(2nd) 244
Manitoba Hydro	Winnipeg, MB	(2nd) 53	(2nd) 63	(2nd) 81	(1st) 155	(1st) 229
BC Hydro	Vancouver, BC	(3rd) 58	(3rd) 72	(3rd) 103	(7th) 228	(8th) 354
EPCOR Energy	Edmonton, AB	81	92	(4th) 115	(3rd) 208	(3rd) 301
Newfoundland Power[1]	St. John's, NL	(5th) 78	(5th) 90	(5th) 116	(5th) 217	(5th) 318
Enmax	Calgary, AB	81	93	117	(4th) 212	(4th) 307
NB Power	Moncton, NB	85	97	123	225	328
Seattle City Light	Seattle, WA	(4th) 68	(4th) 87	124	274	424
Florida Power and Light[2]	Miami, FL	81	95	123	263	403
CenterPoint Energy[2]	Houston, TX	94	108	124	236	349
SaskPower	Regina, SK	97	113	144	267	391
Nashville Electric Service	Nashville, TN	96	112	145	274	404
Toronto Hydro	Toronto, ON	94	110	143	280	417
Pacific Power and Light	Portland, OR	92	108	139	298	457
Hydro Ottawa	Ottawa, ON	97	114	149	288	427
Maritime Electric	Charlottetown, PE	107	123	156	288	392
Commonwealth Edison[2]	Chicago, IL	112	131	168	278	407
Nova Scotia Power	Halifax, NS	104	123	160	310	459
DTE Electric[2]	Detroit, MI	111	133	178	357	536
Consolidated Edison[2]	New York, NY	188	222	289	558	827
NSTAR Electric & Gas	Boston, MA	191	227	300	593	885
Pacific Gas and Electric[2]	San Francisco, CA	156	209	277	699	1,122

1) Newfoundland Power rates.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Note: Bill calculations exclude taxes and levies. BC Hydro's bill calculation includes the rate rider. The top five participating utilities with the lowest monthly bills are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 2 Small Power Monthly Bills

Hydro-Quebec Electricity Prices Comparison Report – Small Power
Monthly Bills as of April 1, 2015
CDN $/Month

Utility	City	6 kW 750 kWh 17% load factor	14 kW 2,000 kWh 20% load factor	40 kW 10,000 kWh 35% load factor	100 kW 14,000 kWh 19% load factor	100 kW 25,000 kWh 35% load factor
Manitoba Hydro	Winnipeg, MB	(2nd) 78	(1st) 175	(1st) 795	(3rd) 1,588	(2nd) 2,080
Enmax	Calgary, AB	107	(4th) 220	(2nd) 811	(1st) 1,318	(1st) 1,748
Seattle City Light	Seattle, WA	(1st) 76	(2nd) 202	(4th) 1,008	(2nd) 1,402	(3rd) 2,282
Hydro-Quebec	Montreal, QC	(3rd) 85	(3rd) 205	(3rd) 977	(4th) 1,798	(5th) 2,655
BC Hydro	Vancouver, BC	(5th) 92	(6th) 233	(6th) 1,075	(5th) 1,836	(6th) 2,658
CenterPoint Energy[2]	Houston, TX	(4th) 88	289	(5th) 1,028	1,842	(4th) 2,519
EPCOR Energy	Edmonton, AB	95	(5th) 230	1,089	1,993	2,742
Newfoundland Power[1]	St. John's, NL	104	269	1,162	2,054	2,979
Florida Power and Light[2]	Miami, FL	101	253	1,259	2,341	3,110
SaskPower	Regina, SK	116	264	1,209	2,330	3,173
NB Power	Moncton, NB	116	273	1,296	2,255	3,234
Pacific Power and Light	Portland, OR	123	289	1,302	2,193	3,197
Hydro Ottawa	Ottawa, ON	118	288	1,482	2,147	2,991
DTE Electric[2]	Detroit, MI	117	295	1,414	1,973	3,510
Toronto Hydro	Toronto, ON	127	301	1,385	2,207	3,053
Commonwealth Edison[2]	Chicago, IL	130	303	1,457	2,381	3,584
Nova Scotia Power	Halifax, NS	121	295	1,538	2,707	3,846
Nashville Electric Service	Nashville, TN	140	320	1,471	3,034	4,017
Maritime Electric	Charlottetown, PE	146	350	1,630	2,856	4,009
Pacific Gas and Electric[2]	San Francisco, CA	203	520	2,516	4,127	6,030
NSTAR Electric & Gas	Boston, MA	224	579	3,000	5,545	7,851
Consolidated Edison[2]	New York, NY	241	779	2,655	5,254	6,570

1) Newfoundland Power rates.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Note: Bill calculations exclude taxes and levies. BC Hydro's bill calculation includes the rate rider. The top five participating utilities with the lowest monthly bills are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 3 Medium Power Monthly Bills

Hydro-Quebec Electricity Prices Comparison Report – Medium Power
Monthly Bills as of April 1, 2015
CDN $/Month

Utility	City	500 kW 100,000 kWh 28% load factor	500 kW 200,000 kWh 56% load factor	1000 kW 200,000 kWh 28% load factor	1000 kW 400,000 kWh 56% load factor	2500 kW[1] 1,170,000 kWh 65% load factor
Manitoba Hydro	Winnipeg, MB	(1st) 8,798	(1st) 12,350	(2nd) 17,395	(1st) 24,499	(2nd) 60,512
Enmax	Calgary, AB	(2nd) 8,808	(2nd) 12,618	(1st) 17,063	(2nd) 24,684	(1st) 60,031
Seattle City Light	Seattle, WA	(3rd) 9,409	(5th) 17,405	(3rd) 18,323	(5th) 34,097	97,219
BC Hydro	Vancouver, BC	(4th) 10,794	(3rd) 16,181	(4th) 21,720	(4th) 32,493	(4th) 88,570
Hydro-Quebec	Montreal, QC	11,940	(4th) 16,925	23,880	(3rd) 31,494	(3rd) 78,106
EPCOR Energy[2]	Edmonton, AB	12,754	18,242	23,498	34,473	(5th) 92,496
CenterPoint Energy[4]	Houston, TX	(5th) 11,819	17,980	25,931	38,252	99,791
Newfoundland Power[3]	St. John's, NL	12,126	20,115	(5th) 22,662	38,181	105,786
Hydro Ottawa	Ottawa, ON	11,992	19,661	23,722	39,060	113,690
Commonwealth Edison[4]	Chicago, IL	13,574	20,200	26,636	38,984	103,740
Pacific Power and Light	Portland, OR	13,562	20,841	25,875	39,759	101,563
Toronto Hydro	Toronto, ON	13,077	20,764	25,834	41,068	113,641
Florida Power and Light[4]	Miami, FL	14,019	20,389	27,963	40,703	109,937
SaskPower	Regina, SK	14,183	20,912	28,349	41,807	101,998
DTE Electric[4]	Detroit, MI	13,995	21,800	27,974	43,168	110,172
NB Power	Moncton, NB	13,929	22,829	27,854	45,654	129,259
Nova Scotia Power	Halifax, NS	17,090	25,652	34,179	51,303	132,545
Nashville Electric Service	Nashville, TN	17,005	25,400	33,766	50,555	143,340
Maritime Electric[4]	Charlottetown, PE	17,249	27,739	34,454	55,434	156,352
NSTAR Electric & Gas	Boston, MA	24,491	35,078	48,772	69,945	190,887
Pacific Gas and Electric[4]	San Francisco, CA	29,527	41,601	56,550	79,334	161,568
Consolidated Edison[4]	New York, NY	29,676	41,637	59,306	83,228	218,988

1) Supply voltage of 25 kV.
2) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
3) Newfoundland Power rates.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Note: Bill calculations exclude taxes and levies. BC Hydro's bill calculation includes the rate rider. The top five participating utilities with the lowest monthly bills are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 4 Large Power Monthly Bills

Hydro-Quebec Electricity Prices Comparison Report – Large Power
Monthly Bills as of April 1, 2015
CDN $000/Month

Utility	City	5,000 kW 2,340,000 kWh 25 kV 65% load factor	5,000 kW 3,060,000 kWh 25 kV 85% load factor	10,000 kW 5,760,000 kWh 120 kV 80% load factor	17,520,000 kWh 120 kV 81% load factor	23,400,000 kWh 120 kV 65% load factor	30,600,000 kWh 120 kV 85% load factor
Manitoba Hydro	Winnipeg, MB	(2nd) 118.8	(1st) 142.8	(1st) 235.2	(1st) 712.9	(1st) 1,013.6	(1st) 1,230.2
Enmax	Calgary, AB	(1st) 117.9	(2nd) 145.6	(3rd) 276.7	(3rd) 837.9	(3rd) 1,172.8	(3rd) 1,450.0
Hydro-Quebec	Montreal, QC	(3rd) 134.8	(3rd) 158.3	(4th) 287.9	(5th) 871.6	(5th) 1,263.6	(5th) 1,498.3
EPCOR Energy[1]	Edmonton, AB	(5th) 178.1	(4th) 213.4	(2nd) 257.5	(2nd) 757.1	(2nd) 1,069.1	(2nd) 1,292.7
BC Hydro	Vancouver, BC	(4th) 177.3	(5th) 215.5	(6th) 341.4	(7th) 1,034.9	(7th) 1,462.9	(7th) 1,788.1
Newfoundland Power[2]	St. John's, NL	208.9	264.8	495.7	(4th) 844.4	(4th) 1,194.2	(4th) 1,458.9
Toronto Hydro	Toronto, ON	217.2	282.2	(5th) 328.2	987.5	1,415.9	1,698.7
SaskPower	Regina, SK	195.7	238.8	387.3	1,161.1	1,623.7	2,004.7
NB Power	Moncton, NB	192.7	228.9	418.9	1,268.6	1,827.3	2,183.7
CenterPoint Energy[3]	Houston, TX	197.1	242.3	436.8	1,319.7	1,843.8	2,283.3
Commonwealth Edison[3]	Chicago, IL	206.7	251.2	458.1	1,273.7	1,764.1	2,208.6
Seattle City Light	Seattle, WA	194.6	251.0	443.1	1,346.1	1,818.2	2,344.5
Pacific Power and Light	Portland, OR	201.7	246.4	459.0	1,385.5	1,973.8	2,387.8
Hydro Ottawa	Ottawa, ON	230.9	284.7	593.9	1,209.2	1,598.7	1,875.1
Florida Power and Light[3]	Miami, FL	219.6	263.5	451.4	1,363.3	1,952.6	2,347.7
DTE Electric[3]	Detroit, MI	219.9	260.1	484.5	1,465.8	2,122.4	2,519.9
Maritime Electric[3]	Charlottetown, PE	225.3	272.3	521.1	1,579.1	2,253.0	2,723.2
Nova Scotia Power	Halifax, NS	249.3	306.6	584.6	1,773.0	2,493.5	3,066.5
Nashville Electric Service	Nashville, TN	288.2	348.1	564.2	1,689.2	2,512.0	2,886.1
Pacific Gas and Electric[3]	San Francisco, CA	319.9	388.2	739.8	2,237.2	3,176.7	3,859.9
NSTAR Electric & Gas	Boston, MA	361.4	436.5	835.2	2,529.9	3,611.8	4,362.3
Consolidated Edison[3]	New York, NY	437.8	519.4	997.9	3,020.7	4,377.3	5,193.0

1) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
2) Newfoundland Power and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Note: Bill calculations exclude taxes and levies. BC Hydro's bill calculation includes the rate rider. The top five participating utilities with the lowest monthly bills are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 5 Residential Average Prices

Hydro-Quebec Electricity Prices Comparison Report – Residential
Average Prices as of April 1, 2015
CDN ¢/kWh

Utility	City	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Hydro-Quebec	Montreal, QC	(1st) 7.63	(1st) 7.31	(1st) 7.19	(2nd) 7.90	(2nd) 8.13
Manitoba Hydro	Winnipeg, MB	(2nd) 8.55	(2nd) 8.35	(2nd) 8.11	(1st) 7.75	(1st) 7.62
BC Hydro	Vancouver, BC	(3rd) 9.27	(3rd) 9.54	(3rd) 10.29	(7th) 11.42	(8th) 11.80
EPCOR Energy	Edmonton, AB	12.91	12.30	(4th) 11.55	(3rd) 10.41	(3rd) 10.04
Newfoundland Power[1]	St. John's, NL	(5th) 12.41	(5th) 12.03	(4th) 11.55	(5th) 10.84	(5th) 10.60
Enmax	Calgary, AB	12.94	12.37	11.66	(4th) 10.58	(4th) 10.23
NB Power	Moncton, NB	13.53	12.98	12.30	11.27	10.93
Seattle City Light	Seattle, WA	(4th) 10.90	(4th) 11.58	12.44	13.72	14.14
Florida Power and Light[2]	Miami, FL	12.88	12.63	12.31	13.15	13.43
CenterPoint Energy[2]	Houston, TX	15.02	14.40	12.36	11.81	11.62
SaskPower	Regina, SK	15.59	15.05	14.37	13.36	13.02
Toronto Hydro	Toronto, ON	15.06	14.71	14.31	13.99	13.89
Nashville Electric Service	Nashville, TN	15.35	14.95	14.45	13.70	13.46
Pacific Power and Light	Portland, OR	14.74	14.38	13.94	14.91	15.23
Hydro Ottawa	Ottawa, ON	15.44	15.18	14.86	14.38	14.22
Maritime Electric[2]	Charlottetown, PE	17.09	16.44	15.62	14.39	13.05
Nova Scotia Power	Halifax, NS	16.68	16.39	16.03	15.49	15.31
Commonwealth Edison[2]	Chicago, IL	18.00	17.46	16.79	13.92	13.56
DTE Electric[2]	Detroit, MI	17.69	17.72	17.77	17.83	17.86
Consolidated Edison[2]	New York, NY	30.10	29.57	28.90	27.91	27.57
NSTAR Electric & Gas	Boston, MA	30.52	30.31	30.03	29.63	29.49
Pacific Gas and Electric[2]	San Francisco, CA	25.00	27.87	27.69	34.97	37.40

1) Newfoundland Power rates.

2) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Note: The top five participating utilities with the lowest average prices are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 6 Small Power Average Prices

Hydro-Quebec Electricity Prices Comparison Report – Small Power
Average Prices as of April 1, 2015
CDN ¢/kWh

Utility	City	6 kW 750 kWh 17% load factor	14 kW 2,000 kWh 20% load factor	40 kW 10,000 kWh 35% load factor	100 kW 14,000 kWh 19% load factor	100 kW 25,000 kWh 35% load factor
Manitoba Hydro	Winnipeg, MB	(2nd) 10.38	(1st) 8.74	(1st) 7.95	(3rd) 11.35	(2nd) 8.32
Enmax	Calgary, AB	14.32	(4th) 11.00	(2nd) 8.11	(1st) 9.41	(1st) 6.99
Seattle City Light	Seattle, WA	(1st) 10.08	(2nd) 10.08	(4th) 10.08	(2nd) 10.01	(3rd) 9.13
Hydro-Quebec	Montreal, QC	(3rd) 11.29	(3rd) 10.27	(3rd) 9.77	(4th) 12.84	(5th) 10.62
BC Hydro	Vancouver, BC	(5th) 12.23	(6th) 11.63	(6th) 10.75	(5th) 13.12	(6th) 10.63
CenterPoint Energy[2]	Houston, TX	(4th) 11.78	14.45	(5th) 10.28	13.15	(4th) 10.08
EPCOR Energy	Edmonton, AB	12.71	(5th) 11.48	10.89	14.23	10.97
Newfoundland Power[1]	St. John's, NL	13.92	13.45	11.62	14.67	11.92
Florida Power and Light[2]	Miami, FL	13.45	12.67	12.59	16.72	12.44
SaskPower	Regina, SK	15.48	13.19	12.09	16.65	12.69
NB Power	Moncton, NB	15.46	13.65	12.96	16.11	12.94
Pacific Power and Light	Portland, OR	16.34	14.46	13.01	15.67	12.79
Hydro Ottawa	Ottawa, ON	15.73	14.40	14.82	15.34	11.96
DTE Electric[2]	Detroit, MI	15.60	14.76	14.14	14.09	14.04
Toronto Hydro	Toronto, ON	16.90	15.05	13.85	15.77	12.21
Commonwealth Edison[2]	Chicago, IL	17.32	15.13	14.57	17.01	14.34
Nova Scotia Power	Halifax, NS	16.13	14.77	15.38	19.34	15.38
Nashville Electric Service	Nashville, TN	18.66	15.99	14.71	21.67	16.07
Maritime Electric[2]	Charlottetown, PE	19.53	17.48	16.30	20.40	16.04
Pacific Gas and Electric[2]	San Francisco, CA	27.05	26.01	25.16	29.48	24.12
NSTAR Electric & Gas	Boston, MA	29.88	28.94	30.00	39.60	31.40
Consolidated Edison[2]	New York, NY	32.10	38.97	26.55	37.53	26.28

1) Newfoundland Power rates.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Note: The top five participating utilities with the lowest average prices are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 7 Medium Power Average Prices

Hydro-Quebec Electricity Prices Comparison Report – Medium Power
Average Prices as of April 1, 2015
CDN ¢/kWh

Utility	City	500 kW 100,000 kWh 28% load factor	500 kW 200,000 kWh 56% load factor	1000 kW 200,000 kWh 28% load factor	1000 kW 400,000 kWh 56% load factor	2500 kW[1] 1,170,000 kWh 65% load factor
Manitoba Hydro	Winnipeg, MB	(1st) 8.80	(1st) 6.18	(2nd) 8.70	(1st) 6.12	(2nd) 5.17
Enmax	Calgary, AB	(2nd) 8.81	(2nd) 6.31	(1st) 8.53	(2nd) 6.17	(1st) 5.13
Seattle City Light	Seattle, WA	(3rd) 9.41	(5th) 8.70	(3rd) 9.16	(5th) 8.52	8.31
BC Hydro	Vancouver, BC	(4th) 10.79	(3rd) 8.09	(4th) 10.86	(4th) 8.12	(4th) 7.57
Hydro-Quebec	Montreal, QC	11.94	(4th) 8.46	11.94	(3rd) 7.87	(3rd) 6.68
EPCOR Energy[2]	Edmonton, AB	12.75	9.12	11.75	8.62	(5th) 7.91
CenterPoint Energy[4]	Houston, TX	(5th) 11.82	8.99	12.97	9.56	8.53
Newfoundland Power[3]	St. John's, NL	12.13	10.06	(5th) 11.33	9.55	9.04
Hydro Ottawa	Ottawa, ON	11.99	9.83	11.86	9.77	9.72
Commonwealth Edison[4]	Chicago, IL	13.57	10.10	13.32	9.75	8.87
Pacific Power and Light	Portland, OR	13.56	10.42	12.94	9.94	8.68
Toronto Hydro	Toronto, ON	13.08	10.38	12.92	10.27	9.71
Florida Power and Light[4]	Miami, FL	14.02	10.19	13.98	10.18	9.40
SaskPower	Regina, SK	14.18	10.46	14.17	10.45	8.72
DTE Electric[4]	Detroit, MI	13.99	10.90	13.99	10.79	9.42
NB Power	Moncton, NB	13.93	11.41	13.93	11.41	11.05
Nova Scotia Power	Halifax, NS	17.09	12.83	17.09	12.83	11.33
Nashville Electric Service	Nashville, TN	17.01	12.70	16.88	12.64	12.25
Maritime Electric[4]	Charlottetown, PE	17.25	13.87	17.23	13.86	13.36
NSTAR Electric & Gas	Boston, MA	24.49	17.54	24.39	17.49	16.32
Pacific Gas and Electric[4]	San Francisco, CA	29.53	20.80	28.28	19.83	13.81
Consolidated Edison[4]	New York, NY	29.68	20.82	29.65	20.81	18.72

1) Supply voltage of 25 kV.
2) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
3) Newfoundland Power rates.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Note: The top five participating utilities with the lowest average prices are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 8 Large Power Average Prices

Hydro-Quebec Electricity Prices Comparison Report – Large Power
Average Prices as of April 1, 2015
CDN ¢/kWh

Utility	City	5,000 kW 2,340,000 kWh 25 kV 65% load factor	5,000 kW 3,060,000 kWh 25 kV 85% load factor	10,000 kW 5,760,000 kWh 120 kV 80% load factor	17,520,000 kWh 120 kV 81% load factor	23,400,000 kWh 120 kV 65% load factor	30,600,000 kWh 120 kV 85% load factor
Manitoba Hydro	Winnipeg, MB	(2nd) 5.08	(1st) 4.67	(1st) 4.08	(1st) 4.07	(1st) 4.33	(1st) 4.02
Enmax	Calgary, AB	(1st) 5.04	(2nd) 4.76	(3rd) 4.80	(3rd) 4.78	(3rd) 5.01	(3rd) 4.74
Hydro-Quebec	Montreal, QC	(3rd) 5.76	(3rd) 5.17	(4th) 5.00	(5th) 4.97	(5th) 5.40	(5th) 4.90
EPCOR Energy[1]	Edmonton, AB	(5th) 7.61	(4th) 6.97	(2nd) 4.47	(2nd) 4.32	(2nd) 4.57	(2nd) 4.22
BC Hydro	Vancouver, BC	(4th) 7.58	(5th) 7.04	(6th) 5.93	(7th) 5.91	(7th) 6.25	(7th) 5.84
Newfoundland Power[2]	St. John's, NL	8.93	8.65	8.61	(4th) 4.82	(4th) 5.10	(4th) 4.77
Toronto Hydro	Toronto, ON	9.28	9.22	(5th) 5.70	5.64	6.05	5.55
SaskPower	Regina, SK	8.36	7.81	6.72	6.63	6.94	6.55
NB Power	Moncton, NB	8.24	7.48	7.27	7.24	7.81	7.14
CenterPoint Energy[3]	Houston, TX	8.42	7.92	7.58	7.53	7.88	7.46
Commonwealth Edison[3]	Chicago, IL	8.83	8.21	7.95	7.27	7.54	7.22
Seattle City Light	Seattle, WA	8.31	8.20	7.69	7.68	7.77	7.66
Pacific Power and Light	Portland, OR	8.62	8.05	7.97	7.91	8.43	7.80
Hydro Ottawa	Ottawa, ON	9.87	9.30	10.31	6.90	6.83	6.13
Florida Power and Light[3]	Miami, FL	9.38	8.61	7.84	7.78	8.34	7.67
DTE Electric[3]	Detroit, MI	9.40	8.50	8.41	8.37	9.07	8.24
Maritime Electric[3]	Charlottetown, PE	9.63	8.90	9.05	9.01	9.63	8.90
Nova Scotia Power	Halifax, NS	10.66	10.02	10.15	10.12	10.66	10.02
Nashville Electric Service	Nashville, TN	12.32	11.37	9.79	9.64	10.74	9.43
Pacific Gas and Electric[3]	San Francisco, CA	13.67	12.69	12.84	12.77	13.58	12.61
NSTAR Electric & Gas	Boston, MA	15.45	14.26	14.50	14.44	15.43	14.26
Consolidated Edison[3]	New York, NY	18.71	16.97	17.32	17.24	18.71	16.97

1) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
2) Newfoundland Power and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.

Note: The top five participating utilities with the lowest average prices are ranked in the table above, from lowest to highest. The sort order indicates the utility's overall ranking in the category.

Table 9 BC Hydro Monthly Bills Summary

BC Hydro Monthly Bills Summary for the Previous Five Years CDN$/Month					
Vancouver, BC	**April 1, 2011 [1]**	**April 1, 2012 [2]**	**April 1, 2013 [3]**	**April 1, 2014 [4]**	**April 1, 2015 [5]**
Residential					
625 kWh	47	49	50	55	58
750 kWh	58	61	62	67	72
1,000 kWh	83	88	89	97	103
2,000 kWh	181	195	198	215	228
3,000 kWh	280	302	306	334	354
Small Power					
750 kWh/6 kW	74	78	79	86	92
2,000 kWh/14 kW	186	198	201	219	233
10,000 kWh/40 kW	923	973	960	1,015	1,075
14,000 kWh/100 kW	1,558	1,645	1,632	1,734	1,836
25,000 kWh/100 kW	2,093	2,245	2,294	2,510	2,658
Medium Power					
100,000 kWh/500 kW	8,707	9,371	9,563	10,207	10,794
200,000 kWh/500 kW	13,073	14,106	14,414	15,310	16,181
200,000 kWh/1,000 kW	17,512	18,831	19,207	20,534	21,720
400,000 kWh/1,000 kW	26,245	28,302	28,909	30,740	32,493
1,170,000 kWh/2,500 kW	71,443	77,100	78,776	83,763	88,570
Large Power					
2,340 MWh/5,000 kW/25 kV	142,983	154,289	157,631	167,643	177,269
3,060 MWh/5,000 kW/25 kV	173,950	187,873	192,035	203,833	215,470
5,760 MWh/10,000 kW/120 kV	273,626	291,237	295,443	322,044	341,362
17,520 MWh//30,000 kW/120 kV	829,577	882,967	895,720	976,368	1,034,937
23,400 MWh/50,000 kW/120 kV	1,172,581	1,248,056	1,266,076	1,380,070	1,462,863
30,600 MWh/50,000 kW /120 kV	1,433,332	1,525,576	1,547,611	1,686,954	1,788,148

1) Rates used reflect an 8.00 per cent approved increase effective May 1, 2011.
2) Rates used reflect a 3.91 per cent approved increase effective April 1, 2012.
3) Rates used reflect a 1.44 per cent approved increase effective April 1, 2013.
4) Rates used reflect a 9.00 per cent approved increase effective April 1, 2014.
5) Rates used reflect a 6.00 per cent approved increase effective April 1, 2015.

Note: Bill calculations exclude taxes and levies and include the rate rider.

Table 10 BC Hydro Average Prices Summary

BC Hydro Average Prices Summary for the Previous Five Years CDN¢/kWh					
Vancouver, BC	**April 1, 2011 [1]**	**April 1, 2012 [2]**	**April 1, 2013 [3]**	**April 1, 2014 [4]**	**April 1, 2015 [5]**
Residential					
625 kWh	7.56	7.91	8.03	8.75	9.27
750 kWh	7.74	8.14	8.26	9.00	9.54
1,000 kWh	8.27	8.78	8.91	9.71	10.29
2,000 kWh	9.07	9.74	9.88	10.77	11.42
3,000 kWh	9.33	10.06	10.21	11.12	11.80
Small Power					
750 kWh/6 kW	9.80	10.43	10.58	11.53	12.23
2,000 kWh/14 kW	9.32	9.92	10.06	10.97	11.63
10,000 kWh/40 kW	9.23	9.73	9.60	10.15	10.75
14,000 kWh/100 kW	11.13	11.75	11.66	12.39	13.12
25,000 kWh/100 kW	8.37	8.98	9.18	10.04	10.63
Medium Power					
100,000 kWh/500 kW	8.71	9.37	9.56	10.21	10.79
200,000 kWh/500 kW	6.54	7.05	7.21	7.66	8.09
200,000 kWh/1,000 kW	8.76	9.42	9.60	10.27	10.86
400,000 kWh/1,000 kW	6.56	7.08	7.23	7.69	8.12
1,170,000 kWh/2,500 kW	6.11	6.59	6.73	7.16	7.57
Large Power					
2,340 MWh/5,000 kW/25 kV	6.11	6.59	6.74	7.16	7.58
3,060 MWh/5,000 kW/25 kV	5.68	6.14	6.28	6.66	7.04
5,760 MWh/10,000 kW/120 kV	4.75	5.06	5.13	5.59	5.93
17,520 MWh//30,000 kW/120 kV	4.74	5.04	5.11	5.57	5.91
23,400 MWh/50,000 kW/120 kV	5.01	5.33	5.41	5.90	6.25
30,600 MWh/50,000 kW /120 kV	4.68	4.99	5.06	5.51	5.84

1) Rates used reflect an 8.00 per cent approved increase effective May 1, 2011.
2) Rates used reflect a 3.91 per cent approved increase effective April 1, 2012.
3) Rates used reflect a 1.44 per cent approved increase effective April 1, 2013.
4) Rates used reflect a 9.00 per cent approved increase effective April 1, 2014.
5) Rates used reflect a 6.00 per cent approved increase effective April 1, 2015.

Table 11 Corresponding BC Hydro Rate Schedules included in each Segment of the Hydro-Quebec Rate Survey

Hydro Quebec Segment	Corresponding BC Hydro Rate Schedule
Residential	
625 kWh	RS 1101
750 kWh	RS 1101
1,000 kWh	RS 1101
2,000 kWh	RS 1101
3,000 kWh	RS 1101
Small Power	
750 kWh/6 kW	RS 1300
2,000 kWh/14 kW	RS 1300
10,000 kWh/40 kW	RS 1500
14,000 kWh/100 kW	RS 1500
25,000 kWh/100 kW	RS 1500
Medium Power	
100,000 kWh/500 kW	RS 1600
200,000 kWh/500 kW	RS 1600
200,000 kWh/1,000 kW	RS 1600
400,000 kWh/1,000 kW	RS 1600
1,170,000 kWh/2,500 kW	RS 1611
Large Power	
2,340,000 kWh/5,000 kW/25 kV	RS 1611
3,060,000 kWh/5,000 kW/25 kV	RS 1611
5,760,000 kWh/10,000 kW/120 kV	RS 1823
17,520,000 kWh/30,000 kW/120 kV	RS 1823
23,400,000 kWh/50,000 kW/120 kV	RS 1823
30,600,000 kWh/50,000 kW/120 kV	RS 1823

Table 12 BC Hydro Rankings Summary in Hydro-Quebec Rate Surveys, Out of 22 Utilities Surveyed

BC Hydro Rates Comparisons Ranking Summary for Previous Years

Vancouver, BC	April 1, 2011	April 1, 2012	April 1, 2013	April 1, 2014	April 1, 2015
Residential					
625 kWh	2	4	3	3	3
750 kWh	3	4	3	3	3
1,000 kWh	3	4	3	3	3
2,000 kWh	3	7	5	5	7
3,000 kWh	4	7	6	7	8
Small Power					
750 kWh/6 kW	2	6	6	5	5
2,000 kWh/14 kW	3	5	5	4	6
10,000 kWh/40 kW	3	7	5	4	6
14,000 kWh/100 kW	5	5	4	5	5
25,000 kWh/100 kW	3	4	4	4	6
Medium Power					
100,000 kWh/500 kW	3	5	4	3	4
200,000 kWh/500 kW	3	5	4	3	3
200,000 kWh/1,000 kW	3	5	4	3	4
400,000 kWh/1,000 kW	3	4	4	4	4
1,170,000 kWh/2,500 kW	2	5	6	4	4
Large Power					
2,340 MWh/5,000 kW/25 kV	3	6	6	4	4
3,060 MWh/5,000 kW/25 kV	3	6	6	3	5
5,760 MWh/10,000 kW/120 kV	2	3	3	3	6
17,520 MWh//30,000 kW/120 kV	3	4	5	4	7
23,400 MWh/50,000 kW/120 kV	3	4	5	4	7
30,600 MWh/50,000 kW /120 kV	3	4	5	4	7

BC Hydro Electricity Rate Comparison Annual Report

Report No. 8

Attachment B

Ministerial Order No. M 167

PROVINCE OF BRITISH COLUMBIA

REGULATION OF THE MINISTER OF ENERGY AND MINES AND MINISTER RESPONSIBLE FOR HOUSING

Clean Energy Act

Ministerial Order No. M 167

I, Rich Coleman, Minister of Energy and Mines and Minister Responsible for Housing, order that the Rate Comparison Regulation, B.C. Reg. 140/2009, is repealed, and the following Rate Comparison Regulation is made.

RATE COMPARISON REGULATION

Definition

1 In this regulation:

"Act" means the *Clean Energy Act*;

"applicable rates" means, with respect to a public utility's electricity rates, the average monthly bill for electricity, but not any other terms and conditions of those rates.

Report requirements

2 In a report to be provided to the minister under section 8 (4) of the Act, the authority must do all of the following:

(a) include a comparison with at least one public utility in each of at least fifteen other jurisdictions in North America, including all of the following:

(i) the provinces of Alberta, Quebec, Ontario and Manitoba;

(ii) the states of Washington, Oregon and California;

(b) compare the previous year's applicable rates for residential, commerical and industrial customers with similar rates of the public utilities referred to in paragraph (a);

(c) express the monetary comparisons in Canadian currency;

(d) provide the authority's previous 5 years of applicable rates.

DEPOSITED
JUN 28 2011
B.C. REG. 119/2011

JUN 28 2011
Date

Minister of Energy and Mines and Minister Responsible for Housing

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Clean Energy Act*, S.B.C. 2010, c. 22, s. 37 (f)

Other: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 125.1 (4) (c); M114/2009

June 9, 2011 Resub R/77/2011/27

page 1 of 1

10.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-7

1.10.1 In BC Hydro's understanding/interpretation, do retail customers (lines 16-22) include transmission connected consumers?

RESPONSE:

Yes, the term "retail customers" includes customers connected at transmission voltage.

11.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, pages 2-13 and 2-14

1.11.1 Does BC Hydro consider the principles underlying the Domestic Long-Term Sales Contract Regulation (as they pertain to the treatment and recovery of the costs of interconnecting to the BC Hydro transmission system and any system upgrades) to be of relevance to the Transmission Extension policy, which is the subject of 2015 RDA Module 2?

RESPONSE:

Pursuant to section 9 of the *CEA* the B.C. Government can direct BC Hydro to establish a program available to prescribed classes of customers on prescribed terms, including terms respecting price, for prescribed volumes of energy over prescribed periods as defined by Government.

Section 9 of the *CEA* was used by the B.C. Government to have BC Hydro develop rates for LNG facilities. As discussed in Workshop 1 (see Appendix C-1A, page 8 of 280) BC Hydro confirmed that for RDA Module 2 purposes, while specific LNG agreements are out of scope, the principles informing LNG ESAs are in scope taking into account any confidentiality requirements. BC Hydro also confirms that the principles informing LNG Load Interconnection Agreements would be in scope with the same caveat concerning confidentiality.

12.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, pages 1-20, 2-14 and 2-23

1.12.1 Please explain why "encouraging" energy efficiency was not adopted as one of the prioritized rate design criteria, particularly in light of the residential focus group feedback (page 2-23, lines 22-23).

RESPONSE:

BCOAPO refers to the two residential focus group sessions in the preamble to this IR:

- **At the first session in August 2014, participants ranked fairness and customer understanding and acceptance most highly (Exhibit B-1, page 2-22, lines 16 to 19); and**
- **At the second session in February 2015, participants ranked fairness above all other values at first, and then only after viewing rate designs did efficiency emerge as the most important value followed closely by fairness (Exhibit B-1, page 2-23, lines 20 to 23).**

In the context of the overall 2015 RDA, the reduced need for energy and capacity is one of the factors leading BC Hydro to prioritize customer understanding and acceptance and stable rates for customers over the Bonbright efficiency criterion. Please refer to BC Hydro's response to BCUC IR 1.6.1 for additional detail.

13.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: ExhibitB-1, page 2-16 (lines 9-16)

1.13.1 In BC Hydro's view, does the MEM Policy Letter require/obligate the Commission to exempt SFU and YVR from RS 1823 and other stepped rates?

RESPONSE:

In BC Hydro's view, the MEM Policy Letter does not require the Commission to continue with the exemption of SFU and YVR from RS 1823 and other stepped rates. BC Hydro stated its view at Exhibit B-1, page 2-16, lines 9 and 10: "[t]he Commission has jurisdiction under sections 58 to 61 of the *UCA* with regard to SFU and YVR".

It is BC Hydro's position that the Commission should place great weight on the MEM Policy Letter with respect to SFU and YVR and continuation of the exemption.

BC Hydro notes:

- **SFU and YVR oppose transfer from RS 1827 to RS 1823 or a stepped rate. Refer to: SFU's intervention application (Exhibit C7-1) and September 10, 2015 letter of support (Exhibit B-1, Appendix C-5E, pages 1 to 6 of 11); and to YVR's September 11, 2015 letter of support (Exhibit B-1, Appendix C-5E, pages 7 to 9 of 11); and**

- **No 2015 RDA stakeholder, including BCOAPO, advocated for the transfer of SFU and YVR to RS 1823 or a stepped rate. As part of Workshop 10, BCOAPO commented that it supports BC Hydro's proposal to continue with the existing RS 1827 for SFU and YVR; refer to the Workshop 10 consideration memo, Exhibit B-1, Appendix C-5B, pages 93 and 133 of 212.**

14.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, pages 2-22 to 2-23

1.14.1 Did the Residential Focus Group sessions canvas the participants as to any specific concerns they had regarding BC Hydro's residential rates?

RESPONSE:

BC Hydro received focus group participants' feedback on issues related to the RIB rate and three-step alternative rates (referred to as stepped rates for the purposes of this response). This feedback is found in Appendix C-3C of Exhibit B-1.

Some of the issues raised include:

- **Participants were mixed on whether or not the inclining rate encouraged them to conserve;**
- **Most participants preferred a two-step rate over a three-step rate;**
- **It is difficult to know when their consumption reached the next steps and that text or email alerts would be helpful; and**
- **Concern that the inclining rates unfairly promote lower rates for smaller homes with fewer occupants and do not encourage conservation for detached larger family homes.**

14.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, pages 2-22 to 2-23

1.14.1 Did the Residential Focus Group sessions canvas the participants as to any specific concerns they had regarding BC Hydro's residential rates?

1.14.1.1 If yes, what feedback was received?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.14.1.

15.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-30 (lines 19-20)

1.15.1 What were the other three policy objectives that "grounded" BC Hydro's 1991 RDA?

RESPONSE:

In addition to "no customer bills should increase by more than 10 per cent", the other three policy objectives are listed at page 13 of the Commission's 1991 RDA Decision[1] as:

- **"[T]he current allocation of revenues among customers is acceptable". This is a COS issue and as such is encompassed by the Bonbright fairness criterion;**
- **"[T]he current [Residential] declining block rate structure is inappropriate" (1991 RDA Decision, page 16). This policy objective is not relevant to the 2015 RDA. The RIB rate has been in place since October 2008. Alternatives to the RIB rate are canvassed in section 5.2.4 of Exhibit B-1; BC Hydro examined alternatives suggested by stakeholders and canvassed as part of the 2008 RIB rate review process. No 2015 RDA stakeholder suggested that BC Hydro examine a declining block rate for Residential customers;**
- **"[N]o customer bill should decline". This policy objective was expanded upon to mean that there should not be "a substantial decline in rates to a particular customer class or large groups within a class" (1991 RDA Decision, page 18). It is not clear to BC Hydro what "substantial decline" means. In any event, in BC Hydro's view this policy objective is no longer relevant to the 2015 RDA as it was expressly tied to Special Direction No. 3, which was revoked by OIC 1684/1992 (refer to footnote 65 of Exhibit B-1, page 2-30).**

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[1] **Cite is found at footnote 64 of Exhibit B-1, page 2-30; copy available at http://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/112914/index.do.**

15.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-30 (lines 19-20)

1.15.2 Please discuss the extent to which each of the four policy objectives are applicable in the context of the 2015 RDA.

RESPONSE:

The 10 per cent bill impact test remains applicable to 2015 RDA Module 1; refer to Exhibit B-1, section 2.4.1.1.

With respect to the other three policy objectives, please refer to BC Hydro's response to BCOAPO IR 1.15.1.

16.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, pages 2-32 through 2-34

1.16.1 Have any of the Government responses set out in Table 2-2 been superseded or altered as result of subsequent government policy statements, regulations or legislation?

RESPONSE:

BC Hydro included in Table 2-2 of Exhibit B-1 and the accompanying text at page 2-34, lines 1 to 4 references to all subsequent, relevant legislation, regulations and B.C. Government policy statements as part of the 'BC Hydro Note'. This includes references to sections in Exhibit B-1 which discuss such legislation, regulations and B.C. Government policy statements. An example concerns Heritage Contract Recommendations No. 8 to No. 15, in which the 'BC Hydro Note' refers to those parts of 2015 RDA Chapter 7 outlining how subsection 3(1) of Direction No. 7 confines the Commission's jurisdiction with respect to various Transmission Service rates such as RS 1823.

16.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, pages 2-32 through 2-34

1.16.1 Have any of the Government responses set out in Table 2-2 been superseded or altered as result of subsequent government policy statements, regulations or legislation?

1.16.1.1 If yes, please indicate what the revised government response/position is.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.16.1.

17.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, pages 2-37 to 2-39

1.17.1 Were there policy objectives that "grounded" BC Hydro's 2007 RDA?

RESPONSE:

Yes; please refer to BC Hydro's response to BCUC IR 1.6.1.

17.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, pages 2-37 to 2-39

1.17.1 Were there policy objectives that "grounded" BC Hydro's 2007 RDA?

1.17.1.1 If yes, what were they, and are they still applicable in the context of the current 2015 RDA?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.6.1.

18.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-44

1.18.1 While BC Hydro's current load curtailment program is not viewed as a "rate" or a "service", would it not be possible for BC Hydro to design a rate for non-firm service (i.e., service that could be curtailed under certain circumstances) for transmission customers and for which the customers would pay a different rate and that would qualify as rate and service under Section 1?

RESPONSE:

In BC Hydro's view, this question is moot given that BC Hydro's industrial load curtailment program launched on August 19, 2015; refer to Exhibit B-1, page 2-44. In addition, no 2015 RDA stakeholder opposed BC Hydro's decision to structure industrial load curtailment as a DSM program. BC Hydro's reasons for doing so are summarized at Exhibit B-1, page 2-44. BC Hydro notes that BCOAPO did not raise this issue either at Workshop 5 or Workshop 10, at which the industrial load curtailment program was discussed. BCOAPO's comments concerned supporting BC Hydro's proposed pilot approach to the program, and the value of capacity. Refer to the Workshop 5 consideration memo, Exhibit B-1, Appendix C-5A, pages 173 to 174 of 292.

To be responsive, BC Hydro notes that as set out in Table 4 of the Workshop 5 consideration memo (Exhibit B-1, Appendix C-5A, page 99 of 292), some jurisdictions offer load curtailment programs while others offer interruptible rates for industrial customers.

18.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-44

1.18.1 While BC Hydro's current load curtailment program is not viewed as a "rate" or a "service", would it not be possible for BC Hydro to design a rate for non-firm service (i.e., service that could be curtailed under certain circumstances) for transmission customers and for which the customers would pay a different rate and that would qualify as rate and service under Section 1?

1.18.1.1 If not, please explain why?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.18.1.

18.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-44

1.18.1 While BC Hydro's current load curtailment program is not viewed as a "rate" or a "service", would it not be possible for BC Hydro to design a rate for non-firm service (i.e., service that could be curtailed under certain circumstances) for transmission customers and for which the customers would pay a different rate and that would qualify as rate and service under Section 1?

1.18.1.2 If not, please explain how such an approach would differ, in principle, from the Residential E-Plus Rate.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.18.1.

19.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-46

BC Hydro notes that the standard economic technique used to determine LRMC is to calculate the minimum present-day view of the cost of meeting a permanent increment (or decrement) of demand.

1.19.1 It is noted that BC Hydro's calculation of LRMC is based on the cost of meeting an increment in demand. Would the calculation and resulting LRMC differ if the approach was based on the cost savings from a decrement in demand?

RESPONSE:

No. In the 2013 IRP, BC Hydro considered both demand-side as well as supply-side resources in determining the energy LRMC range.

19.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-46

BC Hydro notes that the standard economic technique used to determine LRMC is to calculate the minimum present-day view of the cost of meeting a permanent increment (or decrement) of demand.

1.19.2 Will these resources (i.e. those listed at lines 22-25) also be sufficient to meet BC Hydro's capacity needs over the next 10 years?

RESPONSE:

No. Capacity contributions from DSM savings and IPP EPA renewals will not be sufficient to meet BC Hydro's capacity needs over the next ten years before Site C's F2025 ISD. As shown in the Base Resource Plan of the approved 2013 IRP, BC Hydro expects to acquire additional capacity resources in the North Coast.

19.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-46

BC Hydro notes that the standard economic technique used to determine LRMC is to calculate the minimum present-day view of the cost of meeting a permanent increment (or decrement) of demand.

1.19.2 Will these resources (i.e. those listed at lines 22-25) also be sufficient to meet BC Hydro's capacity needs over the next 10 years?

1.19.2.1 If not, what other resources will need to be relied on?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.19.2.

20.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-48, lines 1-10

1.20.1 Given that Site C comes into service in F2025, why is it not included in the list of resources (lines 6-10) being used to meet expected energy future energy needs?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.9.1.

21.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-48, lines 18-27

1.21.1 Why are the RIB rate and RS1823 considered "future DSM initiatives" (per lines 26-27) when they are already in place?

RESPONSE:

The RIB rate and RS 1823 are considered "future DSM initiatives" because: 1) they meet the definition of "demand-side measure" set out in section 1 of the *CEA*; 2) these future DSM initiatives are not committed resources[1] because material regularly approvals have not yet been secured (e.g., through the 2015 RDA); and 3) their future energy savings are included in the DSM Plan that formed Recommended Action 1 in the 2013 IRP.

[1] **BC Hydro defines committed resources as resources for which material regulatory and BC Hydro executive approvals have been secured; refer, for example, to footnote 6 in Chapter 1 of the 2013 IRP; https://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/november-2013-irp.html.**

21.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-48, lines 18-27

1.21.2 What does the "Load Forecast Before DSM" shown in Figure 2-1 assume with respect to the existence and the impact of the Residential RIB rate and RS1823 in F2017 and beyond?

RESPONSE:

The "Load Forecast Before DSM" shown in Figure 2-1 of Exhibit B-1 does not reflect any incremental conservation savings from rate structures (i.e., RIB rate, RS 1823, LGS, MGS) from F2012 onwards. (The December 2012 load forecast in the 2013 approved IRP was calibrated with historical sales up to F2011, this is why F2012 is stated).

Please also refer to BC Hydro's response to BCOAPO IR 1.21.1.

22.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-49 to 2-50

Given the 2015 RDA also discusses the treatment of capacity long-run marginal costs in determining the LRMC to be used for rate making it is necessary to fully understand the basis for the energy LRMC proposed by BC Hydro.

1.22.1 Please explain more fully what is meant by "net TRC" in the context of DSM programs. In particular, please clarify whether the participant and utility costs, which according to Footnote 95 form the basis for the overall TRC (economic cost) of DSM initiatives, have been reduced by netting out: a) generation capacity benefits, b) transmission capacity benefits, c) distribution capacity benefits, d) non-energy benefits, and e) natural gas savings benefits.

RESPONSE:

The gross levelized TRC for DSM is expressed as $/MWh, where the numerator reflects the cost needed to acquire the energy savings – these would include utility program costs, partner costs and the project cost (sum of the contributions from the utility and participant); and the denominator reflects the quantity of energy savings.

However, in most cases, DSM activities also generate additional benefits besides energy savings: generation capacity benefits, transmission and distribution capacity savings, non-energy benefits and other fuel savings. Within the net levelized TRC cost calculation, these benefits are netted off from the cost in the numerator.

22.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-49 to 2-50

Given the 2015 RDA also discusses the treatment of capacity long-run marginal costs in determining the LRMC to be used for rate making it is necessary to fully understand the basis for the energy LRMC proposed by BC Hydro.

1.22.2 What was the basis for the generation capacity benefit that was netted from the TRCs for the various DSM programs set out in Table 9-7 of the 2013 IRP?

RESPONSE:

The generation capacity benefit for the F2017 to F2032 period is based on the UCC of Rev 6.

22.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-49 to 2-50

Given the 2015 RDA also discusses the treatment of capacity long-run marginal costs in determining the LRMC to be used for rate making it is necessary to fully understand the basis for the energy LRMC proposed by BC Hydro.

1.22.2 What was the basis for the generation capacity benefit that was netted from the TRCs for the various DSM programs set out in Table 9-7 of the 2013 IRP?

1.22.2.1 If it differs from the UCC of Revelstoke Unit 6, please explain why.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.22.2.

22.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-49 to 2-50

Given the 2015 RDA also discusses the treatment of capacity long-run marginal costs in determining the LRMC to be used for rate making it is necessary to fully understand the basis for the energy LRMC proposed by BC Hydro.

1.22.2 What was the basis for the generation capacity benefit that was netted from the TRCs for the various DSM programs set out in Table 9-7 of the 2013 IRP?

1.22.2.2 If it differs from the UCC for Revelstoke Unit 6, please recalculate the net TRC values for each of the DSM programs using Revelstoke Unit 6 as the basis for the generation capacity benefit.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.22.2.

22.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-49 to 2-50

Given the 2015 RDA also discusses the treatment of capacity long-run marginal costs in determining the LRMC to be used for rate making it is necessary to fully understand the basis for the energy LRMC proposed by BC Hydro.

1.22.3 For each DSM program listed in Table 9-7 from the 2013 IRP please indicate the value (in both $/kW and $/kWh using the same F2013$ as Table 9-7)) attributed to each of the generation, transmission and distribution capacity benefits.

RESPONSE:

The table below shows the calculation of the net levelized TRC in $/MWh. It starts with gross levelized cost (program costs, project costs and partner costs) and nets out any additional benefits (shown in the table as negative levelized costs – non-energy benefits, natural gas benefits, generation capacity benefits and T&D capacity benefits) to arrive at a net levelized TRC in $/MWh.

DSM Programs (sorted by net TRC)	Gross TRC ($/MWh)	Non-Elec. Benefits ($/MWh)	Natural Gas Benefits ($/MWh)	Generation Capacity Benefits ($/MWh)	T&D Capacity Benefits ($/MWh)	Net TRC ($/MWh)
Behaviour	23	0	0	-14	-3	6
Load Displacement – Ind	36	0	0	-8	-2	27
Power Smart Partner – Transmission	45	0	0	-8	-2	36
Load Displacement - Res	42	0	0	0	0	42
Refrigerator Buy-back	43	0	8	-7	-1	43
Residential Rebate	61	0	1	-14	-3	46
Power Smart Partner – Distribution	62	0	0	-9	-2	51
Power Smart Partner – Com	66	0	-2	-10	-2	52
Product Incentive	66	0	0	-9	-2	55
New Construction	94	-9	-14	-9	-2	60

DSM Programs (sorted by net TRC)	Gross TRC ($/MWh)	Non-Elec. Benefits ($/MWh)	Natural Gas Benefits ($/MWh)	Generation Capacity Benefits ($/MWh)	T&D Capacity Benefits ($/MWh)	Net TRC ($/MWh)
Load Displacement – Com	89	-9	0	-9	-2	69
Lead by Example	85	0	-5	-7	-1	71
Renovation Rebate	93	0	0	-14	-3	77
Low Income	119	-28	5	-7	-1	88
New Home	130	0	0	-14	-3	113

BC Hydro does not believe it is appropriate to show the levelized cost for DSM programs in the units of $/kW-yr. The reason is that the DSM programs listed above are energy-focused initiatives that also produce associated capacity savings. Portraying the levelized cost of energy-focused initiatives with a capacity metric ($/kW-yr) may lead to inappropriate comparisons.

22.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-49 to 2-50

Given the 2015 RDA also discusses the treatment of capacity long-run marginal costs in determining the LRMC to be used for rate making it is necessary to fully understand the basis for the energy LRMC proposed by BC Hydro.

1.22.4 With respect to the net TRC values presented in Table 9-7 (from the 2013 IRP) please indicate: a) what period the values are levelized/calculated over, and b) whether the values represent the real LRMC values (in F2013$).

RESPONSE:

The results are based on an analysis over a 30-year period (F2014-F2043) – a 20-year investment period (F2014 to F2033) with an additional 10 years to account for benefits from savings persistence.

The values are shown in F2013$.

22.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-49 to 2-50

Given the 2015 RDA also discusses the treatment of capacity long-run marginal costs in determining the LRMC to be used for rate making it is necessary to fully understand the basis for the energy LRMC proposed by BC Hydro.

1.22.5 Please re-state the DSM options net TRC costs as shown in Table 9-7 in F2016$ so as to make them comparable with the EPA renewal costs cited on page 2-50.

RESPONSE:

The following table shows the range of net TRC of DSM programs shown in Table 9-7 of the 2013 IRP re-instated in $F2016.

DSM Programs (sorted by net TRC)	***Net TRC (F2013$/MWh)***	***Net TRC (F2016$/MWh)***
Behaviour	6	7
Load Displacement - Ind	27	28
Power Smart Partner - Transmission	36	37
Load Displacement - Res	42	44
Refrigerator Buy-back	43	44
Residential Rebate	46	47
Power Smart Partner - Distribution	51	53
Power Smart Partner - Com	52	54
Product Incentive	55	56
New Construction	60	61
Load Displacement - Com	69	71
Lead by Example	71	73
Renovation Rebate	77	79
Low Income	88	91
New Home	113	117

BC Hydro notes that net TRC of DSM programs is not directly comparable to the $70/MWh and $95/MWh values which are based on BC Hydro's opportunity cost, given, among other things, that these values include capacity credits where applicable and non-firm energy values. With respect to the $70/MWh and $95/MWh values, please refer to BC Hydro's response to CEBC IR 1.3.1 for more details.

23.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-50, lines 1-6

1.23.1 Please clarify what is meant when the Application states that DSM Option 3 would "entail no changes to BC Hydro's rate structures."

RESPONSE:

DSM Option 3 in the 2013 IRP was constructed using the same 'status quo' assumptions around rate structures as used in the DSM Plan that formed Recommended Action 1. The existing RIB, LGS, MGS and RS 1823 rate structures were assumed to stay intact over the planning period.

23.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-50, lines 1-6

1.23.2 The wording at lines 1-4 suggests that, as compared to DSM Option 3, Recommended Action 1 in the 2013 IRP does include "changes to BC Hydro's rate structure". Please confirm whether or not this is the case.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.23.1.

23.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-50, lines 1-6

1.23.2 The wording at lines 1-4 suggests that, as compared to DSM Option 3, Recommended Action 1 in the 2013 IRP does include "changes to BC Hydro's rate structure". Please confirm whether or not this is the case.

1.23.2.1 If yes, specifically what changes to BC Hydro's rate structures were envisioned in Recommended Action 1 on DSM.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.23.1.

24.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-54

1.24.1 Given the requirement of the Clean Energy Act, Section 2(c), is there a limit to the amount of natural gas-fired simple-cycle gas turbine generators that could be installed to meet generation capacity requirements?

RESPONSE:

The amount of energy generated from existing non-clean/non-renewable generation including any new SCGTs would be limited per British Columbia's energy objective 2(c). This is because any generation from natural gas-fired SCGTs would not be considered "clean or renewable resource" as defined in section 1 of the *CEA* and the <u>Clean or Renewable Resource Regulation</u>.

24.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-54

1.24.1 Given the requirement of the Clean Energy Act, Section 2(c), is there a limit to the amount of natural gas-fired simple-cycle gas turbine generators that could be installed to meet generation capacity requirements?

1.24.1.1 If yes, how does this affect the use of SCGTs are a benchmark for capacity long-run marginal cost?

RESPONSE:

The limitation on the amount of SCGTs that can be used to meet generation capacity requirements does not affect the use of SCGTs as benchmark for capacity LRMC because there is room within the limits identified in BC Hydro's response to BCOAPO IR 1.24.1.

25.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-55

1.25.1 Is it BC Hydro's view that the LRMC used for rate making should not: a) include avoided transmission costs when considering RS 1823, and b) should not include avoided transmission and distribution costs when considering the RIB rate?

RESPONSE:

a) Yes, it is BC Hydro's view that the LRMC used for rate-making should not include avoided transmission costs when considering RS 1823. This view is based on the following Commission decisions:

- **Commission Order No. G-79-05, approving a NSA concerning BC Hydro's 2005 TSR Application. Participants to the NSA generally agreed that setting the RS 1823 Tier 2 price on the basis of the weighted average price of energy from the last province-wide Call For Tender (CFT) represents the long-term opportunity cost of new supply (as required by Recommendation No. 8 in the Heritage Contract Report);**

- **Commission Order No. G-97-08, approving BC Hydro's 2008 TSR Re-Pricing Application. That Application proposed that the RS 1823 Tier 2 rate be set equal to the levelized weight-average plant gate price of energy resulting from the F2006 CFT. Footnote 92 of Exhibit B-1 at page 2-47 provides the definition of plant gate prices as excluding any incremental delivery costs of either transmission or distribution.**

b) Yes, it is BC Hydro's view that the LRMC used for rate-making should not include avoided transmission and distribution costs when considering the RIB rate. This view is based on the following Commission decision:

- **In the 2008 RIB Reasons for Decision accompanying Commission Order No. G-124-08, the Commission determined that the RIB rate structure is a conservation rate intended to show existing customers the cost of new supply and to offer an incentive to reduce consumption, and in these circumstances it is incorrect to show the existing customer the incremental cost of transmission and distribution.**

25.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-55

1.25.2 What are the avoided transmission and distribution costs associated with Residential service? Please provide the F2013$ values both in $/kW and in $/kWh based on the Residential load profile?

RESPONSE:

BC Hydro does not have an estimate of the avoided transmission and distribution costs of Residential service because a detailed marginal COS study has not been undertaken or completed for the reasons discussed in section 3.4 of Exhibit B-1.

25.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-55

1.25.3 What are the avoided transmission costs for RS 1823 customers? Please provide the F2013$ values in both $/kW and $/kWh based on the load profile for transmission service customers.

RESPONSE:

Please refer to BC Hydro's response to BCOAP IR 1.25.2.

25.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, page 2-55

1.25.4 Please provide revised versions of Tables 2-5 and 2-6 with an additional column that sets out the value for the Upper End of the Energy LRMC plus the Rev 6 UCC, adjusting for losses as necessary.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.11.2.

26.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, pages 2-59 & 2-66

1.26.1 Please clarify whether in applying the 10% impact test, BC Hydro looks at the impact on: a) the most adversely affected customer in the entire Residential class, or b) the most adversely affected customer in its representative sample of 10,000.

RESPONSE:

For the purpose of rate modelling for Exhibit B-1 where the 10 per cent bill impact test is a modelling constraint, BC Hydro generally uses the representative sample of 10,000 to determine the most adversely affected customer (e.g., three step option A).

Note that none of the proposed Residential, LGS or MGS rate designs have the 10 per cent impact test as a modelling constraint.

26.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, pages 2-59 & 2-66

1.26.1 Please clarify whether in applying the 10% impact test, BC Hydro looks at the impact on: a) the most adversely affected customer in the entire Residential class, or b) the most adversely affected customer in its representative sample of 10,000.

1.26.1.1 If response is (b), please indicate (based on the last 12 months of available billing data) how many Residential customers use: i) less electricity than the customer in the representative sample with the lowest use and ii) more electricity than the customer in the representative sample with the highest use.

RESPONSE:

Based on F2015 data:

i) No customer accounts consumed less than zero kWh (no use), which is also the minimum in the representative sample; and

ii) 28 customer accounts.

26.0 CHAPTER 2 STAKEHOLDER ENGAGEMENT AND RATE DESIGN EVALUATION METHODOLOGY

Reference: Exhibit B-1, pages 2-59 & 2-66

1.26.1 Please clarify whether in applying the 10% impact test, BC Hydro looks at the impact on: a) the most adversely affected customer in the entire Residential class, or b) the most adversely affected customer in its representative sample of 10,000.

1.26.1.2 If response is (b), please indicate (based on the last 12 months of available billing data): i) what average monthly usage is for the lowest use Residential customer overall vs. the lowest use customer in the representative sample, and ii) what the average monthly usage is for the highest use Residential customer overall vs. the highest use customer in the representative sample.

RESPONSE:

i) The lowest use customer for both the representative sample and the population is zero kWh (no use); and

ii) 1,375,920 kWh.

27.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-1 & 3-37 and Appendix E, COSS – Schedule 4.1

1.27.1 With respect to Table 3-7, please provide a revised version that sets out for each Rate Class:

(a) The energy, demand and customer costs (in dollars) allocated per COSS Schedule 4.1;

(b) A breakdown of "customer costs" separating out that portion of the distribution system's substations, primary system, transformers and secondary system that has been classified as "customer-related" and allocated to the rate classes;

(c) A breakdown of "demand costs" separating out that portion that is allocated based on 4CP vs. NCP;

(D) The F2016 customer count, billed energy and billing demand (where applicable) determinants by class as used in establishing the forecast revenues by customer class in the COSS per Appendix E;

(e) The ratio of: i) allocated energy costs per billing kWh (Note- for classes that are not billed using demand also include the demand costs in this calculation), ii) allocated demand costs per billing kW (for applicable classes) broken down per point (c), and iii) allocated customer costs broken down per point (b) per customer per month.

RESPONSE:

(a) The requested information is provided in Schedule 4.1 of the F2016 COS study.

(b) F2016 customer-related costs by function and allocator ($ million)

Function	Distribution Customer	Distribution Street Lighting	Distribution Transformer	Distribution Metering	Customer Care
Classification	Customer	Customer	Customer (50%)	Customer	Customer
Allocator	Customer Count	Direct Assigned	Direct Assigned	Metering	Customer Count/ Revenue
COS Source Schedule	3.2	3.2	3.2	3.2	3.3
Residential	66.8	0.0	46.7	90.6	69.2
SGS	6.9	0.0	12.0	18.7	7.6
MGS	0.7	0.0	7.7	5.7	2.1
LGS	0.2	0.0	3.9	2.0	2.0
Irrigation	0.1	0.0	0.4	0.4	0.1
Street Lighting	0.4	4.6	0.7	0.0	0.8
Transmission	0.0	0.0	0.0	0.0	1.7
Total	75.2	4.6	71.3	117.5	83.4

(c) F2016 demand-related costs by function and allocator ($ million)

Function	Generation	Transmission	Distribution Primary	Distribution Secondary	Distribution Transformer
Classification	Demand	Demand	Demand	Demand	Demand (50%)
Allocator	4CP	4CP	NCP	NCP w/o Primary	Direct Assigned
COS Source Schedule	3.0	3.1	3.2	3.2	3.2
Residential	282.4	364.3	331.1	36.0	46.7
SGS	44.5	57.4	62.1	6.8	12.0
MGS	39.7	51.2	50.1	13.9	7.7
LGS	113.4	146.3	135.2	4.3	3.9
Irrigation	0.0	0.0	2.5	0.3	0.4
Street Lighting	3.7	4.7	3.9	0.4	0.7
Transmission	132.3	170.6	0.0	0.0	0.0
Total	616.0	794.4	585.0	61.6	71.3

(d) The F2016 customer count, billed energy and billing demand

Determinant	Billed Energy (GWh)	Billing Demand	Customer Count
Residential	18,743	N/A	1,766,045
SGS	3,703	N/A	182,647
MGS	3,730	11,212,979 kW	18,639
LGS	10,913	26,322,559 kW	6,466
Irrigation	79	N/A	3,534
Street Lighting	230	N/A	9,996
Transmission	16,049	27,803,895 kVA	304
Total	53,448		1,987,630

(e) The ratio of:

(i) allocated energy (and demand) costs per billing kWh

	Billed Energy (GWh)	Allocated Energy Cost	Allocated Demand Cost	Cost per kWh (¢)
Residential	18,743	708.4	1,060.5	9.44
SGS	3,703	140.0	182.7	8.71
MGS	3,730	129.2	-	3.78
LGS	10,913	417.8	-	3.72
Irrigation	79	3.0	0.9	7.79
Street Lighting	230	8.7	6.5	9.62
Transmission	16,049	572.3		3.57

ii) allocated demand costs per billing kW (for applicable classes) broken down per point (c)

Function	Generation $/kW or $/kVA	Transmission $/kW or $/kVA	Distribution Primary $/kW or $/kVA	Distribution Secondary $/kW or $/kVA	Distribution Transformer $/kW or $/kVA
Residential	-	-	-	-	-
SGS	-	-	-	-	-
MGS	3.54	4.57	4.46	1.24	0.68
LGS	4.31	5.56	5.14	0.16	0.15
Irrigation	-	-	-	-	-
Street Lighting	-	-	-	-	-
Transmission	4.76	6.14	0.00	0.00	0.00

iii) allocated customer costs broken down per point (b) per customer per month

Function	Distribution Customer ($/month)	Distribution Street Lighting ($/month)	Distribution Transformer ($/month)	Distribution Metering ($/month)	Customer Care ($/month)
Residential	3.15	-	2.21	4.28	3.26
SGS	0.33	-	0.57	0.88	0.36
MGS	0.03	-	0.36	0.27	0.10
LGS	0.01	-	0.18	0.09	0.10
Irrigation	0.01	-	0.02	0.02	0.00
Street Lighting	0.02	0.22	0.03	-	0.04
Transmission	0.00	-	-	-	0.08

28.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-6 (lines 20-22) and pages 3-7 to 3-11

1.28.1 The Application makes note of the Commission's decision regarding FortisBC's 2009 Rate Design/COS Application. Please indicate how the COS Methodology as proposed by BC Hydro for the 2015 RDA aligns with the Commission's directives in the FortisBC decision regarding COS methodology.

RESPONSE:

The following table compares BC Hydro's F2016 COS methodology with BCUC directives found on page 118 of the Commission's Decision in the FortisBC Inc. 2009 Rate design and Cost of Service Analysis proceeding.

	BC Hydro's F2016 COS methodology	Cost of Service related directives to FortisBC
1	BC Hydro has a single rate class for all transmission voltage customers including wholesale customers such as New West and FortisBC.	The Commission Panel agrees with each of BCMEU's arguments in favour of a single class and determines that the Wholesale customers (other than Nelson which will remain its separate class) can be considered to be a single class for COSA purposes. The Commission Panel directs FortisBC to re-run the COSA on this basis.
3	Load profiles for each customer class are created using the load data described in section 3.5.4 of Exhibit B-1. These profiles are then analyzed to determine 4CP and NCP allocations for each class.	The Commission Panel accepts FortisBC's load data for COSA purposes, other than for its Irrigation customers as discussed below. Page 118 of the decision notes that "the contribution to the system peak of each customer class is determined either from actual metered customer load data, or from estimates based on metered consumption and available information."
4	The load profiles are used to estimate coincident peak load by rate class, which in turn are used in 4CP allocation. Contract demands are not used.	The Commission Panel accepts the use of actual coincident peak demands for COSA purposes, and directs FortisBC to re-run the COSA, using actual coincident peak demands for all customers rather than contract demands (or demand limits).
5	BC Hydro uses a 4CP allocation for all generation and transmission demand-related costs. This is based on the four winter months while FortisBC's 2CP calculation is an average of its summer and winter peaks.	The Commission Panel accepts FortisBC's use of the 2CP method for allocating the demand portion of production costs as well as for allocating transmission costs.

	BC Hydro's F2016 COS methodology	Cost of Service related directives to FortisBC
6	**BC Hydro uses an hourly load profile for the irrigation rate class to allocate demand costs. No load factor calculations are performed in the F2016 COS study for allocation purposes.**	**The Commission Panel considers that there is no basis for using different load factors in different months during the irrigation season, and that a single load factor should be applied. As for load factors in the non-irrigation season, the Commission Panel considers that the RS 20 load factors should be used in those months. Accordingly, the Commission Panel directs FortisBC to re-run the COSA using the following assumption:** • **a 70 per cent load factor for the irrigation season (being the load factor for June, July and August) and the Small General Service load factor for the remaining months.**
7	**BC Hydro does not use the minimum system method for distribution classification.**	**The Commission Panel accepts FortisBC's proposed classification of distribution system costs related to poles, conductors and transformers based on the minimum system method.**
8	**Since BC Hydro does not use the minimum system method for distribution classification, no Peak Load Carrying Capability (PLCC)adjustment is used.**	**The Commission Panel also accepts that the PLCC adjustment compensates for changes in the minimum size and shifts the costs associated with the increased capacity of the minimum system to those customers having a higher than the average 1kW demand on the system. The Commission Panel therefore finds the use of the PLCC adjustment to the results of the minimum system method an appropriate refinement to the 1992 minimum system study.**

28.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-6 (lines 20-22) and pages 3-7 to 3-11

1.28.2 Please contrast how FortisBC's COS methodology (as approved by the BCUC) contrasts with BC Hydro's proposals with respect to the key issue areas noted at page 3-7 (lines 11-13).

RESPONSE:

BC Hydro and FortisBC's cost of service methodologies are compared in the table below.

	BC Hydro (F2016 COS Study)	FortisBC
Heritage hydro classification	Load factor methodology adjusted for IPP supply (55% energy, 45% demand)	FortisBC's classification methodology is described on page 17, Appendix A, Exhibit B-1, FortisBC 2009 Rate Design Application found at: http://www.bcuc.com/Documents/Proceedings/2009/DOC_23627_B-1_FortisBC%202009%20Rate%20Design%20Application.pdf The Four Kootenay Plants are classified using Generation rate base (about 80% energy, 20% demand)
IPP classification	Value of capacity approach (93% energy, 7% demand)	Refer to FortisBC's treatment of the Brilliant Energy plant on page 22, Appendix A, Exhibit B-1, FortisBC 200 Rate Design Application found at: http://www.bcuc.com/Documents/Proceedings/2009/DOC_23627_B-1_FortisBC%202009%20Rate%20Design%20Application.pdf. The Brilliant plant is classified about 80% energy, 20% demand
Distribution sub-functionalization	Distribution rate base used	Distribution rate base used
Distribution classification	Substations, primary system (100% demand) Transformers (50% demand, 50% customer) Secondary (100% demand) Services (100% customer) Meters (100% customer)	Minimum System method used. Refer to pages 23 to 24 of Appendix A from FortisBC's application. Schedule 3.1 of Appendix A shows different classification factors for different components of the distribution system.
Distribution allocation	NCP for demand-related costs Number of customers for services Weighted customer allocated for meters	Numerous distribution allocators used.

29.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-11 and 3-36

1.29.1 Please provide the R/C Ratios that would result if the methodology approved in the 2007 RDA Decision was applied using the F2016 costs and updated load profiles/allocators as discussed on page 3-11, lines 9-18.

RESPONSE:

Please refer to BC Hydro's response to Commission IR 1.17.1 and the "Base Forecast" in BC Hydro's response to AMPC IR 1.3.11.

29.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-11 and 3-36

1.29.2 Using the COSS results per part (1), please provide a schedule that sets out for each Rate Class:

(a) The energy, demand and customer costs (in dollars) allocated;
(b) A breakdown of "customer costs" separating out that portion of the distribution system's substations, primary system, transformers and secondary system that has been classified as "customer-related" and allocated to the class;
(c) A breakdown of "demand costs" separating out that portion that is allocated based on 4CP vs. NCP;
(d) The F2016 customer count, billed energy and billing demand (where applicable) determinants by class as used in establishing the forecast revenues by customer class in the 2015 RDA; and
(e) The ratio of: i) allocated energy costs per billing kWh (Note- for classes that are not billed using demand also include the demand costs in this calculation), ii) allocated demand costs per billing kW (for applicable classes) broken down per (c), and iii) allocated customer costs broken down per point (b) per customer per month.

RESPONSE:

(a) F2016 forecast COS results using 2007 RDA Decision methodology for functionalization and classification and F2016 COS methodology for allocation.

Rate Class	Energy	Demand	Customer
Residential	658.3	1,107.3	304.5
SGS	130.0	189.8	50.5
MGS	120.1	168.7	17.0
LGS	388.2	422.7	7.8
Irrigation	2.8	3.1	1.1
Street Lighting	8.1	14.0	6.4
Transmission	531.8	326.3	1.0
Total	1,839.3	2,232.1	388.3

(b) F2016 customer-related costs by function and allocator, using prescribed methodology

Function	Distribution Customer	Distribution Street Lighting	Distribution Transformer	Distribution Metering	Customer Care
Classification	Customer	Customer	Customer (50%)	Customer	Customer
Allocator	Customer Count	Direct Assigned	Direct Assigned	Metering	Customer Count/ Revenue
COS Source Schedule	3.2	3.2	3.2	3.2	3.3
Residential	103.4	0.0	45.2	114.6	41.4
SGS	10.7	0.0	11.6	23.7	4.5
MGS	1.1	0.0	7.4	7.3	1.2
LGS	0.4	0.0	3.7	2.5	1.2
Irrigation	0.2	0.0	0.4	0.5	0.0
Street Lighting	0.6	4.6	0.7	0.00	0.5
Transmission	0.0	0.0	-	0.00	1.0
Total	116.4	4.6	69.0	148.5	49.9

(c) F2016 demand-related costs by function and allocator, using prescribed methodology.

Function	Generation	Transmission	Distribution Primary	Distribution Secondary	Distribution Transformer	Customer Care
Classification	Demand	Demand	Demand	Demand	Demand (50%)	Demand
Allocator	4CP	4CP	NCP	NCP w/o Primary	Direct Assigned	NCP
COS Source Schedule	3.0	3.1	3.2	3.2	3.2	3.3
Residential	345.74	350.97	278.21	34.79	45.2	52.42
SGS	54.44	55.26	52.19	6.53	11.6	9.83
MGS	48.59	49.32	42.06	13.43	7.4	7.92
LGS	138.87	140.97	113.60	4.15	3.7	21.41
Irrigation	0.00	0.00	2.11	0.26	0.4	0.40
Street Lighting	4.47	4.54	3.29	0.41	0.7	0.62
Transmission	161.95	164.40	0.00	0.00	-	0.00
Total	754.05	765.45	491.46	59.57	69.0	92.61

(d) Please refer to the response to BCOAPO IR 1.27.1 (d).

(e) The ratio of:

(i) allocated energy (and demand) costs per billing kWh

	Billed Energy (GWh)	Allocated Energy Cost	Allocated Demand Cost (for Rate Classes without Demand Charge)	Cost per kWh
Residential	18,743	658.3	1,095.6	9.36
SGS	3,703	130.0	182.8	8.45
MGS	3,730	120.1	-	3.51
LGS	10,913	388.2	-	3.46
Irrigation	79	2.8	3.1	7.42
Street Lighting	230	8.1	15.5	10.25
Transmission	16,049	531.8	-	3.31

ii) allocated demand costs per billing kW (for applicable classes) broken down per point (c)

Function	Generation $/kW or $/kVA	Transmission $/kW or $/kVA	Distribution Primary $/kW or $/kVA	Distribution Secondary $/kW or $/kVA	Distribution Transformer $/kW or $/kVA
Residential	-	-	-	-	-
SGS	-	-	-	-	-
MGS	4.46	4.53	4.55	1.20	-
LGS	5.33	5.41	5.35	0.16	-
Irrigation	-	-	-	-	-
Street Lighting	-	-	-	-	-
Transmission	5.54	5.63	-	-	-

iii) allocated customer costs broken down per point (b) per customer per month

Function	Distribution Customer ($/month)	Distribution Street Lighting ($/month)	Distribution Transformer ($/month)	Distribution Metering ($/month)	Customer Care ($/month)
Residential	4.88	-	2.13	5.41	1.95
SGS	0.50	-	0.55	1.12	0.21
MGS	0.05	-	0.35	0.34	0.06
LGS	0.02	-	0.18	0.12	0.06
Irrigation	0.01	-	0.02	0.02	0.00
Street Lighting	0.03	0.22	0.03	-	0.02
Transmission	0.00	-	-	-	0.05

30.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-12 to 3-13

1.30.1 Prior to 2013, did BC Hydro rely on load research work to develop the load profiles for all of its rate classes, or did some classes have interval metering for billing purposes from which the data could be used?

RESPONSE:

Prior to 2013, BC Hydro relied on load research for all rate classes other than the Transmission Service rate class, which has interval meters.

30.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-12 to 3-13

1.30.2 For each customer class please indicate the % of customers that have interval meters for billing purposes.

RESPONSE:

For each customer class, the per cent of customers with interval meters are shown below:

Rate Class	Percentage of Customers with an Interval Meter (%)
Residential Rate Class	**0**
General Service Rate Classes (SGS, MGS, LGS), Irrigation, Street Lighting	**<1**
Transmission Service Rate Class	**100**

30.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-12 to 3-13

1.30.3 Does the enhanced 45,000 sized sample yield 1% accuracy at the 99% level for all rate classes?

RESPONSE:

The 45,000 sample consists of census (or whole population) samples for the LGS and MGS rate classes, and of statistical samples for the SGS and Residential rate classes. The census samples are expected to yield 1 per cent accuracy at a 99 per cent confidence level. The statistical samples are expected to yield at least 5 per cent accuracy at the 95 per cent confidence level.

31.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-14

1.31.1 Please provide a copy of the analysis supporting BC Hydro's determination that the actual GRTA costs ranged between $42.6 M and $44.2 M in the F2012-2014 period.

RESPONSE:

The table below provides the requested GRTA analysis for the F2012 to F2014 period. The F2016 COS study GRTA costs are shown as "Fixed Fee".

$ million	F2012	F2013	F2014	Average F2012 to F2014
Allowed Return	9.7	8.6	9.1	9.2
Finance Charges	8.5	8.8	9.3	8.9
O&M	6.5	5.4	5.4	5.8
Depreciation & Amortization	9.2	9.0	9.0	9.0
DSM Amortization	-	-	-	-
Grants & Taxes	9.6	10.8	11.5	10.6
Total	**43.6**	**42.6**	**44.2**	**43.5**
Year over Year total Change		(1.0)	1.6	
Fixed Fee	43.3	43.3	43.3	43.3
Difference $	**0.3**	**(0.7)**	**0.9**	**0.2**
Difference %	**0.66%**	**-1.59%**	**2.10%**	**0.39%**

31.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-14

1.31.2 Please briefly describe how functionalizing these costs as generation costs as opposed to transmission changes their classification and allocation to customer classes.

RESPONSE:

The F2016 COS study functionalizes the GRTA costs as Generation. They are classified the same as Heritage hydroelectric assets (55 per cent energy, 45 per cent demand) and subsequently allocated to rate classes using the energy and 4CP allocators.

If the GRTA costs were functionalized to Transmission they would be classified as 100 per cent demand and allocated to rate classes using the 4CP allocator.

32.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-14

1.32.1 Does BC Hydro receive transmission-related revenues for Powerex's use of its transmission system to make energy sales?

RESPONSE:

Yes. These revenues are recorded as Intersegment revenue in the RRA and they offset functionalized transmission costs in the F2016 COS study (refer to Line 45 of RRA Schedule 3.0 and the Intersegment revenues in Schedule 1.0 of the F2016 COS model, both of which are found in Appendix E of Exhibit B-1).

32.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-14

1.32.2 If yes, are these revenues treated as an offset to the costs functionalized as transmission in the COSS?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.32.1.

33.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-15 to 3-19

1.33.1 Please provide a schedule that lists BC Hydro business groups (at the level of detail shown in the RRA financial model, Schedules 5.1 to 5.4), their O&M costs for F2016, and the functional area(s) to which they were mapped. For those business groups that provide services to multiple functional areas, please indicate all of the functional areas involved and what % of the total costs are actually attributable to the functional area the costs are mapped to in the COSS.

RESPONSE:

The functionalization of F2016 business group O&M, which excludes regulatory account recoveries, is shown below.

Business Unit	F2016 O&M ($ million)	Functionalization (%)			
		Generation	Transmission	Distribution	Customer Care
Executive	0.9	30.0	29.7	30.3	9.9
Communications	12.2	30.0	29.7	30.3	9.9
Customer Care and Power Smart	73.2	-	-	-	100.0
Human Resources	54.6	30.0	29.7	30.3	9.9
Finance & Supply Chain	64.6	30.0	29.7	30.3	9.9
Corporate Services & General Counsel	52.6	30.0	29.7	30.3	9.9
IPP Capital Lease Operating Costs	33.8	100.0	-	-	-
Corporate Costs	(98.7)	30.0	29.7	30.3	9.9
Engineering	6.9	100.0	-	-	-
Dam Safety	9.5	100.0	-	-	-
Generation Asset Mgmt.	10.3	100.0	-	-	-

Business Unit	F2016 O&M ($ million)	Functionalization (%)			
		Generation	Transmission	Distribution	Customer Care
Generation Project Delivery	7.4	100.0	-	-	-
Generation Operations	91.0	100.0	-	-	-
Operational Safety	10.6	100.0	-	-	-
Environmental Risk Management	25.6	100.0	-	-	-
Generation Resource Mgmt	13.3	100.0	-	-	-
Energy Planning & Econ Development	9.4	100.0	-	-	-
Business Support	2.1	100.0	-	-	-
Technology	112.3	30.0	29.7	30.3	9.9
Field Operations & Safety	110.4	-	53.4	46.6	-
Grid Operations	37.4	-	53.4	46.6	-
Asset Investment Management	147.1	-	53.4	46.6	-
Project & Program Delivery	14.5	-	53.4	46.6	-
Engineering and Design	22.5	-	53.4	46.6	-
Aboriginal Relations	5.1	-	53.4	46.6	-
Business Support	(1.5)	-	53.4	46.6	-

33.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-15 to 3-19

1.33.2 Please confirm that the approach outlined at 3-17, lines 12-14 was used for Corporate Groups which effectively support all areas of the Corporation (e.g. Executive, Human Resources, SH&E and Finance) and not the approach set out at page 3-15, lines 20-22.

RESPONSE:

In the F2016 COS study, the majority of Corporate Groups are functionalized proportionately with total functionalized O&M, which is consistent with the RRA functionalization. The exceptions are Customer Care and Power Smart, which is functionalized entirely to Customer Care, and IPP Capital Lease Operating Costs which are functionalized entirely to Generation.

As described on page 3-17 lines 12 to 14 of Exhibit B-1, IT costs are functionalized as Generation in the RRA but functionalized as Corporate O&M in the F2016 COS study.

33.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-15 to 3-19

1.33.3 How were the taxes assigned to the Corporate Groups in the RRA financial model functionalized in the COSS?

RESPONSE:

In the F2016 COS study, Corporate taxes are functionalized proportionately with functionalized taxes in RRA Schedule 6.0, lines 30-33.

33.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-15 to 3-19

1.33.4 Would a bottom-up approach for O&M, including IT operating costs (as described on page 3-16 and 3-17) have a material (>5%) impact on the quantum of energy vs. demand vs. customer-related costs allocated to each rate class?

RESPONSE:

As described on page 3-17 of Exhibit B-1, F2016 IT costs account for $112 million (of the total $208 million) O&M including IT costs. Re-functionalizing these costs consistent with the bottom-up method illustrated in Table 3-2 of Exhibit B-1 does not have a material impact on the quantum of energy vs. demand vs. customer-related costs allocated to each rate class. However, since BC Hydro did not use this approach to functionalize corporate O&M costs, it would be speculative to comment on the classification impact for the entire $208 million.

34.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-15 to 3-22

The written Application does not appear to explain how the Non-Tariff, Inter-Segment and Other Utility Revenue shown in the RRA financial model (Schedule 1, lines 7, 8 & 20) were functionalized.

1.34.1 Please describe the sources of Non-Tariff, Inter-Segment and Other Utility Revenue for F2016 and indicate how they were functionalized, with supporting rationale.

RESPONSE:

Non-Tariff Revenue is detailed and functionalized as per Schedule RRA 15.0 in the F2016 COS model provided as Appendix E in Exhibit B-1. SMI revenue is netted from this amount because of its approved regulatory account treatment.

Intersegment Revenue is detailed and functionalized as per Schedule RRA 3.0 in the F2016 COS model provided as Appendix E. Point-to-point revenues are functionalized as Transmission and Corporate Allocations are functionalized as Generation.

Other Utility Revenue is revenue from sales to Seattle City Light. These receipts are applied against the Heritage Payment Obligation and are thus functionalized as 100 per cent Generation.

35.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-19

1.35.1 What is the rationale for the specific Generation, Transmission and Distribution percentages used in the functionalization of DSM costs?

RESPONSE:

Please refer to section 1.1 of the Workshop 5 consideration memo, pages 85 to 87 of 205, Appendix C-2B of Exhibit B-1.

36.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-21 and 3-27

1.36.1 Please provide the rationale for the change in the classification of interest on deferral accounts as described at lines 10-13.

RESPONSE:

Deferral accounts capture variances between forecast and actual cost of energy.

Interest on deferral account balances would be determined to be similarly incurred. Therefore, the energy and demand classification for the interest should mirror that of the cost of energy instead of that for all Generation-related costs.

36.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-21 and 3-27

1.36.2 Please provide a schedule that set out the classification approach for: a) the Recovery associated with the TIDA and b) the interest on each of the TIDA. In doing so please indicate specifically where in Appendix E the classification for each is found.

RESPONSE:

Recoveries associated with the Trade Income Deferral Account (TIDA) are included in Deferral Rider Revenue amount in the F2016 COS model Schedule 1.0 (Appendix E of Exhibit B-1). As shown in Schedule RRA 2.1, interest on the TIDA is added to the outstanding balance in the account while annual recoveries are subtracted, thus allowing interest to be treated consistently with the underlying asset.

The classification of Deferral Rider Revenue is included on Schedule 2.0 of the F2016 COS model, showing that this amount is classified consistent with Heritage Hydro costs as 45 per cent demand related and 55 per cent energy related.

Powerex net income is included in Subsidiary Net Income on Schedule 1.0 and its classification is shown on Schedule 2.0 of the F2016 COS model. As described in section 3.7.5 on page 3-27 of Exhibit B-1, this classification is tied to the overall classification of all Generation-related costs.

The classification for the TIDA (through the Deferral Rider Revenue) and the classification of the Powerex net income (through Subsidiary Net Income) differ because Deferral Rider Revenue is not solely related to the TIDA and the Subsidiary Net Income is not solely related to Powerex.

36.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-21 and 3-27

1.36.3 If the classification of the recovery is not the same as for the classification of the interest, please explain why different methodologies are used for each.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.36.2.

36.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-21 and 3-27

1.36.4 Please provide a schedule that sets out the classification approach for: a) the Recovery associated with the TIDA and b) the Powerex Net Income. In doing so, please indicate specifically where in Appendix E the classification of each is found.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.36.2.

36.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-21 and 3-27

1.36.4 Please provide a schedule that sets out the classification approach for: a) the Recovery associated with the TIDA and b) the Powerex Net Income. In doing so, please indicate specifically where in Appendix E the classification of each is found.

1.36.4.1 If the classification approaches are different, please explain why.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.36.2.

37.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-23 to 3-25

1.37.1 Throughout section 3.7.1, frequent use is made of the term "Generation". Please confirm that in each case the reference is to "Heritage Hydro Generation". For example, in lines 7-8, please confirm that BC Hydro is expressing a preference for a 55% energy/45% demand split for Heritage Hydro Generation and not all Generation.

RESPONSE:

Confirmed.

37.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-23 to 3-25

1.37.2 How does the choice between classification methods for Heritage Hydro Generation impact the quantum of energy vs. demand-related costs allocated to each rate class? Please provide a schedule that sets out separately the Generation Demand and Energy Costs that are allocated to each rate class using each method, where Total Generation cost will be the ($2,595.3 M) shown in the COSS, Schedule 2.0.

RESPONSE:

The following tables show the energy, demand-related costs and total generation costs allocated to each rate class under the three hydroelectric classification options which are described in section 4 of the Workshop 4 discussion guide (pages 65 to 67 of 205, Appendix C-2B, Exhibit B-1).

Table 1 Generation Energy-related Costs ($million)

Rate Class	Option 1A System Load Factor	Option 1B System Load Factor Adjusted for IPPs (Adopted in the F2016 COS Study)	Option 3 Capacity Factor
Residential	732.1	708.4	669.1
SGS	144.6	140.0	132.2
MGS	133.5	129.2	122.0
LGS	431.7	417.8	394.5
Irrigation	3.1	3.0	2.8
Street Lighting	9.0	8.7	8.2
Transmission	591.4	572.3	540.5

Table 2 Generation Demand-related Costs ($million)

Rate Class	Option 1A	Option 1B (Adopted in the F2016 COS Study)	Option 3
Residential	252.1	282.4	332.9
SGS	39.7	44.5	52.4
MGS	35.4	39.7	46.8
LGS	101.3	113.4	133.7
Irrigation	0.0	0.0	0.0
Street Lighting	3.3	3.7	4.3
Transmission	118.1	132.3	155.9

Table 3 Total Generation Costs ($million)

Rate Class	Option 1A	Option 1B (Adopted in the F2016 COS Study)	Option 3
Residential	984.2	990.8	1,002
SGS	184.3	184.5	184.6
MGS	168.9	168.9	168.8
LGS	533	531.2	528.2
Irrigation	3.1	3	2.8
Street Lighting	12.3	12.4	12.5
Transmission	709.5	704.6	696.4
Total Generation Costs	2,595.3	2,595.3	2,595.3

37.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-23 to 3-25

1.37.3 Does the system load factor calculation used for Heritage Hydro Generation exclude the load in the Fort Nelson Service Territory?

RESPONSE:

Yes. As described in BC Hydro's response to BCUC IR 1.25.1, the system load factor calculation is based on integrated system load forecasts found in the 2013 IRP Base Resource Plan.

37.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-23 to 3-25

1.37.3 Does the system load factor calculation used for Heritage Hydro Generation exclude the load in the Fort Nelson Service Territory?

1.37.3.1 If not, why not given that FNG (like IPPs) is classified separately?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.37.3.

38.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-25 and Appendix E, F2016 COSS - Schedule 2.0

1.38.1 At page 3-25 BC Hydro proposes different classification treatments for each of FNG, PRG and Burrard as compared to that proposed for Heritage Hydro Generation. However, in Schedule 2.0 all Thermal O&M costs are classified on the same basis as Heritage Hydro Generation. Similarly, all Depreciation, Taxes and Finance charges associated with Generation (including Thermal Generation) are classified on the same basis as Heritage Hydro Generation. Please reconcile and clarify what classification was used for Heritage Thermal Generation.

RESPONSE:

The classification methodology of Heritage thermal costs was determined to have negligible impact on final F2016 COS results. In the interest of simplicity, BC Hydro did not include the additional calculations to the F2016 COS model.

38.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-25 and Appendix E, F2016 COSS - Schedule 2.0

1.38.2 Please set out separately the classification of the costs (excluding Fuel) for each of FNG, PRG and Burrard using the approaches described at page 3-25.

RESPONSE:

The total Demand percentage and Energy percentage values in row 7 columns C and D are derived from the Total Demand $ and Energy $ in row 7 columns E and F.

Please note that the 55 per cent Energy classification used in the F2016 COS model was rounded down (from 55.11 per cent). The rounded totals provided in row 7 in the table below have been similarly rounded to the nearest percentage point.

	A	B	C	D	E	F
1	**Heritage Hydro Generation**	**F2016 Assets NBV ($ million)**	**Demand-related (%)**	**Energy-related (%)**	**Demand ($ million)**	**Energy ($ million)**
2	**Non-Thermal**	**5,248.3**	**45**	**55**	**2,551.7**	**3,118.8**
3	**FNG**	**152.0**	**26**	**74**	**44.7**	**127.1**
4	**PRG**	**9.2**	**40**	**60**	**4.3**	**6.4**
5	**Burrard**	**51.4**	**100**	**0**	**80.2**	**0.0**
6	**Total Thermal**	**212.6**	**49**	**51**	**129.2**	**133.5**
7	**Total**	**5,460.9**	**45**	**55**	**2,680.9**	**3,252.3**

39.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-27 (lines 1-3) & pages 2-47 to 2-49 and Appendix E, F2016 COSS - Schedule 2.0

1.39.1 At page 3-27 it states that BC Hydro believes the classification of Generation-related DSM costs should mirror the classification of overall Generation costs. However, in Schedule 2.0 of the COSS all Generation-related Depreciation and Amortization (including that for DSM) is classified on the same basis as Heritage Hydro Generation (45%-D/55%-E). Please reconcile.

RESPONSE:

The proposed classification methodology for Generation-related DSM costs was not reflected in the F2016-COS model. The F2016 DSM amortization amount of $74.98 million was previously classified as 45 per cent demand-related and 55 per cent energy-related costs. Applying the overall Generation costs classification of 23.1 per cent demand-related and 76.9 per cent energy-related results in a shift of $16.42 million from demand to energy.

The overall Generation costs classification is also applied to Subsidiary Net Income and the re-weighting of DSM Amortization changes the classification of these costs by shifting $0.1 million from demand to energy.

The impact to R/C ratios of this correction is less than a 0.5 per cent change by rate class.

A revised series of COS schedules reflecting among other things this adjustment to Schedule 2.0 is provided as Attachment 1 to this response.

39.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-27 (lines 1-3) & pages 2-47 to 2-49 and Appendix E, F2016 COSS - Schedule 2.0

1.39.2 Please confirm that the alternatives to DSM are undertaking IPP EPA renewals and initiating new green-field IPP clean or renewable acquisition processes.

RESPONSE:

Generally confirmed. Note that the difference in capacity contribution between DSM and these IPP alternatives might trigger a need for additional capacity resources.

39.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-27 (lines 1-3) & pages 2-47 to 2-49 and Appendix E, F2016 COSS - Schedule 2.0

1.39.2 Please confirm that the alternatives to DSM are undertaking IPP EPA renewals and initiating new green-field IPP clean or renewable acquisition processes.

1.39.2.1 If not confirmed, what are the alternatives to DSM?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.39.2.

39.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-27 (lines 1-3) & pages 2-47 to 2-49 and Appendix E, F2016 COSS - Schedule 2.0

1.39.2 Please confirm that the alternatives to DSM are undertaking IPP EPA renewals and initiating new green-field IPP clean or renewable acquisition processes.

1.39.2.2 If confirmed, why wouldn't it be more appropriate to classify Generation-related DSM using the same percentages for demand and energy as proposed for IPPs?

RESPONSE:

The F2016 COS study classifies IPPs as 93 per cent energy-related and 7 per cent demand-related. This classification would significantly under estimate the demand-related benefits of DSM.

BC Hydro notes that DSM reduces load which can be considered to be about 60 per cent energy and 40 per cent demand used on the system load factor.

BC Hydro attached an amended COS model to the response to BCOAPO IR 1.39.1 which classifies DSM costs the same as overall generation costs (about 76 per cent energy and 24 per cent demand). BC Hydro believes this corrected DSM treatment is appropriate given the above considerations.

40.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-27 to 3-29; Appendix C-2A – Leidos Report (December 2013) and Reimer Report (May 2010)

1.40.1 Please provide a schedule that indicates the proposed methodology and resulting classification percentages for Substations, Primary, Transformers, Secondary, Services and Services as recommended by each of the consultants (Leidos and Reimer).

RESPONSE:

The COS Consultants (Leidos) have endorsed BC Hydro's proposed classification for distribution cost.

The requested table follows below:

Asset Category	BC Hydro's F2016 COS Study Methodology	Electric Distribution System Study by Arnie Reimer "Appropriate Method"
Substations	100% Demand	100% Demand
Primary System	100% Demand	98% Demand; 1.6% Customer
Transformers	50% Demand; 50% Customer	38% Demand; 62% Customer
Secondary/Services Asset Category (Split 50% Secondary; 50% Services)	Secondary Portion 100% Demand	3% Demand; 97% Customer
	Service Portion 100% Customer	This was not separately analyzed and was likely part of the "Secondary" category shown in Tables 27 and 28 of the Reimer report
Meters	100% Customer	100% Customer

40.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-27 to 3-29; Appendix C-2A – Leidos Report (December 2013) and Reimer Report (May 2010)

1.40.2 The 2015 RDA states (page 3-28) that the COS consultants recommended approach (3) – use of professional judgement to separate demand-related and customer-related distribution costs. Please provide the relevant references for the Leidos and Reimer Reports where this recommendation can be found.

RESPONSE:

On numerous occasions during the 2015 RDA engagement process BC Hydro consulted with the COS Consultants on various COS topics, including the classification of Distribution costs.

The recommendation to use professional judgement in the classification was provided orally.

40.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-27 to 3-29; Appendix C-2A – Leidos Report (December 2013) and Reimer Report (May 2010)

1.40.3 At page 3-29 BC Hydro states that Bonbright rejects the minimum system and zero-intercept methodologies. What approach does Bonbright view as being acceptable?

RESPONSE:

With reference to footnote 140 on page 3-29 of Exhibit B-1, Bonbright states on page 347:

> ***"While, for the reason just suggested, the inclusion of the costs of a minimum sized distribution system among the customer related costs seems to me clearly indefensible, its exclusion from the demand-related costs stands on much firmer ground. For this exclusion makes more plausible the assumption that the remaining cost of the secondary distribution system is a cost which varies continuously with the maximum demand imposed on the system as measured by peak load."***

Bonbright does not present a clear solution to the problem. On page 348 he goes on to state:

> ***"the only defensible answer, in my opinion, is that costs, from the secondary, low-voltage distribution system, belong to none of them (not demand or customer related)" and that "it should be recognized as a strictly unallocable portion of total costs".***

Bonbright goes on to acknowledge that such an approach is likely not conducive to an embedded cost of service study which require that the "sum of the parts equal the whole".

40.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-27 to 3-29; Appendix C-2A – Leidos Report (December 2013) and Reimer Report (May 2010)

1.40.4 Please re-do Tables 27 and 28 from the Reimer Report using the F2016 Revenue Requirement and BC Hydro's' proposed functionalization (and sub-functionalization) of costs. Please add a row to each Table reflecting BC Hydro's recommended approach for each Distribution "sub-function".

RESPONSE:

Tables 27 and 28 from the Electric Distribution System Report page 161 of 439 (Appendix C-2A, Exhibit B-1) has been reproduced below with the requested amendments.

Table 27

Total, Customer and Demand-related portions of Revenue Requirement (Based on the F2016 RRA and BC Hydro's proposed Sub-functionalization of Distribution costs but not including certain customer-related costs such as the SMI deferral recoveries)
All values in $million

Summary	SDA	Primary	Transformers	Secondary	Services	Meters	Total
Total Net Book Value ($million)		2,176.2	666.8	288.1	288.1	498.0	
Total Revenue Requirement ($million)	148.3	443.3	135.8	58.7	58.7	101.4	946.2
Customer Related							
Zero Intercept (Segments) (%)	0.0	51.4	62.4	74.1	N.A	0.0	
Zero Intercept (Aggregate) (%)	0.0	51.4	42.6	74.1	N.A	0.0	
Min System (%)	0.0	54.7	74.8	97.4	N.A	0.0	
Direct Assignment (%)	0.0	0.0	100.0	100.0	N.A	100.0	
Cap Expenditure (%)	N.A	1.6	N.A	N.A	N.A	N.A	
F2016 COS Method (%)	0.0	0.0	50.0	0.0	100.0	100.0	
Demand Related							
Zero Intercept (Segments) (%)	100.0	48.6	37.6	25.9	N.A	100.0	
Zero Intercept (Aggregate) (%)	100.0	48.6	57.4	25.9	N.A	100.0	
Min System (%)	100.0	45.3	25.2	2.6	N.A	100.0	
Direct Assignment (%)	100.0	100.0	0.0	0.0	N.A	0.0	
Cap Expenditure (%)	N.A	98.4	N.A	N.A	N.A	N.A	
F2016 COS Method (%)	100.0	100.0	50.0	100.0	0.0	0.0	

Table 28

Total, Customer and Demand-related portions of Revenue Requirement (Based on the F2016 RRA and BC Hydro's proposed Sub-functionalization of Distribution costs but not including certain customer-related costs such as the SMI deferral recoveries)
All values in $million

Summary	SDA	Primary	Transformers	Secondary	Services	Meters	Total
Total Net Book Value ($million)		2,176.2	666.8	288.1	288.1	498.0	
Total Revenue Requirement ($million)	148.3	443.3	135.8	58.7	58.7	101.4	946.2
Customer Related							
Zero Intercept (Segments) (%)	0.0	227.8	84.8	87.0	0.0	0.0	399.5
Zero Intercept (Aggregate) (%)	0.0	227.8	57.9	87.0	0.0	0.0	372.7
Min System (%)	0.0	242.5	101.6	114.3	0.0	0.0	458.4
Direct Assignment (%)	0.0	0.0	135.8	117.3	0.0	101.4	354.6
Cap Expenditure (%)	N.A.	7.1	N.A.	N.A.	0.0	N.A.	7.1
Appropriate Method (%)	0.0	7.1	84.8	114.3	0.0	101.4	307.6
F2016 COS Method (%)	0.0	0.0	67.9	0.0	58.7	101.4	228.0
Demand Related							
Zero Intercept (Segments) (%)	148.3	215.4	51.1	30.4	0.0	101.4	546.6
Zero Intercept (Aggregate) (%)	148.3	215.4	78.0	30.4	0.0	101.4	573.5
Min System (%)	148.3	200.8	34.2	3.1	0.0	101.4	487.8
Direct Assignment (%)	148.3	443.3	0.0	0.0	0.0	0.0	591.5
Cap Expenditure (%)	N.A.	436.2	N.A.	N.A.	0.0	N.A.	
Appropriate Method (%)	148.3	436.2	51.1	3.1	0.0	0.0	638.6
F2016 COS Method (%)	148.3	443.3	67.9	58.7	0.0	0.0	718.1

40.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-27 to 3-29; Appendix C-2A – Leidos Report (December 2013) and Reimer Report (May 2010)

1.40.5 Please provide a new Schedule based on the results from part (4) that sets out the total demand and total customer-related costs allocated to each rate class based on each of the seven methods (i.e., the 6 reported in the original Table 28 plus BC Hydro's approach).

RESPONSE:

Below is a breakout of the $946 million in distribution costs, identified in BC Hydro's response to BCOAPO IR 1.40.4, into demand-related and customer-related components using the methodologies found in the Electric Distribution System Report (the Reimer Report), refer to page 161 of 439, Appendix C-2A, Exhibit B-1. The Capital Expenditure methodology has been excluded because the Reimer Report only considered it for the primary distribution system.

The main differences between the Reimer Report's "Appropriate Method" and the F2016 COS method are the classification of transformers (which the Reimer Report considered primarily customer-related) and secondary/services (which the Reimer Report considered almost entirely customer-related).

	Demand-related Costs under Different Methodologies					
$ million	Zero Intercept (Segments)	Zero Intercept (Aggregate)	Minimum System	Direct Assignment	Reimer Report Appropriate Method	F2016 COS Method
Residential	310	325	276	335	362	414
GS Under 35 kW	58	61	52	63	68	81
MGS < 150 kW	51	53	42	51	55	71
LGS > 150 kW	121	128	112	137	147	144
Irrigation	2	2	2	3	3	3
Street Lighting	1	1	1	1	1	2
Transmission	2	3	2	3	3	3
Total	547	574	488	591	639	718

	Customer-related Costs under Different Methodologies					
$ million	Zero Intercept (Segments)	Zero Intercept (Aggregate)	Minimum System	Direct Assignment	Reimer Report Appropriate Method	F2016 COS Method
Residential	355	331	407	303	261	175
GS Under 35 kW	37	34	42	39	35	33
MGS < 150 kW	4	3	4	7	7	13
LGS > 150 kW	1	1	1	3	2	6
Irrigation	1	1	1	1	1	1
Street Lighting	1	1	1	1	1	0
Transmission	2	3	2	3	3	3
Total	399	373	458	355	308	228

41.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-29 to 3-30

1.41.1 Does the choice of classification methods for SMI materially impact the quantum of energy vs. customer-related costs allocated to each rate class?

RESPONSE:

Recovery of SMI deferral account costs is $31.3 million in F2016, less than 1 per cent of the F2016 annual revenue requirement of $4,459.7 million. As such, the method selected for classification of these costs has a minimal impact on total energy- and customer-related costs allocated by rate class.

42.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-31

1.42.1 Is the same 6% distribution loss factor used for all distribution customers regardless of their service voltage?

RESPONSE:

No. As shown in Schedule 5.0 to the F2016 COS model (Appendix E to Exhibit B-1), a 3.44 per cent assumption is used for primary distribution customers while 6.0 per cent is used for secondary distribution customers. These same loss assumptions are also applied to the load research data when calculating 4CP and NCP allocators.

42.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-31

1.42.1 Is the same 6% distribution loss factor used for all distribution customers regardless of their service voltage?

1.42.1.1 If yes, do all distribution customers have the same notional metering point (i.e., the point at which energy is assumed to delivered and measured for billing purposes)?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.42.1.

43.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-33 and 3-13

1.43.1 For the current 2015 RDA, for how many of the five years of data used in determining the NCP values was based on the broader sample of data available from SMI reads vs. load research work.

RESPONSE:

The NCP five-year average was based on fiscal years 2010 through 2014. The SMI data became available part of the way through F2014 and so SMI data was used for a portion of this data set.

43.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, page 3-33 and 3-13

1.43.2 For the Residential class, please provide the ratio of 1 NCP (kW) to total energy (kWh) for each of the five years used in the averaging and indicate which years are based on SMI reads.

RESPONSE:

As noted in BC Hydro's response to BCOAPO IR 1.43.1, the data from F2014 includes SMI reads.

Please note that the ratios comparing demand and energy have been calculated by first converting kWh to MWh.

Residential	NCP (kW)	Energy (kWh)	Ratio kW:MWh (%)
F2014	4,685,439	19,043,422,210	26.4
F2013	4,192,551	18,765,301,911	23.5
F2012	4,881,549	19,498,444,983	27.2
F2011	4,529,403	18,865,246,639	25.2
F2010	4,766,001	18,648,901,466	27.4

44.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-34 to 3-35

1.44.1 Please provide a schedule that sets out all of the COSS methodology changes as between the 2007 RDA (as approved by the Commission) and the currently proposed methodology.

RESPONSE:

Table 3-1 of Exhibit B-1 summarizes methodology changes, related to Commission directives, between the 2007 RDA and the F2016 COS study.

Please refer to BC Hydro's response to FortisBC IR 1.2.1 for a list of other methodology changes.

45.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-33 to 3-34 and Appendix E, COSS – Schedules 3.2

Schedule 3.2 reports Distribution Transformer-related costs of $142.7 M and calculates the value by applying the percent of distribution assets (excluding street lighting) that are accounted for by transformers for Sheet 6.0 to the difference between the values reported in Schedule 2.2 at cells D76 and D73. In principle these two cells should represent the total value of all distribution assets and the total value of street lighting assets respectively. However, D73 represents the Internal Allocations functionalized as Distribution and H76 represents the costs directly assigned to Street Lighting. There appears to be a similar issue with the calculation of the values reported in cell F5.

1.45.1 Please review the formulae used in Schedule 3.2 and address the issues outlined in the preamble.

RESPONSE:

The Distribution sub-functionalization ratios from F2016 COS Schedule 6.0 are applied to those Demand and Energy Distribution costs that cannot be directly attributed to the sub-functions.

The purpose of the calculation in F2016 COS Schedule 3.2 cell H5 is to calculate the total transformer-related costs to allocate to rate classes. The amount of $142.7 million was determined as the proportion of remaining costs functionalized to Distribution less those costs directly sub-functionalized as substation related. Similarly, the purpose of the calculation in F2016 COS Schedule 3.2 cell F5 is to calculate the total Secondary-related costs to allocate to rate classes. The amount of $61.64 million was determined as the proportion of remaining costs functionalized to Distribution less those costs directly sub-functionalized as substation related.

However, the formula incorrectly references total Distribution costs, including those to be directly assigned to the Street Lighting rate class instead of referencing the sum of the remaining Demand and Energy costs to be sub-functionalized. The impact of reducing total Secondary-related and Transformer-related costs each by the appropriate proportion (from F2016 COS Schedule 6.0, 14.7 per cent and 17 per cent respectively) of $4.61 million results in a change in the R/C ratio for each rate class of less than 0.05 per cent.

A revised series of COS schedules reflecting this adjustment to Schedule 4.0 is found at Attachment 1 of BC Hydro's response to BCOAPO IR 1.39.1.

46.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-33 to 3-34 and Appendix E, COSS – Schedules 5.4

1.46.1 Please explain how the breakdown between OH and UG transformers set out in Row 12 was done.

RESPONSE:

The methodology is based on Option 1 as described on slides 45 to 52 of the Workshop 4 presentation found on pages 45 to 52 of 205 in Appendix C-2B of Exhibit B-1.

The breakdown between OH and UG transformers in row 12, Schedule 5.4, Appendix E of Exhibit B-1 represent a weighted value of overhead and underground BC Hydro-owned transformers that is based on the number of transformers and the cost of installation.

46.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-33 to 3-34 and Appendix E, COSS – Schedules 5.4

1.46.2 Please confirm that the allocation to rate classes was done use Option 1 (Direct Assignment) per the October 7, 2014 Workshop Presentation.

RESPONSE:

Confirmed.

46.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-33 to 3-34 and Appendix E, COSS – Schedules 5.4

1.46.2 Please confirm that the allocation to rate classes was done use Option 1 (Direct Assignment) per the October 7, 2014 Workshop Presentation.

1.46.2.1 If not, how was the allocation performed?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.46.2.

47.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-33 to 3-34 and Appendix E, COSS – Schedules 6.0

1.47.1 With respect to the year-end asset values used in Schedule 6.0, please clarify whether these are gross or net book values and whether or not they are net of capital contributions received from third parties.

RESPONSE:

The sub-functionalization of distribution costs between substations, primary system, transformers, secondary, services, and meters shown in Schedule 6.0 of the F2016 COS model (Appendix E, Exhibit B-1) is based on each category's share of F2014 distribution rate base.

Distribution rate base represents the net book value of the distribution system, net of any Contributions in Aid of Construction.

47.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 3-33 to 3-34 and Appendix E, COSS – Schedules 6.0

1.47.2 Please explain why the asset value selected is appropriate for assigning to Distribution sub-functions each of the following:

(a) Operating Costs;
(b) Depreciation; and
(c) Financing Costs.

RESPONSE:

Operating Costs

Information is not currently available to directly assign operating (OM&A) expenses into the distribution sub-functions shown in Schedule 6.0 of the F2016 COS study, Appendix E, Exhibit B-1. Therefore, BC Hydro determined the next best option is to sub-functionalize OM&A costs in accordance with sub-functionalized asset costs. Given the lack of the ability to directly assign OM&A costs, the COS Consultants advised that it is common to sub-functionalize O&MA costs based on relative asset values.

Depreciation

Information is not currently available to directly assign depreciation expenses into the distribution sub-functions shown in Schedule 6.0. Therefore, BC Hydro determined the next best option is to sub-functionalize depreciation expenses in accordance with sub-functionalized gross asset values because the gross values represent the original cost of the asset being depreciated. However, this was not possible in the F2016 COS study because the accounting system's gross values were overwritten with net book values when IFRS was implemented. Given this, BC Hydro and the COS Consultants consider the net book values to be a reasonable proxy to sub-functionalize depreciation costs.

Financing Costs

Information is not currently available to directly assign distribution financing costs to the distribution sub-functions shown in Appendix E, Schedule 6.0. Therefore, BC Hydro determined the next best option is to sub-functionalize financing costs in accordance with sub-functionalized net value of assets. Assets that have been in service for many years and are fully depreciated are expected to have little financing cost while recent capital additions would likely have higher financing costs associated with them. For this reason net book values are used in the sub-functionalization of financing costs. Given the lack of the ability to directly assign financing costs, the COS Consultants advised that it is relatively common to sub-functionalize financing costs based on relative net book values of assets.

48.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 1-1 & 1-2, and Section 3.1.2 Rate Increases and next Rate Design Application

1.48.1 BC Hydro states that rate caps will be in place until 2019, and that it will file an F2019 COS. When does BC Hydro expect to file its next RDA?

RESPONSE:

It is too early for BC Hydro to determine when it will file its next comprehensive RDA. A number of factors would inform the timing of such a decision:

- **Timing of the review of RDA Module 2;**
- **Timing of the review the F2019 COS and any rate rebalancing recommendations;**
- **Any material changes to BC Hydro's operating environment, including B.C. Government policy.**

As a result, BC Hydro does not anticipate filing a comprehensive RDA prior to F2020/F2021. BC Hydro also notes that as has been done in the past, individual rate initiatives can be submitted to the Commission between RDAs.

48.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 1-1 & 1-2, and Section 3.1.2 Rate Increases and next Rate Design Application

1.48.2 Will the next RDA be filed as part of the proposed F2019 COS?

RESPONSE:

No. Please refer to BC Hydro's response to BCOAPO IR 1.48.1.

48.0 CHAPTER 3 COST OF SERVICE

Reference: Exhibit B-1, pages 1-1 & 1-2, and Section 3.1.2 Rate Increases and next Rate Design Application

1.48.3 What are BC Hydro's projected rate increases for 2016-2025?

RESPONSE:

As described in section 1.3 of Exhibit B-1, pages 1-16 to 1-17, BC Hydro used the rate caps set out in section 9 of Direction No. 7 for modelling various rate designs to determine customer bills impacts. Those rate caps are:

Rate Caps (%)		
F2017	**F2018**	**F2019**
4	**3.5**	**3**

BC Hydro respectfully declines to respond to the request for BC Hydro's forecasted rate increases for the period F2020 to F2024 on the basis that such information is not relevant to and cannot aid in the review of 2015 RDA Module 1 or the orders sought with respect to it. As described in section 1.1.3 of Exhibit B-1, BC Hydro is seeking Commission approval of pricing principles for the RIB rate and RS 1823 for the F2017 to F2019 period only.

BC Hydro notes that a discussion of BC Hydro's forecasted rate increases for the period F2020 to F2024 will occur as part of its F2017 RRA filing in February 2016.

49.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, pages 4-3 to 4-5 and 4-8

At page 4-8, BC Hydro states that "Low load factors are indicative of customers that are more costly to serve, and load factor is therefore a consideration when evaluating rate class segmentation". Given this acknowledged relationship between load factor and cost to serve, information regarding load factor characteristics of customers within a class may also be useful for rate design and well as class segmentation purposes.

1.49.1 Please provide an assessment of the relationship between individual Residential customers' annual energy use and load factor that indicates whether there are any changes in load factor as annual energy use increases and, if so, where the "break points" exist. In doing so, please calculate using each of the following definitions of load factor:

1.49.1.1 Total average energy use vs. a customer's demand coincident with overall system peak demand (4CP).

1.49.1.2 Total average energy use vs. a customer's demand coincident with the Residential class NCP.

RESPONSE:

Customer load factor is typically calculated as energy use divided by peak use over a specific period of time. ("$LF_{NCP\text{-}customer}$").

For the requested analysis in IR 1.49.1.1, "load factor" is defined as energy use divided by customer use at system coincident peak (4CP) use ("LF_{4CP}"). Note that this can produce load factor percentages greater than 100 per cent if the customer's demand at the system peak interval is very low relative to their average demand.

For the requested analysis in IR 1.49.1.2, "load factor" is defined as energy use divided by customer use at class coincident peak (NCP) use ("$LF_{NCP\text{-}class}$"). Note that this can produce load factor percentages greater than 100 per cent if the customer's demand during the rate class peak interval is very low relative to their average demand.

Consider a customer with peak use of 8.44 kW and 11,506 kWh over an one-year period. The customer's system coincident peak use in November, December, January, and February was 1.87, 2.79, 2.58, and 2.82 kW. At the rate class annual peak, customer use was 1.74 kW.

$LF_{NCP\text{-}customer}$ = 11,506 kWh/[8.44 kW * 8760 hours] = 15.6%

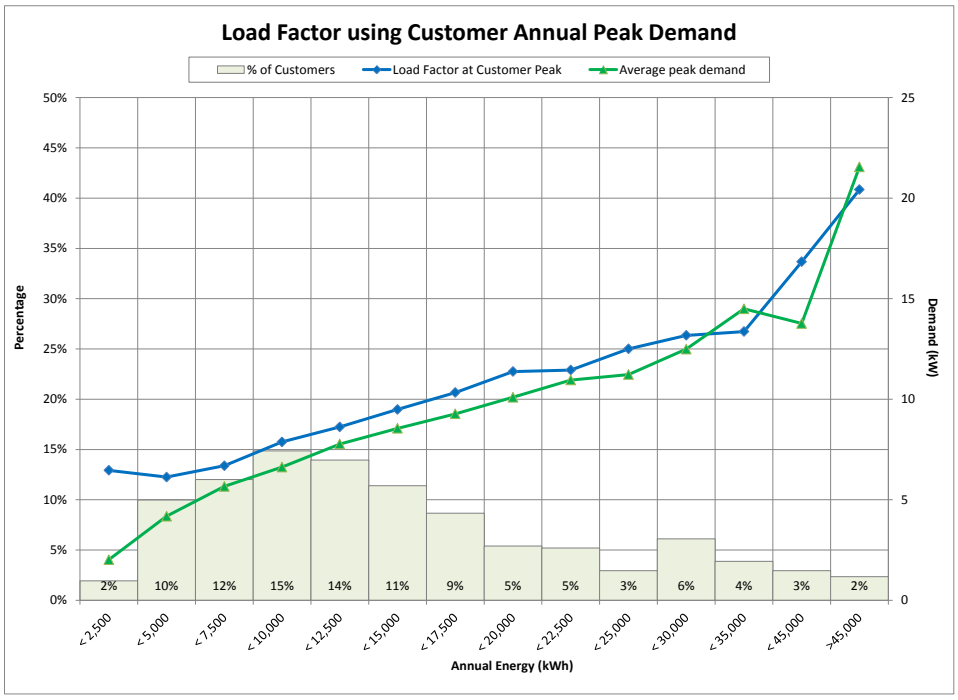
LF_{4CP} = 11,506 kWh/[(average (1.87, 2.79, 2.58, 2.82) kW * 8760 hours] = 52.2%

$LF_{NCP\text{-}class}$ = 11,506 kWh/[1.74 kW * 8760 hours] = 75.5%

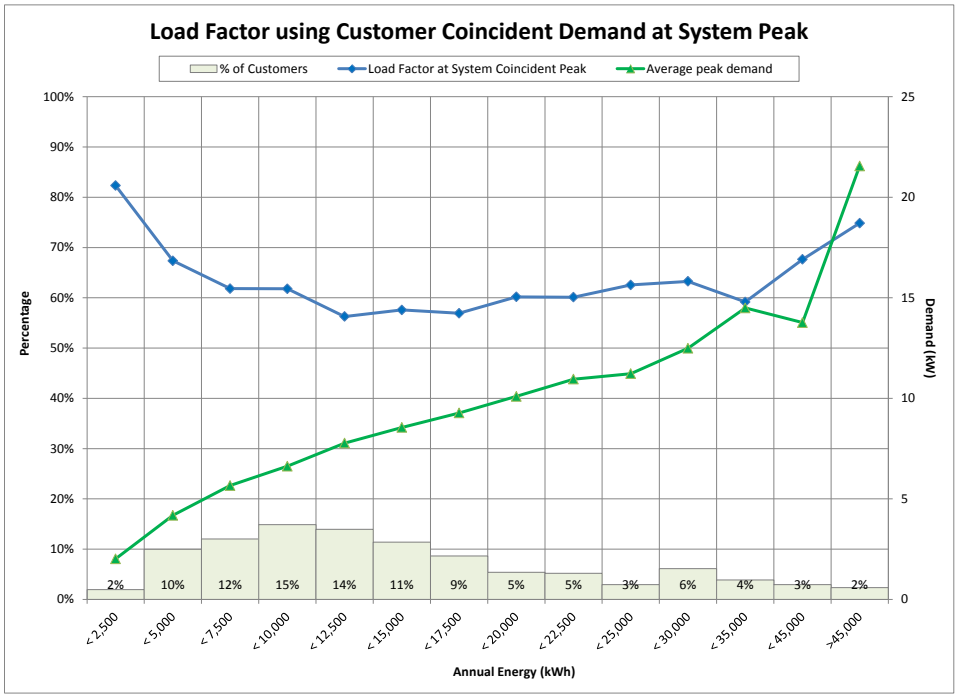
BC Hydro observes that all three methods seem to show a "break point" at 35,000 kWh which is associated with peak demand just below 15 kW in the Residential class. However, BC Hydro notes the relatively small number of customers in the sample (< 5 per cent) who are above this break point. Further, as BC Hydro described during Workshop 12 (page 34 of 115 of Appendix C-1B in Exhibit B-1), customer size (as determined by annual peak demand) is correlated with coincidence. Given the importance of coincident peak demand with system peak in determining cost causation, further analysis into this attribute together with associated costs must also be considered. In addition as noted in section 4.2.1 of Exhibit B-1 all surveyed Canadian electric utilities have a single uniform residential class of customers.

To appropriately assess the relationship between customer energy use and the different methods of calculating load factor, a random sample of 1000 Tesidential customers was drawn and collapsed into segments. The following graphs illustrate the relationship between customer energy use, load factor, and peak demand using the different methodologies. The relationship between conventional load factor and energy use is also included for comparison.

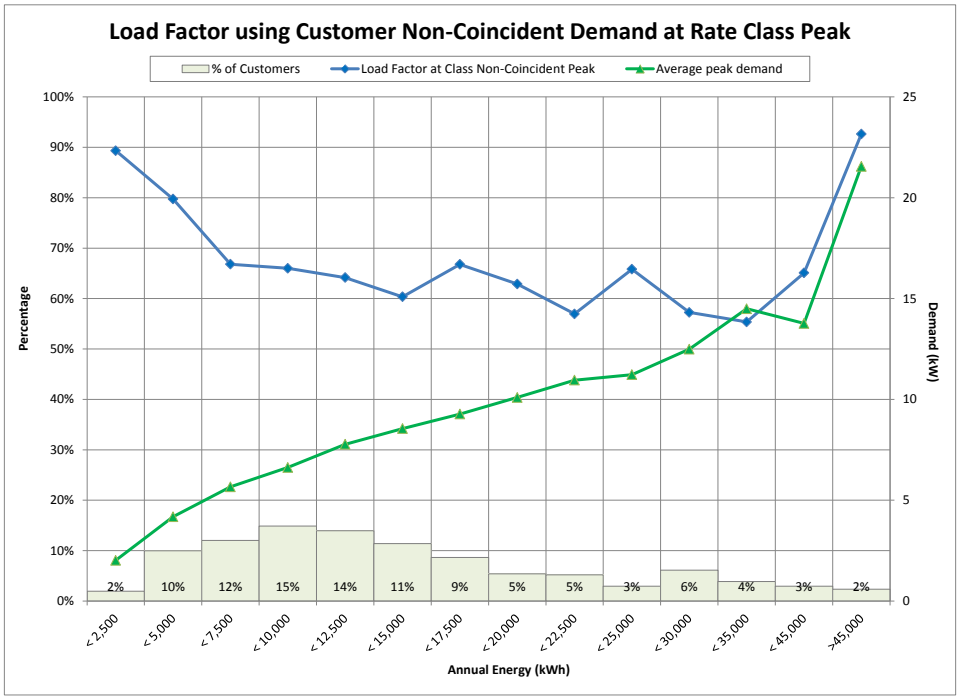
Conventional Load Factor



Load Factor at System Peak as per 1.49.1.1



Load Factor at Class Peak as per 1.49.1.2



50.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, page 4-5 and 5-51

BC Hydro concludes that the impact of making Residential E-Plus customers a separate class was too insignificant to justify such a change.

1.50.1 What is the annual energy use of Residential E-Plus customers?

RESPONSE:

The R/C ratio estimates for E-Plus customers are based on F2014 energy consumption and load research information. In that year, energy sales to residential E-Plus customers were about 96 GWh on RS 1105 and another 88 GWh on other residential rates associated with the same site address (i.e., RS 1101, RS 1111, RS 1121 and RS 1151).

50.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, page 4-5 and 5-51

BC Hydro concludes that the impact of making Residential E-Plus customers a separate class was too insignificant to justify such a change.

1.50.2 Page 5-51 discusses the R/C ratios for portions (i.e., heating and non-heating load) of Residential E-Plus customers' load but not overall values. If Residential E-Plus customers were a separate rate class what would be its overall R/C ratio under the following two circumstances:

(a) Generation energy costs are not assigned to Residential E-Plus heating load; and
(b) Generation energy costs are assigned to Residential E-Plus heating load.

RESPONSE:

The overall R/C ratio for an E-Plus rate class would be about:

- **80 per cent if no generation energy costs are assigned to the RS 1105 energy sales; and**
- **65 per cent if generation energy costs are assigned to the RS 1105 energy sales.**

Both of the above calculations assume that energy costs continue to be fully assigned to residential loads that are associated with the RS 1105 E-Plus accounts at the same site address (i.e., non E-Plus residential loads).

50.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, page 4-5 and 5-51

BC Hydro concludes that the impact of making Residential E-Plus customers a separate class was too insignificant to justify such a change.

1.50.3 Given the proposed changes to the terms and conditions for Residential E-Plus, what would be its overall R/C ratio if no energy or capacity related costs were allocated?

RESPONSE:

The overall R/C ratio for an E-Plus class would be 140 per cent if no energy or demand-related costs were assigned to the RS 1105 accounts. However, even with BC Hydro's proposed amendment to RS 1105, it has not yet been established that a truly interruptible RS 1105 is a long-term resource that BC Hydro can rely on to meet its capacity needs. Given this, it is BC Hydro's view that Residential E-Plus accounts should continue to attract Residential demand-related costs.

51.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, page 4-9 (lines 5-13)

1.51.1 In 2009, did E3 recommend a breakpoint for the LGS vs. MGS classes and, if so, what was it?

RESPONSE:

In its segmentation analysis presented in Appendix K of the 2009 LGS application, E3 identified several possible breakpoints in the then Existing Large General Service rate class that were supported by COS data. Both 100 kW and 150 kW were observed to be reasonably defendable breakpoints for differentiating customer classes. However, the 150 kW breakpoint was ultimately selected as that which was best supported by COS analysis.

52.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, page 4-10 (lines 6-19)

BC Hydro concludes at lines 11-12 that "a customer's coincident peak demand is a major consideration in segmenting customer classes". However, at lines 17-19, BC Hydro also concludes that "since distribution costs are assigned proportionate to NCP, the cost per NCP kW does not vary and a $/kW analysis cannot be used to identify cost differences between segments".

1.52.1 Please confirm that for Generation and Transmission demand costs the costs are assigned proportionate to 4CP and the costs per 4CP does not vary by the customer's size.

RESPONSE:

Confirmed.

52.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, page 4-10 (lines 6-19)

BC Hydro concludes at lines 11-12 that "a customer's coincident peak demand is a major consideration in segmenting customer classes". However, at lines 17-19, BC Hydro also concludes that "since distribution costs are assigned proportionate to NCP, the cost per NCP kW does not vary and a $/kW analysis cannot be used to identify cost differences between segments".

1.52.2 Please explain why a customer's coincident peak demand is considered a major consideration in segmenting classes but a customer's contribution to NCP cannot be used.

RESPONSE:

More than 30 per cent of the revenue requirement costs are generation and transmission demand-related, which are allocated using 4CP.

Rate class NCP is used to assign Distribution demand-related costs, which account for 14 per cent of the total F2016 revenue requirement. A customer's contribution to a segment's NCP could be used to allocate Distribution demand-related costs within the rate class; however, this was not the approach taken with the methodology. Costs were assigned to each segment using the segment NCP. The individual customer contributions to each segment's NCP was not a part of the data used for this portion of the segmentation analysis.

53.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, page 4-12

1.53.1 With respect to Figure 4-2 please clarify whether the coincident demand costs for each group are divided by a) the NCP for the group or b) the sum of the maximum monthly demands for each customer in the group (i.e., total billing demand for the group).

RESPONSE:

In Figure 4-2 of Exhibit B-1, the demand cost is divided by the NCP for the segment. The sum of the maximum monthly demands for customers in the segment was determined to overlook the diversity of the segment in assigning costs associated with a coincident peak. (Non-coincident peak is non-coincident with the system peak but coincident within the class.)

53.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, page 4-12

1.53.1 With respect to Figure 4-2 please clarify whether the coincident demand costs for each group are divided by a) the NCP for the group or b) the sum of the maximum monthly demands for each customer in the group (i.e., total billing demand for the group).

1.53.1.1 If NCP was used, please explain why this appropriate/relevant for segmentation purposes.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.53.1.

53.0 CHAPTER 4 RATE CLASS DETERMINATION

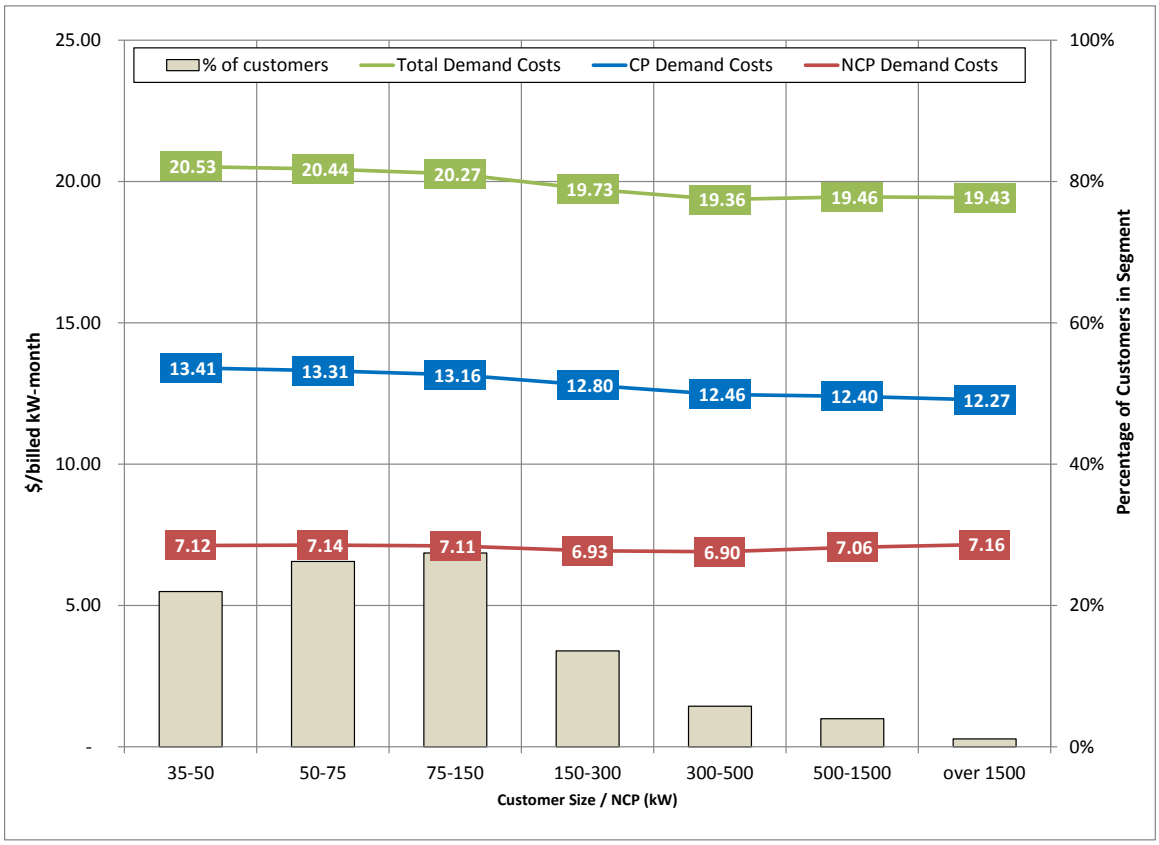
Reference: Exhibit B-1, page 4-12

1.53.1 With respect to Figure 4-2 please clarify whether the coincident demand costs for each group are divided by a) the NCP for the group or b) the sum of the maximum monthly demands for each customer in the group (i.e., total billing demand for the group).

1.53.1.2 If NCP was used, please re-do Figure 4-2 where the coincident demand costs for each group are divided by the billing demand for the group (i.e. the sum of the peak demands of the individual customers).

RESPONSE:

Figure 4-2 of Exhibit B-1 has been reproduced below using the annual sum of monthly customer peak demands divided by 12 as the denominator and demand costs in the numerator as indicated in the chart legend to determine an annualized $/billed-kW cost.



53.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, page 4-12

1.53.2 Please provide a figure, similar to Figure 4-2 where the Distribution-demand related costs that would be allocated to each segment are divided by the billing demand for the group.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.53.1.2.

53.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, page 4-12

1.53.3 Please provide a figure, similar to Figure 4-2, where the sum of the Generation-related demand costs, Transmission costs and Distribution-related demand costs that would be allocated to each group is divided by the billing demand for the group.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.53.1.2.

54.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, page 4-18 and Appendix C-5A, page 137 of 292

1.54.1 With respect to the analysis presented in Workshop 5 (lines 20-24), please clarify how the load factor was determined for each customer and, in particular, what was used as the denominator in the calculation (e.g. was it the individual customer's average maximum monthly demand?).

RESPONSE:

BC Hydro calculates annual load factor as total annual energy (numerator) divided by the product of annual peak demand (denominator) and annual hours (denominator).

55.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, page 4-19 and Appendix C-1B, page 40 of 115

1.55.1 Please provide a revised version of the table at slide 40 that indicates for each of the 15 segments, the percentage of total energy purchases that were Tier 2 purchases.

RESPONSE:

The table below shows the estimated share of F2014 RS 1823 energy purchases that were Tier 2 from each of the major industries identified on slide 40 of the Workshop 12 presentation (i.e., Forestry, Mining, Oil and Gas, Ports and Pipelines).

Customers one to thirteen in the table on slide 40 have been included in this analysis but the proportion of their total individual purchases, that is Tier 2 energy, has not been provided for confidentiality reasons. Note that customers without RS 1823 CBLs (including New Westminster and FortisBC) were excluded from this high level analysis.

	Estimated Share of Total F2014 RS 1823 Sales that are Tier 2 (%)
Forestry	**4**
Mining	**1**
Oil & Gas	**11**
Ports	**12**
Pipelines	**0**

56.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, pages 4-26

1.56.1 BC Hydro notes that the nature of the service is similar as between RS 1702, RS 1703 and RS 1704. However for RS 1703 BC Hydro owns the pole whereas for the other two rate schedules it does not. Does BC Hydro plan to account for this difference in its examination of street lighting rate design as part of RDA Module 2?

RESPONSE:

Yes, RS 1703 contains a Pole Contact Charge to recover the costs associated with customers placing their lighting fixtures on BC Hydro-owned poles. BC Hydro will review the charge in RDA Module 2.

56.0 CHAPTER 4 RATE CLASS DETERMINATION

Reference: Exhibit B-1, pages 4-26

1.56.2 Will BC Hydro take into account in considering the creation of two street lighting customer classes the fact that some customers currently on RS 1755 own the pole whereas in other cases they do not?

RESPONSE:

Yes, BC Hydro will take into account the difference in pole ownership.

As noted in Table 4-5 on page 4-25 of Exhibit B-1 the RS 1755 accounts for about $1 million of revenue whereas the RS 1701 rate accounts for about $18 million in revenue.

Therefore, the pole ownership of RS 1755 customers will have a small impact on COS results and is of secondary importance when deciding whether to create separate rate classes for BC Hydro-owned and customer-owned street lights.

57.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-3

1.57.1 Please provide a schedule that sets out the MWh of conservation delivered by the RIB rate in each of the years up to (and including) F2015.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.37.2.

58.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-5

1.58.1 With respect to lines 8-12, how were the Step 1 and basic charge jointly set so as to achieve revenue neutrality?

RESPONSE:

Per Commission Order No. G-124-08:

- **The October 1, 2008 basic charge at the inception of the RIB rate was priced by increasing the basic charge as set on April 1, 2007 by inflation of 2.1 per cent; and**
- **The October 1, 2008 Step 1 rate was set residually to achieve revenue neutrality.**

58.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-5

1.58.2 Please provide a schedule that sets out the monthly usage by Residential customers (overall) broken down by each 10th percentile of increasing customer use. (i.e., what is the monthly usage below which 10% of customers fall, 20% of customers fall on up to 90% and then 100%).

RESPONSE:

BC Hydro cannot provide the requested monthly usage breakdown in the time allotted to respond. For example, the billing cycle is bi-monthly, and it would require significant data manipulation and modelling. To be responsive BC Hydro estimates the following annual consumption based on 2014 REUS:

All Residential Accounts, F2015	
Percentiles	Annual Consumption (kWh)
10	2,556
20	3,821
30	5,063
40	6,236
50	7,454
60	8,769
70	10,575
80	12,742
90	16,392
100	160,885

58.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-5

1.58.3 Please provide a similar schedule to that in part (2) but for low income customers.

RESPONSE:

BC Hydro cannot provide the requested monthly usage breakdown in the time allotted to respond for the reasons set out in BC Hydro's response to BCOAPO IR 1.58.2. To be responsive BC Hydro estimates the following annual consumption based on the 2014 REUS:

Low Income Accounts, F2015	
Percentiles	Annual Consumption (kWh)
10	1,714
20	2,618
30	3,374
40	4,253
50	5,298
60	6,437
70	8,183
80	10,012
90	13,593
100	44,884

59.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-10 to 5-12

1.59.1 Please explain why all of the consumption statistics quoted are based on median use as opposed to average use.

RESPONSE:

The median has been used consistently as a key statistic in all previous applications concerning the RIB rate, including the decision in the setting of the Step 1/Step 2 energy threshold in the 2008 RIB Application (Commission 2008 RIB Decision, page 107).

BC Hydro continues to be of the view that, the median, rather than the mean, is the appropriate statistic for rate design, modelling and analysis purposes. Statistically, the median is preferred over the mean in the analysis of residential consumption because the distribution of consumption is skewed. Using the median in analysis avoids biases towards the extreme customers.

59.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-10 to 5-12

1.59.1 Please explain why all of the consumption statistics quoted are based on median use as opposed to average use.

1.59.1.1 In each case where the median value is quoted please provide the average value as well.

RESPONSE:

In the context of providing details concerning Residential customer characteristics described at pages 5-10 to 5-12 of Exhibit B-1, per the reference of this IR, BC Hydro will provide the requested descriptive statistics for purposes of responding to BCOAPO IRs 1.59.2 to 1.59.6.

59.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-10 to 5-12

1.59.2 Please provide a schedule that set outs out the average and median consumption by dwelling type.

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates the following:

Dwelling Collapse - Main	F2015 Mean kWh
Single detached house	11263
Duplex/Row/Town	8192
Apartment/condominium	4418
Mobile/other	8918
Total	8843

Dwelling Collapse - Main	F2015 Median kWh
Single detached house	9807
Duplex/Row/Town	7636
Apartment/condominium	3699
Mobile/other	8323
Total	7454

59.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-10 to 5-12

1.59.3 Please provide schedules that set for each of the regions:

(a) The number of accounts by dwelling type;
(b) The total consumption by dwelling type; and
(c) The median and average use by dwelling type.

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates the following:

a)

Dwelling Type (# of accounts)	Region			
	Lower Mainland	Island	South	North
Single detached house	454,542	219,493	126,487	94,475
Duplex/Row/Town	153,411	34,837	19,337	9,106
Apartment/ condominium	349,157	72,633	22,977	14,570
Mobile/other	12,746	22,314	24,569	20,261

b) and c)

Region	Dwelling Type	Total Consumption (kWh)	Mean Consumption (kWh)	Median Consumption (kWh)
Lower Mainland	Single detached house	4,967,842,651	10,929	9,258
	Duplex/Row/Town	1,229,469,762	8,014	7,486
	Apartment/condominium	1,503,010,701	4,305	3,596
	Mobile/other	102,673,867	8,055	8,368
Island	Single detached house	2,809,797,448	12,801	12,063
	Duplex/Row/Town	330,296,079	9,481	9,116
	Apartment/condominium	339,008,137	4,667	3,874
	Mobile/other	206,185,738	9,240	8,793
South	Single detached house	1,367,444,436	10,811	9,394
	Duplex/Row/Town	142,724,917	7,381	6,936
	Apartment/condominium	120,014,842	5,223	4,915
	Mobile/other	205,541,096	8,366	7,467
North	Single detached house	934,994,938	9,897	8,816
	Duplex/Row/Town	73,690,839	8,093	6,929
	Apartment/condominium	67,413,249	4,627	4,270
	Mobile/other	198,058,454	9,775	8,756

59.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-10 to 5-12

1.59.4 Please provide a schedule that sets the median and average per account for dwellings with electric heating vs. non-electric heating.

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates the following:

Annual Consumption (kWh), F2015		
	Mean	Median
Electricity	9,938	8,184
Non-Electric	8,055	7,078
Not Applicable (No Home Heating)	1,980	1,780
Total	8,844	7,454

59.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-10 to 5-12

1.59.5 Please provide schedules that set out for each region:

(a) The number of accounts with electric heating vs. non-electric heating;
(b) The consumption of the accounts with electric heating vs. non-electric heating; and
(c) The median and average use per dwelling for accounts with electric heating vs. non-electric heating.

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates the following:

a)

Heating Type (# of accounts)	Region			
	Lower Mainland	Island	South	North
Electricity	390,219	224,128	54,891	31,137
Non-Electric	578,726	124,465	137,568	107,048
Not applicable - no home heating	911	683	911	227

b) and c)

Region	Heating Type	Total Consumption (kWh)	Mean Consumption (kWh)	Median Consumption (kWh)
Lower Mainland	Electricity	3,304,725,505	8,469	6,251
	Non-Electric	4,502,566,819	7,780	6,692
	Not applicable - no home heating	1,620,699	1,780	1,780
Island	Electricity	2,674,158,741	11,931	11,241
	Non-Electric	1,010,087,815	8,115	7,582
	Not applicable - no home heating	584,251	856	1,202
South	Electricity	645,211,071	11,754	10,095
	Non-Electric	1,184,922,791	8,613	7,602
	Not applicable - no home heating	2,887,244	3,169	2,988
North	Electricity	336,867,188	10,819	9,408
	Non-Electric	937,006,364	8,753	7,989
	Not applicable - no home heating	268,031	1,179	

59.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-10 to 5-12

1.59.6 For each region, by dwelling type please provide schedules that set out:

(a) The number of accounts with electric heating vs. non-electric heating;
(b) The consumption of the accounts with electric heating vs. non-electric heating; and
(c) The median and average use per dwelling for accounts with electric heating vs. non-electric heating.

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates the following:

a)

Dwelling Type (# of accounts)	Heating Type	Region			
		Lower Mainland	Island	South	North
Single detached house	Electricity	79,209	130,104	30,939	16,163
	Non-Electric	375,333	89,162	95,320	78,312
	Not applicable - no home heating	0	227	227	0
Duplex/Row/Town	Electricity	68,056	24,590	5,460	2,277
	Non-Electric	85,355	10,246	13,877	6,830
Apartment/condominium	Electricity	239,676	58,061	14,332	10,311
	Non-Electric	109,482	14,572	8,645	4,259
Mobile/other	Electricity	3,187	11,384	4,322	2,072
	Non-Electric	8,649	10,474	19,564	17,959
	Not applicable - no home heating	910	455	682	230

b) and c)

Region	Dwelling Type	Heating Type	Total Consumption (kWh)	Mean Consumption (kWh)	Median Consumption (kWh)
Lower Mainland	Single detached house	Electricity	1,363,347,154	17,212	13,996
		Non-Electric	3,590,913,981	9,567	8,275
	Duplex/Row/Town	Electricity	724,568,509	10,647	9,971
		Non-Electric	510,974,757	5,986	5,553
	Apartment/condominium	Electricity	1,163,031,170	4,853	4,225
		Non-Electric	339,979,532	3,105	2,624
	Mobile/other	Electricity	39,725,538	12,467	12,171
		Non-Electric	63,879,953	7,386	7,272
		Not applicable - no home heating	1,620,319	1,780	1,780
Island	Single detached house	Electricity	1,983,060,306	15,242	14,376
		Non-Electric	825,571,557	9,259	8,528
		Not applicable - no home heating	1	0	0
	Duplex/Row/Town	Electricity	269,005,478	10,939	10,634
		Non-Electric	61,376,793	5,990	5,000
	Apartment/condominium	Electricity	295,192,900	5,084	4,433
		Non-Electric	43,815,237	3,007	2,548
	Mobile/other	Electricity	125,293,044	11,006	10,602
		Non-Electric	79,037,923	7,546	6,894
		Not applicable - no home heating	745,567	1,637	1,637
South	Single detached house	Electricity	466,318,978	15,072	13,954
		Non-Electric	900,603,672	9,448	8,470
		Not applicable - no home heating	188,360	828	
	Duplex/Row/Town	Electricity	51,565,336	9,444	9,260
		Non-Electric	91,820,264	6,617	6,435
	Apartment/condominium	Electricity	84,917,657	5,925	5,902
		Non-Electric	35,097,185	4,060	3,571
	Mobile/other	Electricity	44,283,745	10,245	9,566
		Non-Electric	157,814,690	8,066	7,355
		Not applicable - no home heating	2,887,515	4,231	5,433
North	Single detached house	Electricity	231,571,052	14,327	13,567
		Non-Electric	703,890,359	8,988	8,174
	Duplex/Row/Town	Electricity	28,364,157	12,459	12,416
		Non-Electric	44,430,358	6,506	6,252
	Apartment/condominium	Electricity	51,847,933	5,028	4,743
		Non-Electric	15,565,316	3,655	3,320
	Mobile/other	Electricity	22,154,602	10,692	10,788
		Non-Electric	175,669,655	9,782	8,751
		Not applicable - no home heating	271,522	1,179	

60.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-12 to 5-14

Each of the following questions refers solely to low income Residential accounts.

1.60.1 Please provide a schedule that sets out a breakdown of the number of low income customers by region, the consumption of low income customers by region and the resulting median and average use by region.

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates the following:

Region	Number of Accounts	Total Consumption (kWh)	Mean Consumption (kWh)	Median Consumption (kWh)
Lower Mainland	109,937	703,427,351	6,398	5,100
Island	26,640	182,713,355	6,859	5,558
South	12,740	98,544,228	7,735	7,172
North	12,066	91,843,801	7,612	6,088

60.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-12 to 5-14

Each of the following questions refers solely to low income Residential accounts.

1.60.2 Please provide a schedule that set outs out the average and median consumption by dwelling type for low income customers.

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates the following:

Dwelling Type	Mean Consumption (kWh)	Median Consumption (kWh)
Single detached house	9,969	8,797
Duplex/Row/Town	7,956	6,476
Apartment/condominium	4,067	3,515
Mobile/other	8,227	8,235

60.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-12 to 5-14

Each of the following questions refers solely to low income Residential accounts.

1.60.3 Please provide schedules that set out the following for low income customers for each of the regions:

(a) The number of accounts by dwelling type;

(b) The consumption by dwelling type; and

(c) The median and average use by dwelling type.

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates the following:

a)

		Region			
		Lower Mainland	Island	South	North
Dwelling Type (# of accounts)	Single detached house	36,190	8,425	5,327	5,236
	Duplex/Row/Town	14,112	4,098	1,853	1,138
	Apartment/condominium	57,358	12,523	3,243	3,187
	Mobile/other	2,276	1,594	2,316	2,504

b) and c)

Region	Dwelling Type	Total Consumption (kWh)	Mean Consumption (kWh)	Median Consumption (kWh)
Lower Mainland	Single detached house	347,485,082	9601.594	9325.004
	Duplex/Row/Town	111,027,560	7867.620	6438.568
	Apartment/condominium	238,766,758	4162.724	3579.807
	Mobile/other	19,279,342	8470.255	7442.925
Island	Single detached house	94,649,372	11234.988	8268.517
	Duplex/Row/Town	36,834,093	8987.400	8050.704
	Apartment/condominium	47,867,231	3822.366	3223.734
	Mobile/other	12,181,118	7642.681	7873.719
South	Single detached house	55,933,833	10499.080	10271.417
	Duplex/Row/Town	12,318,747	6647.847	6101.031
	Apartment/condominium	12,294,011	3791.142	2930.518
	Mobile/other	19,772,118	8536.064	8998.401
North	Single detached house	51,737,715	9881.190	7961.112
	Duplex/Row/Town	9,010,997	7916.490	7186.397
	Apartment/condominium	11,805,124	3704.012	3321.979
	Mobile/other	20,391,437	8143.010	8314.022

60.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-12 to 5-14

Each of the following questions refers solely to low income Residential accounts.

1.60.4 Please provide a schedule that for low income customers sets the median and average per account for dwellings with electric heating vs. non-electric heating.

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates the following:

Heating Type	Mean Consumption (kWh)	Median Consumption (kWh)
Electricity	6,477	4,966
Non-Electric	6,889	5,683

60.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-12 to 5-14

Each of the following questions refers solely to low income Residential accounts.

1.60.5 Please provide schedules that for low income customers set out for each region:

(a) The number of accounts with electric heating vs. non-electric heating;
(b) The consumption of the accounts with electric heating vs. non-electric heating; and
(c) The median and average use per dwelling for accounts with electric heating vs. non-electric heating.

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates the following:

a)

(# of accounts)		Region			
		Lower Mainland	Island	South	North
Heating Type	Electricity	57,021	18,964	4,322	3,870
	Non-Electric	52,916	7,676	8,417	8,195

b) and c)

Region	Heating Type	Total Consumption (kWh)	Mean Consumption (kWh)	Median Consumption (kWh)
Lower Mainland	Electricity	349,292,741	6,126	4,906
	Non-Electric	354,179,216	6,693	5,314
Island	Electricity	133,877,512	7,060	6,027
	Non-Electric	48,924,339	6,374	4,817
South	Electricity	39,994,802	9,253	8,742
	Non-Electric	58,721,183	6,976	6,444
North	Electricity	22,127,505	5,718	4,453
	Non-Electric	71,842,850	8,766	7,307

60.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-12 to 5-14

Each of the following questions refers solely to low income Residential accounts.

1.60.6 For each region, by dwelling type please provide schedules that for low income customers set out:

(a) The number of accounts with electric heating vs. non-electric heating,
(b) The consumption of the accounts with electric heating vs. non-electric heating, and
(c) The median and average use per dwelling for accounts with electric heating vs. non-electric heating.

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates the following:

a)

Dwelling Type (# of accounts)	Heating Type	Region			
		Lower Mainland	Island	South	North
Single detached house	Electricity	5,463	5,237	1,390	1,138
	Non-Electric	30,728	3,188	3,938	4,098
Duplex/Row/Town	Electricity	8,560	2,732	695	455
	Non-Electric	5,552	1,366	1,158	683
Apartment/ condominium	Electricity	42,563	10,018	2,085	1,912
	Non-Electric	14,795	2,505	1,158	1,275
Mobile/other	Electricity	455	911	232	455
	Non-Electric	1,821	683	2,085	2,049

b) and c)

Region	Dwelling Type	Heating Type	Total Consumption (kWh)	Mean Consumption (kWh)	Median Consumption (kWh)
Lower Mainland	Single detached house	Electricity	70,806,345	12,962	11,904
		Non-Electric	274,648,717	8,938	8,330
	Duplex/Row/Town	Electricity	80,295,712	9,381	9,381
		Non-Electric	32,356,384	5,828	4,421
	Apartment/condominium	Electricity	190,146,901	4,467	3,821
		Non-Electric	50,347,803	3,403	3,026
	Mobile/other	Electricity	6,743,261	14,813	14,813
		Non-Electric	11,930,085	6,552	3,287
Island	Single detached house	Electricity	62,221,612	11,881	8,484
		Non-Electric	32,996,678	10,351	7,796
	Duplex/Row/Town	Electricity	28,422,400	10,402	9,852
		Non-Electric	6,184,840	4,527	4,163
	Apartment/condominium	Electricity	41,597,319	4,152	3,647
		Non-Electric	6,667,098	2,662	2,561
	Mobile/other	Electricity	7,394,315	8,119	8,762
		Non-Electric	4,744,142	6,945	6,366
South	Single detached house	Electricity	20,940,062	15,067	15,308
		Non-Electric	34,617,292	8,791	8,291
	Duplex/Row/Town	Electricity	6,376,835	9,177	9,944
		Non-Electric	6,453,751	5,572	5,900
	Apartment/condominium	Electricity	9,017,207	4,325	2,811
		Non-Electric	3,551,072	3,066	3,061
	Mobile/other	Electricity	3,198,372	13,808	16,193
		Non-Electric	15,659,879	7,512	7,941
North	Single detached house	Electricity	9,442,152	8,295	12,050
		Non-Electric	42,077,878	10,269	7,817
	Duplex/Row/Town	Electricity	4,365,098	9,587	15,056
		Non-Electric	4,809,752	7,043	7,179
	Apartment/condominium	Electricity	7,511,650	3,928	3,699
		Non-Electric	3,252,111	2,551	2,630
	Mobile/other	Electricity	3,612,252	7,934	10,727
		Non-Electric	16,759,943	8,180	8,314

61.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-17 and Appendix C-3B, page 132 of 609

1.61.1 If customers with bi-monthly use of 1,350 to 2,400 kWh have a Step 2 price elasticity of -0.13 and customers over 2,400 kWh have a Step 2 price elasticity of -0.16 to -0.18, then how can the overall Step 2 price elasticity be in the range of -0.08 to -0.13?

RESPONSE:

The same three econometric models were used to estimate the range of RIB rate Step 2 price elasticity for the two Step 2 sub-groups and for the overall Step 2 group.

One of the models (model 3) produced a Step 2 price elasticity for the smaller sub-group near the lower end of the range for the overall group (-0.07); however it was not statistically significant. Nevertheless, this result provides some evidence that the lower end of the range of price elasticity for the smaller sub-group is below -0.13.

This result from model 3 may be due to the fact that a greater proportion of the smaller sub-group's consumption occurs in Step 1 (below 1,350 kWh) than the larger sub-group or the overall group. As a result, the Step 2 price signal may not be as strong for the smaller sub-group as it is for the other groups.

Note also that while the same three models were used in all analyses, the analysis captured different groups. The characteristics of the overall group may be different than the characteristics of each sub-group.

In preparing this IR response, BC Hydro discovered a typographical error in the 2013 RIB Evaluation Report. The corrected section is provided below, with new text marked with an underline and deleted text marked with a strikethrough.

Section 3.3.4 Price Elasticity by Consumption Level (Exhibit B-1, Appendix C-3B, page 132 of 609):

The results in Table 3.9 indicate that the customer segment above 2400 kWh has an estimated price elasticity of -0.16 to -0.18, and the price elasticity of the customer segment between 1350 kWh and 2400 kWh ~~ranges from -0.07 to~~ <u>was</u> -0.13. These results are consistent with the RIB design assumptions that customers with a higher level of consumption tend to have a higher responsiveness to price.

Table 0.1. Step 2 Price Elasticity by Consumption Level

Econometric Model	0-400kWh	400 kWh – 900 kWh	900 kWh – 1350 kWh	1350 kWh –2400 kWh	2400 kWh and above
1	N/A	N/A	N/A	-0.13	-0.18
2	N/A	N/A	N/A	-0.13	-0.18
3	N/A	N/A	N/A	~~-0.13~~ N/A	-0.16

62.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

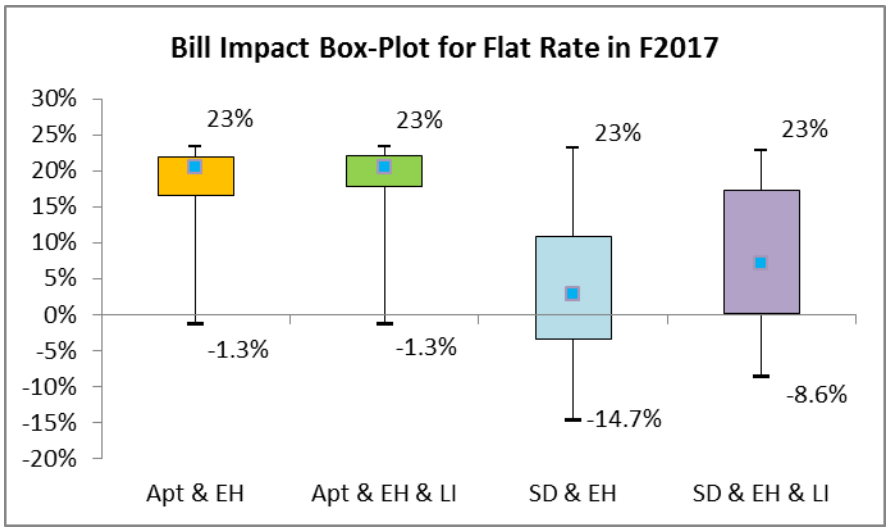
Reference: Exhibit B-1, pages 5-24 – 5-25

1.62.1 Please provide a plot similar to Figure 5-14 for each of the following (total as well as by region if practical):

(a) Apt & Electric Heat;
(b) Apt. & Electric Heat & LI;
(c) Single Detached & Electric Heat; and
(d) Single Detached & Electric Heat & LI.

RESPONSE:

Using the same vintage of assumptions as in Exhibit B-1, Figure 5-14, the outcomes are as follows:



62.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-24 – 5-25

1.62.2 Please provide Tables similar to 5-3 and 5-4 for each of the results set out in part (1).

RESPONSE:

Using the same vintage of modelling assumptions for the flat rate illustrated at Exhibit B-1, Tables 5-3 and 5-4, the tables below are reproduced for BC Hydro's response.

Account Segments	Proportion Higher than 10% BI (%)	Proportion Higher than 20% BI (%)
Apt & Electric Heat	93	58
Apt & Electric Heat & LI	95	62
SFD & Electric Heat	23	6
SFD & Electric Heat & LI	33	8

Account Segments	Proportion Better off than SQ (%)	Median Bill of Segment ($)	Median Bill Difference from SQ ($)
Apt & Electric Heat	1	529	79
Apt & Electric Heat & LI	2	458	67
SFD & Electric Heat	58	1,557	-5
SFD & Electric Heat & LI	39	1,260	60

63.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-26 to 5-27

1.63.1 Which participants did not support only advancing Three Step A for purposes of the RDA?

RESPONSE:

The reference to this question is BC Hydro's statement on page 5-26, lines 8-9, of Exhibit B-1 that "Most participants agreed that only Three-Step A should be advanced for the 2015 RDA, and that Three-Step A was inferior to the RIB rate."

BCOAPO was the only participant that appeared to not directly support only advancing Three-Step A for purposes of the RDA. BCOAPO stated its belief that there is both scope and rationale for supporting a rate design with both a Step 2 and higher Step 3 rate as being cost-based. By definition, such a three-step rate model would be different than Three-Step A, which calculates the Step 3 rate residually, but possibly similar to Three-Step C, which BC Hydro modelled at the request of BCOAPO, with a Step 3 rate set on the basis of the unit energy cost of greenfield IPPs with other cost adders (refer to Table 5-5 on page 5-26 of Exhibit B-1).

63.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-26 to 5-27

1.63.2 Which participants' comments were given the most weight in determining what alternatives should be advanced to the 2015 RDA and why?

RESPONSE:

As described on page 2-18 of Exhibit B-1, BC Hydro considered all participant input to develop alternatives and/or narrow the number of alternatives brought forward for additional analysis. Where participant feedback conflicted BC Hydro gave more weight to the views of customers or their representatives who take service under the particular rates being assessed except on issues where there could be cost implications for other rate classes. For example, BC Hydro modelled two alternative three-step rates under specific assumptions and objectives at the request of BCOAPO.

63.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-26 to 5-27

1.63.3 Does BC Hydro consider the Energy LRMC (Upper Limit) plus the UCC of Revelstoke 6 to be the relevant maximum value for LRMC for purposes of the 2015 RDA for all customer classes? If not, what is the maximum value for each class and why?

RESPONSE:

If a generation capacity value is to be included in the energy LRMC, it should be based on the avoided cost of the next most cost-effective generation capacity resource, which is the Rev 6 UCC. It is not BC Hydro's position, however, that the energy LRMC plus this generation capacity value is relevant for all proposed default rate designs. For example, the SGS, MGS and LGS flat energy rate proposals are dictated by embedded costs. Please refer to BC Hydro's responses to BCUC IRs 1.11.1 (SGS, MGS and LGS) and 1.13.1 (RIB rate).

63.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-26 to 5-27

1.63.4 Please provide separate versions of Figure 5-16 that just include:

(a) Low Income Customers
(b) Low Income Customers with Electric Heat

RESPONSE:

Exhibit B-1, Figure 5-16 is illustrative and shows the relationship between consumption and bill impacts. It is the same curve for all segments of the population. The indicator bars show where the typical customers for the various segments are, relative to consumption, and is indicative of the bill impacts that will likely be experienced.

The full bill impact distribution is shown in detail in Exhibit B-1, Figure 5-17, in box plots on top of "LI" for low income and "LI & Elec Heat" for low income x electric heat.

64.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-31

1.64.1 What percentage of low income customers with electric heat are better off under the Three Step A alternative as compared to the existing RIB rate?

RESPONSE:

Please refer to Exhibit B-1, Table 5-6 on page 5-28.

65.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-34 to 5-35 and page 5-30

Page 5-30 provides an assessment of Option 1 against the Bonbright criteria based on expected F2017 rates.

1.65.1 Based on the anticipated rates for F2018 and F2019 please provide a comparative analysis of Options 1 and 2 using the Bonbright Criteria.

RESPONSE:

Bonbright Criteria	**Option 1: Proposed RIB Rate – Apply RRA increases equally to all three RIB rate pricing elements**	**Option 2: Apply RRA increases to Step 1 energy rate and basic charge only while holding Step 2 rate at its current level**
	BC Hydro Observation	**BC Hydro Observation**
Economic Efficiency – Price signals that encourage efficient use and discourage inefficient growth	• **The Step 2 rate exceeds the upper end of the energy LRMC range**	• **Step 2 is approximately at energy LRMC upper limit by F2019** • **Differential between Step 1 and Step 2 rates narrows over time** • **Loss of conservation relative to Option 1**
Fairness – Fair apportionment of costs among customers; Avoid undue discrimination	• **The Step 1 / Step 2 threshold is generally reflective of typical Residential customer consumption on an on-going, stable basis;** • **The basic charge recovers about 45 per cent of customer-related costs, which is in line with other jurisdictions**	• **The same as Option 1**

Bonbright Criteria	**Option 1: Proposed RIB Rate – Apply RRA increases equally to all three RIB rate pricing elements**	**Option 2: Apply RRA increases to Step 1 energy rate and basic charge only while holding Step 2 rate at its current level**
	BC Hydro Observation	**BC Hydro Observation**
Practicality – Customer understanding and acceptance, practical and cost-effective to implement; Freedom from controversies as to proper interpretation	• **Option 1 may be more easily understood because the RRA is applied equally to both Step 1 and Step 2.** • **Option 1 is better from the a bill impact perspective for the majority of Residential customers**	• **May be comparatively worse from a customer understanding perspective** • **Increases to the Step 1 rate results in higher bill impacts for most customers, including low income customers**
Stability – Recovery of the revenue requirement; revenue stability; rate stability	• **The RIB rate has been in place since October 2008;** • **The RIB rate is effective in collecting the revenue requirement**	• **The same as Option 1**

66.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-35

1.66.1 Please provide the rates that would result from a 3rd Option (Option 3) where the Step 2 rate is increased at inflation and the Step 1 rate is increased so as to maintain revenue neutrality.

RESPONSE:

Using the inflation assumptions stated in Exhibit B-1, Appendix H-1A, page 1 (2 per cent for F2017, F2018, and F2019), the illustrative rates are as follows:

	F2017	F2018	F2019
Step 1 (cents/kWh)	**8.46**	**8.89**	**9.24**
Step 2 (cents/kWh)	**12.19**	**12.43**	**12.68**
Basic ($/day)	**0.1835**	**0.1899**	**0.1956**

66.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

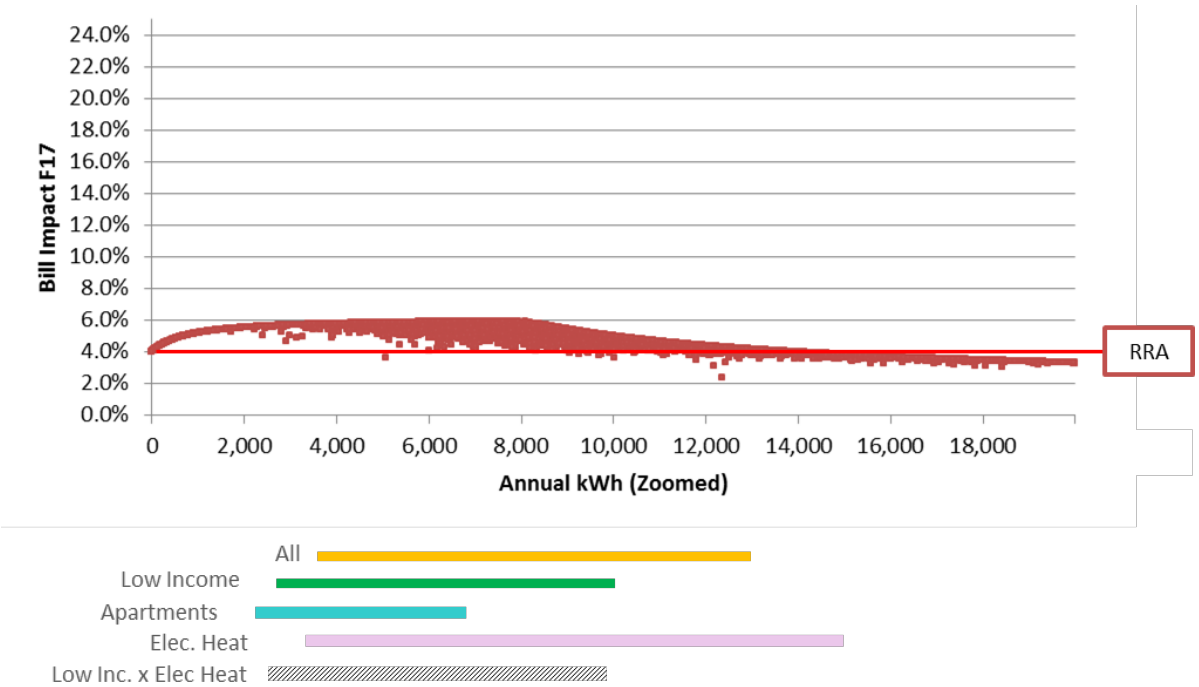
Reference: Exhibit B-1, page 5-35

1.66.2 Please provide the equivalent to Figures 5-20 through 5-24 and Tables 5-9 & 5-10 based on this option.

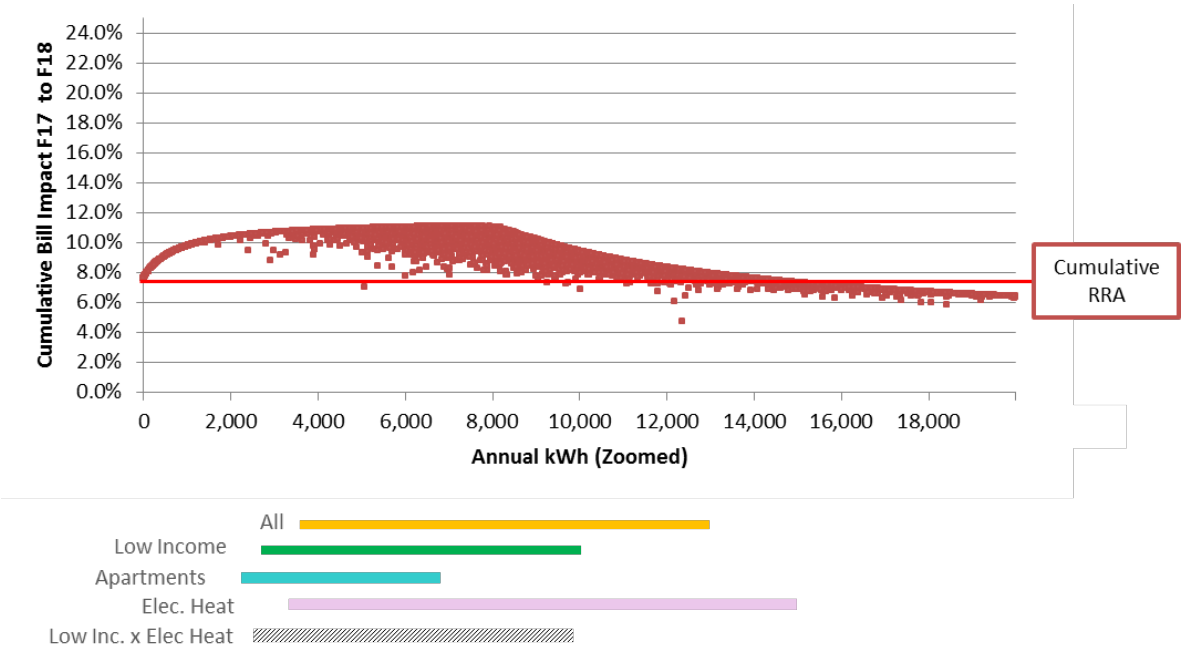
RESPONSE:

Using the same vintage of modelling assumptions for Exhibit B-1, Figures 5-20 through 5-24, Table 5-9 and Table 5-10, the figures and tables are reproduced for the "BCOAPO Option 3" rates shown in BC Hydro's response to BCOAPO IR 1.66.1:

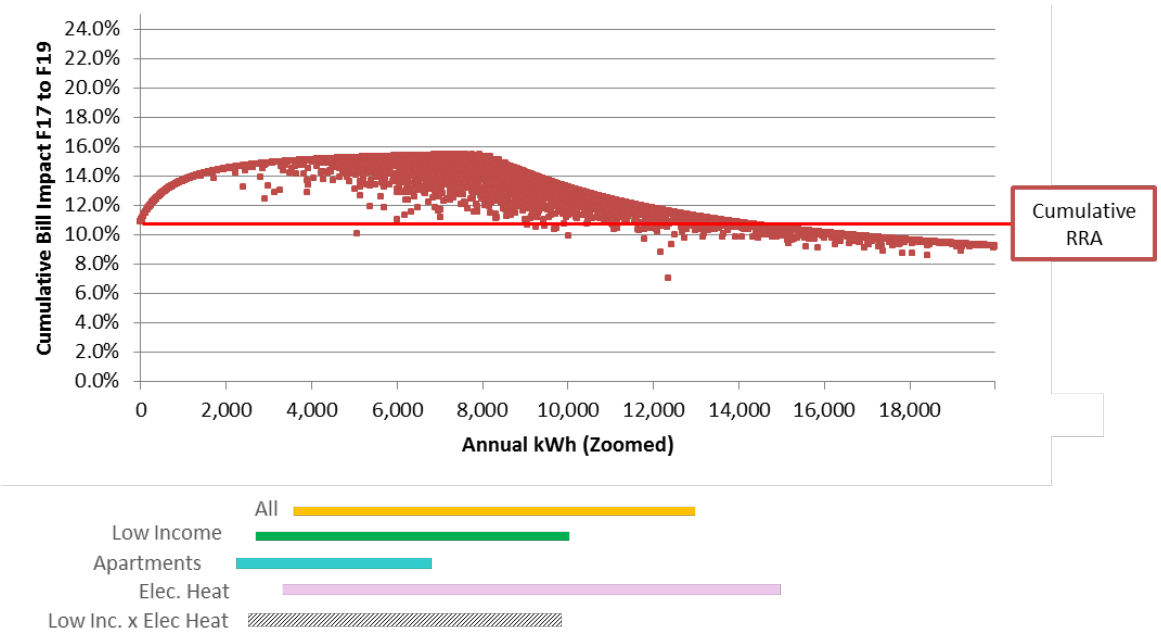
Bill Impact vs Annual consumption for "BCOAPO Option 3" in F2017

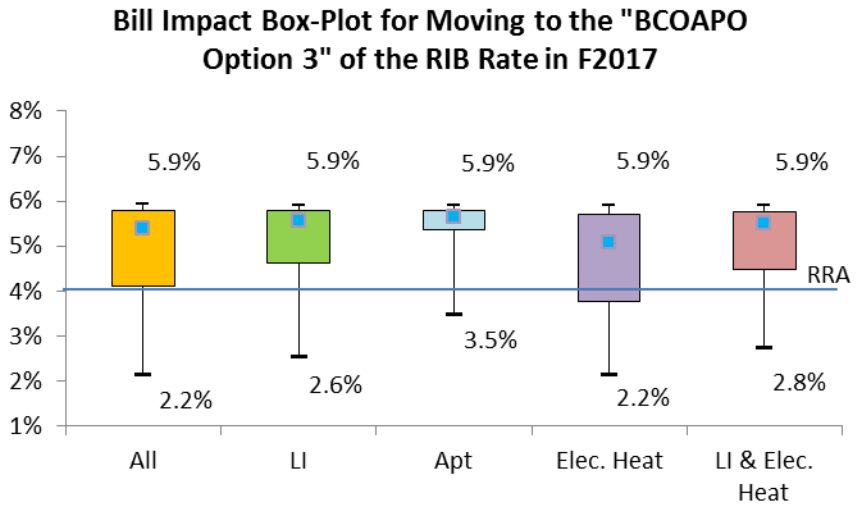


Cumulative Bill Impact vs Annual consumption for "BCOAPO Option 3" in F2018



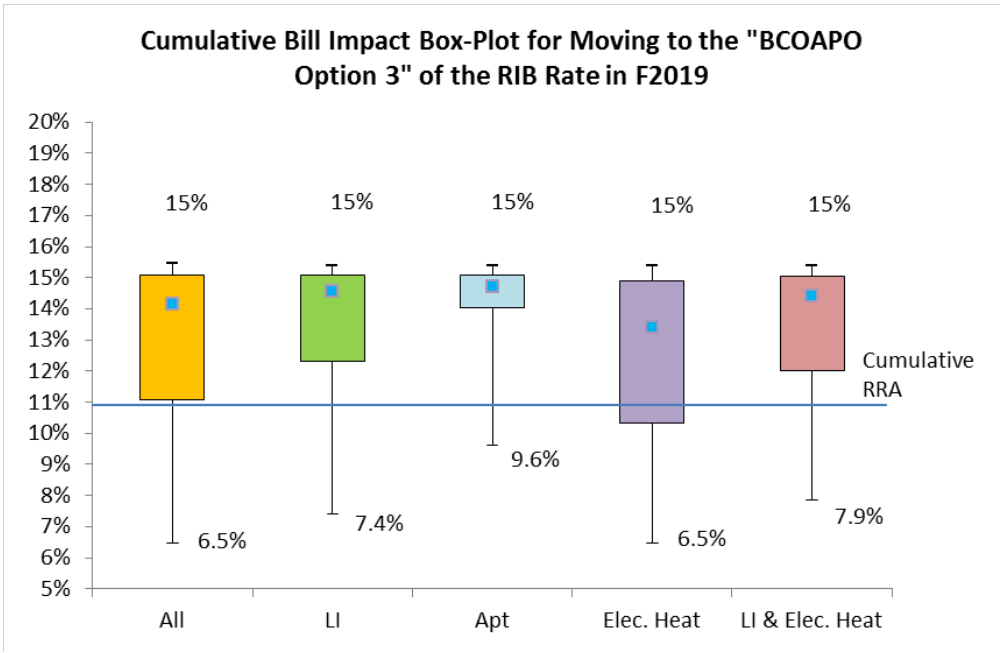
Cumulative Bill Impact vs Annual consumption for "BCOAPO Option 3" in F2019





Bill Characteristics for moving to "BCOAPO Option 3" in F2017

Account Segments	Proportion Better off than SQ (%)	Median Bill of Segment ($)	Median Bill Difference from SQ ($)
All Customers	24	751	11
Low Income	15	541	9
Apartment	2	399	7
Electric Heat	33	843	10
LI & Electric Heat	16	511	9



Bill Characteristics for moving to "BCOAPO Option 3" in F2019

Account Segments	Proportion Better off than SQ (%)	Median Bill of Segment ($)	Median Bill Difference from SQ ($)
All Customers	21	816	27
Low Income	13	589	22
Apartment	2	434	16
Electric Heat	30	911	23
LI & Electric Heat	13	557	21

67.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-41 to 5-42 and Appendix C-3B, page 29 of 609

1.67.1 What percentage of customer-related costs did the Residential basic charge recover at the time of the last RDA?

RESPONSE:

In F2008, the Residential basic charge recovered approximately 35 per cent of customer-related costs.

67.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-41 to 5-42 and Appendix C-3B, page 29 of 609

1.67.2 Please clarify what is meant by customer-related costs and indicate what the dollar value for customer-related costs is for the Residential class based on the F2016 COSS, providing the necessary cross-references to the F2016 COSS – per Appendix E.

RESPONSE:

Customer-related costs are comprised of:

- **Distribution cost that have been classified as customer-related, that is, metering, services and a portion of transformer costs; and**
- **Customer care-related costs, that is, billing and call center costs, etc.**

Total customer-related costs assigned to the Residential class in the F2016 COS Study are $273.4 million, as computed in cell H4 of Schedule 4.1 in Appendix E of Exhibit B-1.

Specific references to the classification and allocation of the components of customer-related costs as assigned to the Residential class can be traced back through the F2016 COS model from cell H4 of Schedule 4.1.

67.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-41 to 5-42 and Appendix C-3B, page 29 of 609

1.67.3 Based on the F2016 Residential billing determinants (i.e., customers and energy) please provide the calculations demonstrating that the current F2016 basic charge recovers 45% of customer-related costs.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.42.2.

67.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-41 to 5-42 and Appendix C-3B, page 29 of 609

1.67.4 It is noted that Slide 28 from Workshop 9a uses the term "fixed cost" as opposed to "customer-related costs". What is the definition of fixed costs used in this context, is it the same as BC Hydro's definition of customer-related costs and, if so, how has BC Hydro ensured the definitions are comparable?

RESPONSE:

The heading in the table on slide 28 of the Workshop 9a presentation summarizing BC Hydro's Canadian jurisdictional review should have referred to customer-related costs.

As part of section 3.2 of the Workshop 11a/11b consideration memo, in response to feedback from BCOAPO, BC Hydro confirmed that its prior references in 2015 RDA engagement materials to SGS basic charge and RIB rate basic charge fixed cost recovery should properly refer instead to customer-related cost recovery. BC Hydro also noted that all referred-to percentages and modelling results are correct in reference to customer-related cost recovery; the SGS and RIB basic charges do not recover any demand-related costs (refer to page 171 of 382 of Appendix C-4B of Exhibit B-1).

The definition of customer-related costs is provided in BC Hydro's response to BCOAPO IR 1.67.2.

68.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-42 to 5-43

1.68.1 Please provide, with reference to the COSS in Appendix E, the calculation indicating $15 is roughly equivalent to the average fixed distribution and customer-related cost per month.

RESPONSE:

A $15 per month minimum charge is roughly equivalent to:

Total customer-related costs ($273.4 million, as reported in cell H4 of Schedule 4.1 in the COSS in Appendix E) *divided by* 12 months *divided by* 1.6 million Residential customers.

69.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-44 to 5-45

1.69.1 Are the values used in Figure 5-25 and Table 5-11, actual or weather normalized?

RESPONSE:

The input data used in computing the medians are actual consumption, and are not weather normalized.

The medians for each year are computed with the extreme customers removed as per Exhibit B-1, page 5-45, lines 2 to 4, to maintain consistency with the analysis that led to BCUC's 2008 RIB Decision (page 107) and BC Hydro's response to BCUC IR 1.4.7 dated March 18, 2008, as part of the 2008 RIB Application.

Given the large span of data that is already shown in time series (seven years), the graphic already offers rich insights. It shows that even with weather effects in the past seven years, the threshold that was set continues to be reasonable. That is, had the threshold been set based on the average of the medians in the past seven years, the outcome would have been very similar. BC Hydro is of the view that this is the most reasonable presentation of the data to show this result.

In any event, it is not possible to provide comparable figures using weather normalized values. This is because BC Hydro's weather normalized data is typically done for total class consumption for high-level load forecasting purposes, and does not reach the level of resolution for individual customers to produce statistics such as the median.

69.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-44 to 5-45

1.69.2 If actual, please provide a comparable Figure using weather normalized values.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.69.1.

69.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-44 to 5-45

1.69.3 If median use on a weather normalized basis is not available, please provide average weather normalized use for each of the seven years.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.69.1.

69.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-44 to 5-45

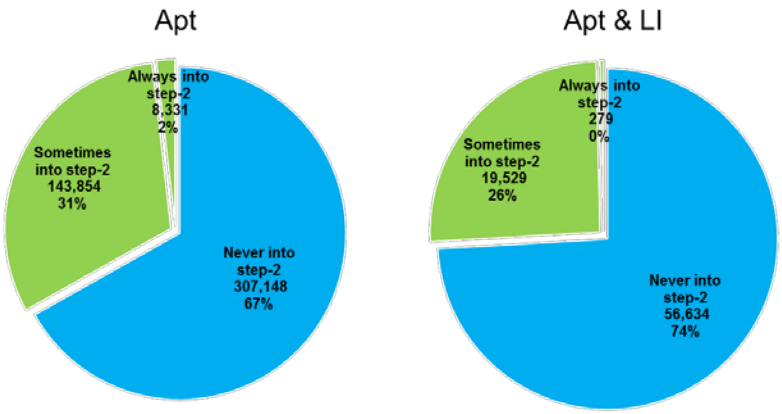
1.69.4 Please repeat Figures 5-26 and 5-27 for customers:

(a) In Apartments;
(b) In Single Family Dwellings;
(c) With Electric Heating;
(d) In Single Family Dwellings with Electric Heating; and
(e) In Apartments with Electric Heating.

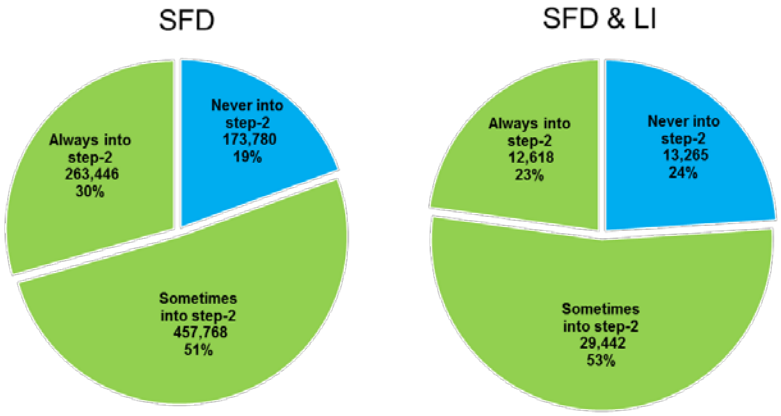
RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates the following:

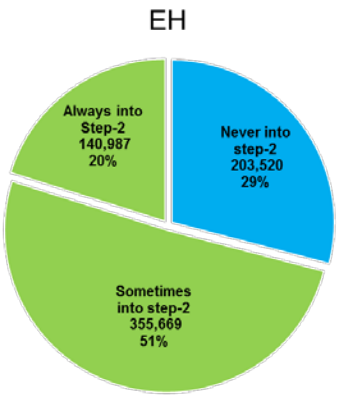
a)

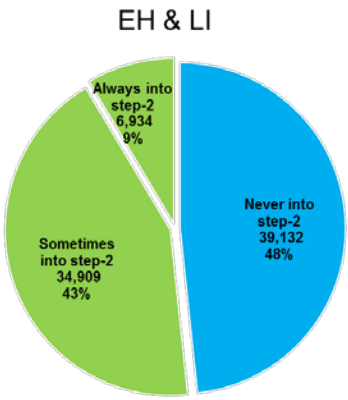


b)

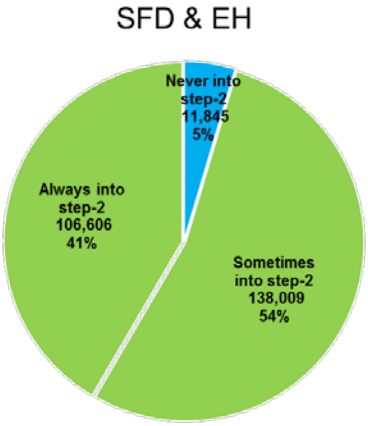


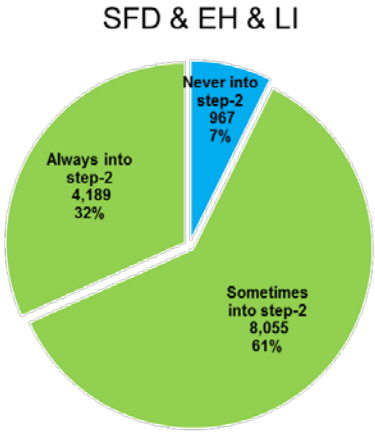
c)


EH
Always into Step-2 140,987 20%
Never into step-2 203,520 29%
Sometimes into step-2 355,669 51%

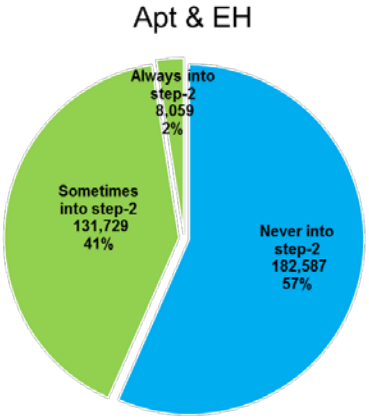

EH & LI
Always into step-2 6,934 9%
Never into step-2 39,132 48%
Sometimes into step-2 34,909 43%

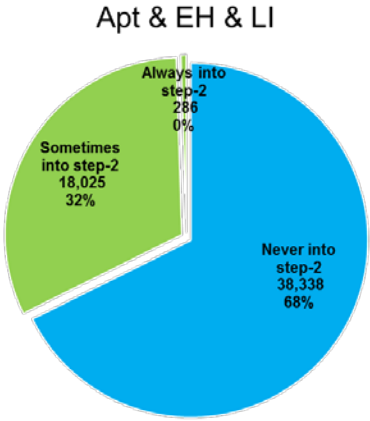
d)


SFD & EH
Never into step-2 11,845 5%
Always into step-2 106,606 41%
Sometimes into step-2 138,009 54%


SFD & EH & LI
Never into step-2 967 7%
Always into step-2 4,189 32%
Sometimes into step-2 8,055 61%

e)


Apt & EH
Always into step-2 8,059 2%
Sometimes into step-2 131,729 41%
Never into step-2 182,587 57%


Apt & EH & LI
Always into step-2 286 0%
Sometimes into step-2 18,025 32%
Never into step-2 38,338 68%

70.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
Residential Inclining Block (RIB) Rate

1.70.1 Please provide the most recent study showing the month-by-month load curve:

(a) For residential customers as a whole for a complete 12-month period;
(b) For each residential tariff class for a complete 12-month period;
(c) For low-income residential customers for a complete 12-month period;
(d) For low-use residential customers, who are also low-income; and
(e) For low-use residential customers, whether or not such customers are low-income, using whatever definition of "low-use" BC Hydro has utilized.

RESPONSE:

All of the Residential rates carried forward in Exhibit B-1 (default and alternatives) are priced on an annual basis. None of the designs are seasonal, or have distinctly different pricing for different months of the year.

BC Hydro is of the view that analysis based on annual metrics, such as annual consumption and annual bills, are the most informative, as opposed to a finer resolution.

For illustrative purposes, the total billed consumption from F2015, by month, by Residential tariff is as follows (items a to b):

In GWh	All Residential	RS 1101	RS 1105	RS 1107	RS 1121	RS 1151	RS 1161
2014 04	1,587	1,519	11	5	8	43	0.1
2014 05	1,321	1,266	7	4	6	37	0.1
2014 06	1,093	1,048	3	4	6	32	0.1
2014 07	1,120	1,075	2	3	5	34	0.1
2014 08	1,024	980	1	3	5	35	0.1
2014 09	1,088	1,044	1	3	5	35	0.1
2014 10	1,129	1,083	3	4	6	34	0.1
2014 11	1,272	1,220	6	4	6	37	0.1
2014 12	1,687	1,616	11	6	10	45	0.1
2015 01	1,868	1,792	13	5	9	48	0.2

In GWh	All Residential	RS 1101	RS 1105	RS 1107	RS 1121	RS 1151	RS 1161
2015 02	1,625	1,553	12	6	8	47	0.2
2015 03	1,517	1,454	10	5	8	41	0.1

1101 - Residential Service

1105 - Residential Service; Dual Fuel (closed)

1107 - Residential Service - Zone II

1121 - Multiple Residential Service

1151 - Exempt Residential Service

BC Hydro does not have the income level of customers in the billing database, and is unable to provide items (c) and (d).

BC Hydro does not label residential customers by their usage level in the billing system, and is unable to provide item (e).

71.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.71.1 Please provide a detailed description of how BC Hydro identified its "low-income customers" in its consideration of the impacts of varying residential rate structures (see, e.g., page 5-23: "only 9 per cent of low income customers would be better off under a flat rate as compared to the RIB rate").

RESPONSE:

It is estimated from the 2014 REUS sample, where customers self-identify their income levels as shown in Exhibit B-1, Appendix C-3F, pages 342 to 348 of 348.

72.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.72.1 Please provide a copy of any study, memo, evaluation or analysis of any nature that discusses, assesses or otherwise considers the differences in the load curve for residential customers depending on the:

(a) Monthly kWh consumption of the customer;
(b) Annual kWh consumption of the customer; and
(c) Income of the customer.

RESPONSE:

(a) and (b): BC Hydro has not done any comprehensive study of Residential load curves based on monthly or annual consumption. BC Hydro notes there is a continuum of Residential consumption from low to high, on either a monthly or annual basis, with no clear distinct categories with different consumption levels. Generally, higher Residential consumption correlates with larger seasonal variations in consumption.

(c): BC Hydro has not done any study with respect to customer income and Residential load curves.

73.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.73.1 In an active Excel spreadsheet:

(a) By month for the most recent twelve months available, disaggregated by heating and non-heating customers, provide a usage distribution in blocks of 50 kWh of consumption with a reasonable top-end usage block determined by BC Hydro. For each usage block identified, provide: (1) the number of accounts in the block; (2) the total consumption in kWh in the block; (3) the average usage in the block; (4) the bill for the average consumption at existing standard residential rates; and (5) the bill for the average consumption at the standard residential rates as proposed by BC Hydro in this proceeding;
(b) Provide the same information for low-income customers;
(c) Provide the same information for customers with annual consumption 80% of median or below; and
(d) Provide the same information for customers with annual consumption 130% of median or above.

RESPONSE:

BC Hydro provided detailed distributions and sample bills of typical customers in various segments in: the Workshop 3 presentation slide deck; the Workshop 9a/9b presentation slide deck; and Exhibit B-1, Figures 5-7 and 5-12.

BC Hydro does not have the data to respond to the detailed request in items (a) to (d). The distributions illustrated in Exhibit B-1 are modelled from the REUS survey responses paired with annual billing data, which is designed to provide a snapshot view of BC Hydro's Residential customers at an aggregate, annual level as opposed to a resolution at the customer-month level further sub-divided by customer characteristics.

74.0 CHAPTER 5 RESIDENTIAL RATE DESIGN
Reference: Exhibit B-1, Section 5.2
RIB Rate

1.74.1 In an active Excel spreadsheet:

(a) For each month for the most recent twelve months available, disaggregated by heating and non-heating residential accounts, please provide the average bill for residential accounts provided in sufficient detail (including all input variables) to permit replication; and

(b) Provide the same bill information with the RRA increases applied to all 3 rate elements rather than BC Hydro's existing rates"?

RESPONSE:

With respect to BCOAPO IR 1.74.1 (a), as BC Hydro does not record heating or non-heating information in customer billing data, the illustrative F2016 bills are modelled based on the median consuming customer as informed by the REUS sample. It is modelled on the annual level, rather than the monthly level, consistent with analytical results reported using the REUS sample in Exhibit B-1 and in the 2015 RDA stakeholder engagement sessions.

Note that (b) concerns RIB rate pricing principle Option 1. While BC Hydro cannot provide the requested bill information with the level of detail requested respect to (a), BC Hydro provides the following to be responsive.

Rates in F2016		
Step 1 (cents/kWh)	**7.97**	
Step 2 (cents/kWh)	**11.95**	
Basic ($/day)	**0.1764**	
Rate Rider (%)	**5**	
Annual kWh by Step	**Illustrative Median Electric Heat Customer**	**Illustrative Median non-Electric Heat Customer**
Step 1	**7027**	**6915**
Step 2	**1158**	**164**
Days in a year	**365**	**365**
Annual Bill by Component **Components Calculated by Multiplying the Amounts by the Rates**		
Step 1 ($)	**560.02**	**551.15**
Step 2 ($)	**138.34**	**19.55**
Basic ($)	**64.39**	**64.39**
Rate Rider (5%)	**38.14**	**31.75**
Total Illustrative Bill, F16	**800.88**	**666.84**
Total Illustrative Bill, F16 + RRA of 4%	**832.92**	**693.52**

75.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.75.1 Please identify the objectives BC Hydro seeks to accomplish or achieve with a Residential Inclining Block rate structure. Place these objectives in rank order if they are not of equal importance.

RESPONSE:

As discussed at Workshop 9a, the main objective of the RIB rate is to achieve energy conservation (Workshop 9a/9b consideration memo, Exhibit B-1, Appendix C-3B, page 368 of 609). As set out in Table 5-7 of Exhibit B-1, BC Hydro considers that the RIB rate has been performing well in respect of this objective. F2017 forecast cumulative conservation = 463 GWh/year (since 2008).

The performance of the RIB rate as compared to the eight Bonbright criteria is set out in Table 5-7 of Exhibit B-1. Consistent with BC Hydro's general Bonbright criteria prioritization, BC Hydro prioritized customer understanding (in particular bill impacts), fairness and rate stability given that the RIB rate is performing as expected.

76.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.76.1 Please identify what level of monthly usage (in kWh) is required to meet residential essential needs in a non-electric space heating household. Identify each end-use included in this essential needs and the monthly usage assumed for each such end-use.

RESPONSE:

BC Hydro is not aware of a commonly accepted definition of what constitutes "residential essential needs in a non-electric space heating household".

BC Hydro notes Manitoba Hydro's load limiter-related threshold implemented during its heating season of October 1 to May 14. If during that time a residential account becomes delinquent, Manitoba Hydro may install a load limiter on electric service which limits the capacity of the service to 15 amps, which Manitoba Hydro states allows enough electrical energy for a furnace to run.[1] Refer to section 5.4.4 of BC Hydro's low income terms and conditions review found as Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

[1] Manitoba Hydro, "Manitoba Hydro Affordable Energy Program", 10 November 2009, page 10 of 46; http://www.pub.gov.mb.ca/exhibits/mh2011/Volumes/app44-1.pdf.

77.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.77.1 To the extent that average monthly residential usage exceeds the essential needs usage identified in the response to the Information Request immediately above, please identify what end uses are included in the average but not in the essential needs. Identify both the end-use and the usage (in kWh) associated with that end-use.

RESPONSE:

BC Hydro is not aware of a commonly accepted definition of what constitutes "residential essential needs in a non-electric space heating household". Please refer to BC Hydro's response to BCOAPO IR 1.76.1.

78.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.78.1 Please indicate whether the level of usage to meet essential needs as identified in response to Information Requests above varies based on the income of the customer.

RESPONSE:

BC Hydro is not aware of a commonly accepted definition of what constitutes "residential essential needs in a non-electric space heating household". Please refer to BC Hydro's response to BCOAPO IR 1.76.1.

78.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.78.1 Please indicate whether the level of usage to meet essential needs as identified in response to Information Requests above varies based on the income of the customer.

1.78.1.1 If yes, provide a detailed explanation of how, why, and to what extent such variation exists.

RESPONSE:

BC Hydro is not aware of a commonly accepted definition of what constitutes "residential essential needs in a non-electric space heating household". Please refer to BC Hydro's response to BCOAPO IR 1.76.1.

79.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.79.1 Please identify and provide a copy of all instances where BC Hydro has used any of the following metrics in measuring the targeting of rate relief delivered through a universal (in contrast to a means-tested or income-targeted) RIB rate:

(a) The beneficiary incidence as defined by the World Bank in assessing inclining block rate utility structures;
(b) The benefit incidence as defined by the World Bank in assessing inclining block rate utility structures;
(c) Omega (Ω) defined by the World Bank as the share of the subsidy benefits received by the poor divided by the proportion of the population in poverty; and
(d) To the extent previously used by BC Hydro, indicate whether its use distinguished between heating and non-heating customers.

RESPONSE:

BC Hydro has not used any of the metrics described above in assessing its RIB rate.

80.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.80.1 To the extent that the BC Hydro analysis referenced and provided in response to the Information Request immediately above found an Omega less than 1.0, please provide all analyses by BC Hydro or others postulating, evaluating or otherwise discussing why an Omega of this value was present.

RESPONSE:

Not applicable. Please refer to BC Hydro's response to BCOAPO IR 1.79.1.

81.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.81.1 Please confirm or deny whether higher residential usage is associated with higher contributions to peak demand on BC Hydro's system, if heating and non-heating accounts are considered separately. If denied, provide a detailed explanation of the basis for that denial.

RESPONSE:

Confirmed. However, BC Hydro notes there is a continuum of heating sources and it is difficult to classify customers as "heating" or "non-heating" (refer to pages 4-4 and 4-5 of Exhibit B-1). Generally, customers that predominantly heat with electricity have monthly peak winter loads in the range of 6 kW to 12 kW while customers with no or very little electric heating load have monthly peak loads in the range of 4 kW to 8 kW. BC Hydro has not done a comprehensive analysis to determine each group's share of the system's coincident peak.

82.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.82.1 Please provide a copy of all written documents of any nature within BC Hydro's custody or control, if any, which empirically establish that peak kW demand may be less responsive to changes in price than kW of demand at other times.

RESPONSE:

BC Hydro does not have custody or control of any recent documents dating between 2011 and 2015 which empirically establish that residential peak kW demand may be less responsive to change in price than kW of demand at other times. As noted in BC Hydro's response to COPE 378 IR 1.4.2, BC Hydro uses a 2011 cut-off date given that it has been B.C. Government policy since 2011 that mandatory TOU rates for Residential and/or General Service customers is not an option for BC Hydro.

With respect to literature reviews, please refer to BC Hydro's response to BCOAPO IR 1.83.1.

While not directly related to the question posed in this IR, please refer to BC Hydro's responses to the COPE 378 1.4 series with respect to Residential TOU rate-related work since 2011.

83.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.83.1 Please indicate BC Hydro's agreement or disagreement with each of the following statements. If there is disagreement, provide a detailed explanation of the basis for each disagreement.

(a) Households with air conditioning tend to be more price responsive than those without;
(b) Consumption in peak periods is more elastic than consumption in off-peak periods, in the context of time varying tariffs; and
(c) Peak and off-peak consumption tend to be substitutes—a rise in the peak period price tends to lead to shifting of consumption away from the peak and into the off-peak period.

RESPONSE:

(a) Although BC Hydro did not test the impact of air conditioning (AC) in its analysis of the RIB rate, BC Hydro agrees that the existing literature from other jurisdictions supports the notion that households with AC tend to be more responsive to changes in electricity price than do households without AC, all else being equal. The following findings lend support for this statement:

1. **In a study of California, Reiss and White (2005)[1] estimate a short-run own-price elasticity of electricity demand for households with central or room AC of -0.64, versus -0.20 for households with no AC;**

2. **Using data from California's Statewide Pricing Pilot, Faruqui and George (2005)[2] find that AC ownership has a significant influence on the magnitude of customers' electricity demand response to price increases on Critical Days. Critical Day peak-period energy use reductions were more than twice as large for households with AC than for those without AC (17.43 per cent reduction versus 8.05 per cent reduction);**

3. **Barnes et al. (1981)[3] find price elasticities of electricity demand of:**

   - **-1.2 for central AC, and**

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[1] **Faruqui, A. and S. George (2005) "Quantifying Customer Response to Dynamic Pricing," *Electricity Journal*, 18(4): 1040 – 6190.**
[2] **Reiss P.C. and M.W. White (2005) "Household Electricity Demand, Revisited," *Review of Economic Studies*, 72: 853-883.**
[3] **Barnes, R., R. Gillingham, and R. Hageman (1981) "The Short-Run Residential Demand for Electricity," *Review of Economics and Statistics,* 63(4): 541-552.**

- **-1.87 and -2.02 (under two different estimation approaches) for portable AC.**

4. **Using data from Florida Power and Light, Dubin, Miedema and Chandran (1986)[4] find monthly price elasticity of electricity demand values for cooling technologies that range from -0.84 to -0.07 during the months January to October; and**

5. **In a review of several RAND studies of residential electricity demand under time-of-day rates, Acton and Park (1984)[5] conclude that "Air conditioning, electric space heating, water heating, clothes dryers, stoves, and swimming polls all increase the price elasticities [for residential electricity demand] notably".**

(b) BC Hydro agrees that consumption in peak periods is more elastic than consumption in off-peak periods in the context of time varying tariffs.

(c) BC Hydro agrees with the statement that peak and off-peak consumption tend to be substitutes. While the historical literature is mixed on the subject, with results varying by jurisdiction, the most recent literature shows that peak and off-peak consumption are substitutes:

1. **Thorsnes, Williams and Lawson (2012)[6] report substitution elasticity of -0.453 for residential electricity consumption in Auckland, New Zealand, indicating that a 1 per cent increase in the ratio of peak to off-peak prices will lead to a 0.453 per cent decrease in the ratio of peak to off-peak consumption; and**

2. **Using city-level data from 22 Swiss cities, Filippini (2011)[7] finds short-run cross price elasticities of peak/off-peak electricity consumption of 0.793 and 0.917 using two different model specifications, and long-run cross-price elasticities of 1.767 and 2.311. These positive values suggest that peak and off-peak electricity are substitutes.**

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[4] **Dubin, J.A., A.K. Miedema and R.V. Chandran (1986) "Price Effects of Energy-Efficient Technologies: A Study of Residential Demand for Heating and Cooling," *Rand Journal of Economics* 17(3): 310-325.**

[5] **Acton, J.P. and R.E. Park, "Projecting Response to Time-of-Day Electricity Rates," RAND Report N-2041- MD, December 1984.**

[6] **Thorsnes, P., J. Williams, and R. Lawson, "Consumer Responses to Time Varying Prices for Electricity," *Energy Policy, 49:552-561.***

[7] **Filippini, M. (2011) "Short- and Long-Run Time-of-Use Price Elasticities in Swiss Residential Electricity Demand," *Energy Policy,* 39: 5811 – 5817.**

84.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.84.1 For BC Hydro's preferred default residential rate (i.e. the existing RIB rate), please indicate the monthly break-even point of usage, where a customer is neither better off nor worse off compared to a flat rate structure.

RESPONSE:

As an illustration, in the case where a customer consumes the same kWh for every month of the year, the break-even point of usage is at 13,915 kWh/year (1,159 kWh/month). However, the break-even consumption depends on the consumption patterns of the customers throughout the year. This is shown by Exhibit B-1, Figure 5-13, which shows the bill impacts computed using BC Hydro's representative sample of 10,000 customers.

In Figure 5-13, the consumption levels where the bill impact:

- **Equals the RRA line of 4 per cent represents an annual consumption amount that leads to an annual bill that is indifferent between the flat rate and the existing RIB rate;**
- **Is higher than the RRA line of 4 per cent represents an annual consumption amount that leads to an annual bill that is higher under the flat rate in comparison to the existing RIB rate; and**
- **Is lower than the RRA line of 4 per cent represents an annual consumption amount that leads to an annual bill that is lower under the flat rate in comparison to the existing RIB rate.**

85.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.85.1 For the recommended Residential Inclining Block rate in BC Hydro's application, provide in an active Excel spreadsheet, in usage increments of 100 kWh, using the maximum usage level in each increment and a reasonable top-coded usage block, whether customers in that usage block are "winners" or "losers," and the amount of gain or loss.

RESPONSE:

In the context of characterizing consumption levels that would lead to a higher or lower bill under the flat rate vs. the existing RIB rate, please refer to BC Hydro's response to BCOAPO IR 1.84.1.

86.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.86.1 Provide separate monthly usage distribution curves for low-income customers (as previously defined) and non-low-income customers (or residential customers irrespective of income if non-low-income is unavailable). Identify the usage amount at which the right tail of the low-income population intersects the left tail of the non-low-income population, if at all.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.70.1

87.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.87.1 For each usage distribution curve provided in response to the Information Request immediately above, identify the upper and lower bounds of usage at which BC Hydro determines the steeply sloping portion of the demand curve becomes the flat portion. If a single point (called a “kink”) can be identified, identify the point of usage representing that kink for each curve.

RESPONSE:

Please refer to BC Hydro’s response to BCOAPO IR 1.70.1.

88.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.88.1 In an active Excel spreadsheet, disaggregating by heating and non-heating customers, by monthly from January 2010 to present inclusive, provide the:

(a) Residential usage at the average (mean);
(b) Residential usage at the median;
(c) Residential usage at 50% of the median;
(d) Residential usage at 70% of the median;
(e) Residential usage at 125% of the median; and
(f) Residential usage at 150% of the median.

RESPONSE:

BC Hydro cannot provide the requested monthly usage breakdown in the time allotted to respond for the reasons set out in BC Hydro's response to BCOAPO IRs 1.58.2 and 1.73.1.

To be responsive, BC Hydro estimates the following using the 2014 REUS sample:

a)

	Mean Consumption (kWh)
F2015	9,938
F2014	11,123
F2013	11,040
F2012	11,724
F2011	11,575
F2010	11,044

b); c); d); e) and f)

	Median Consumption (kWh)	50% of Median Consumption (kWh)	70% of Median Consumption (kWh)	125% of Median Consumption (kWh)	150% of Median Consumption (kWh)
F2015	8,184	4,092	5,729	10,230	12,276
F2014	9,235	4,618	6,465	11,544	13,853
F2013	9,559	4,779	6,691	11,948	14,338
F2012	10,026	5,013	7,018	12,532	15,039
F2011	9,375	4,687	6,562	11,718	14,062
F2010	9,019	4,510	6,313	11,274	13,529

89.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.89.1 Please provide all written documents of any nature in which BC Hydro assesses, evaluates or otherwise discusses the relative impacts of delivering low-income bill relief by a RIB rate with a smaller initial block and a deeper discount relative to a RIB rate with a broader initial block and a shallower discount.

RESPONSE:

This question is unbounded in terms of any period of time. BC Hydro confines its response to materials prepared and circulated as part of its 2015 RDA stakeholder engagement. That engagement identified possible three step rate designs as a means of delivering low income bill relief through a "universal" rate as opposed to a low income rate. In response to BCOAPO feedback, BC Hydro modelled the relative impacts of two alternative three-step rate designs for delivering bill relief at low levels of consumption (Model B and Model C). The results were presented at Workshop 9a (slides 49-59), attached at Appendix C-3B of Exhibit B-1. Each of Model B and C had a small initial block of consumption of 250 kWh/month, but with differing discounts subject to the parameters of each model and the need to maintain revenue neutrality.

In addition, BC Hydro reviewed the impacts on low-income customers in its analysis of alternative means of delivering the RIB rate, as set out in the material concerning Workshops 3 and 9a/9b, including in respect of considering alternative pricing principles, Step 1/Step 2 consumption thresholds and basic and minimum charges.

90.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.90.1 In an active Excel spreadsheet, please provide, disaggregated by heating and non-heating customers, a usage distribution by month for the most recent 12 months available, in the smallest bins used by BC Hydro to determine usage distributions, broken down by quintiles of residential consumption. In this data, the "first quintile" would be the quintile with the lowest average annual consumption for the 12 months studied; the "fifth quintile" would be the quintile with the highest average annual consumption for the 12 months studied. BC Hydro can determine a reasonable top-coded usage amount. For each usage bin, provide:

(a) The number of accounts in each bin;
(b) The aggregate consumption in each bin; and
(c) The average consumption in each bin.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.73.1.

91.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

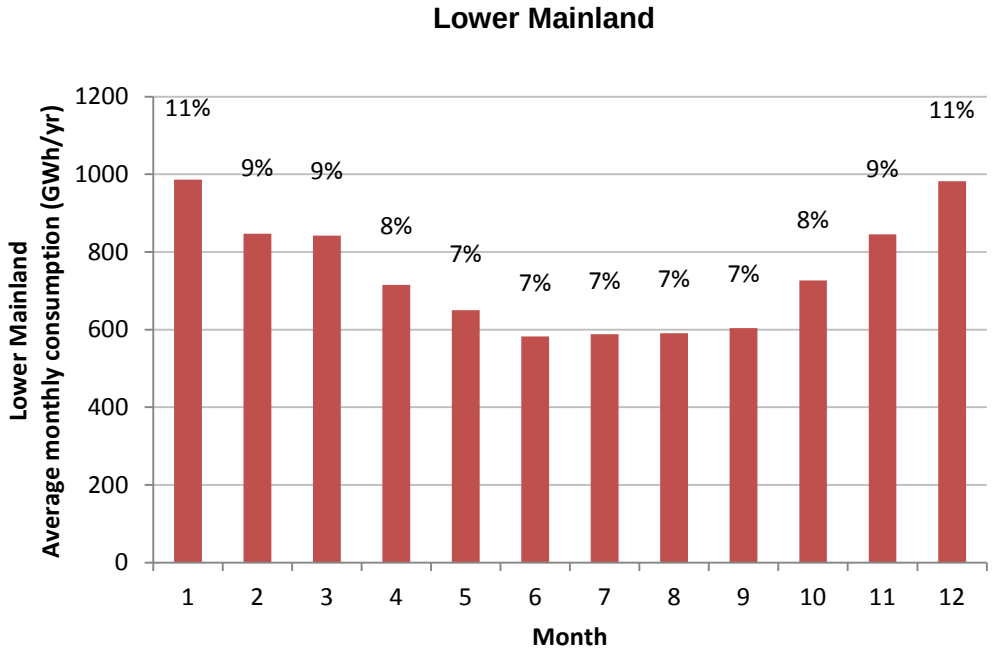
Reference: Exhibit B-1, Section 5.2, Figure 5.2
RIB Rate

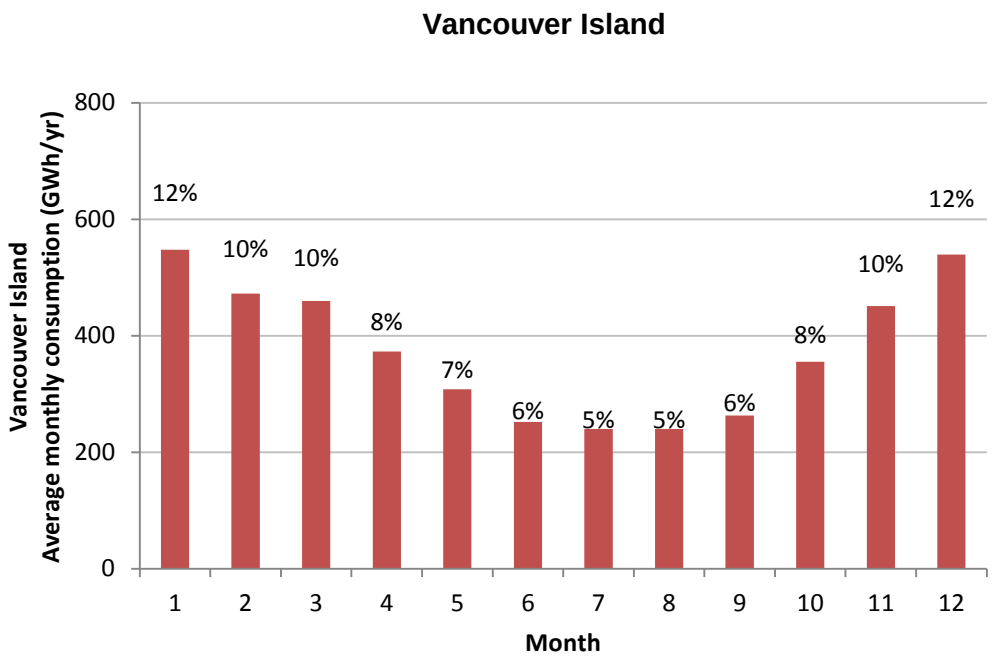
Figure 5.2 in the Application shows Average Residential Class Consumption by Month for F2011 to F2015.

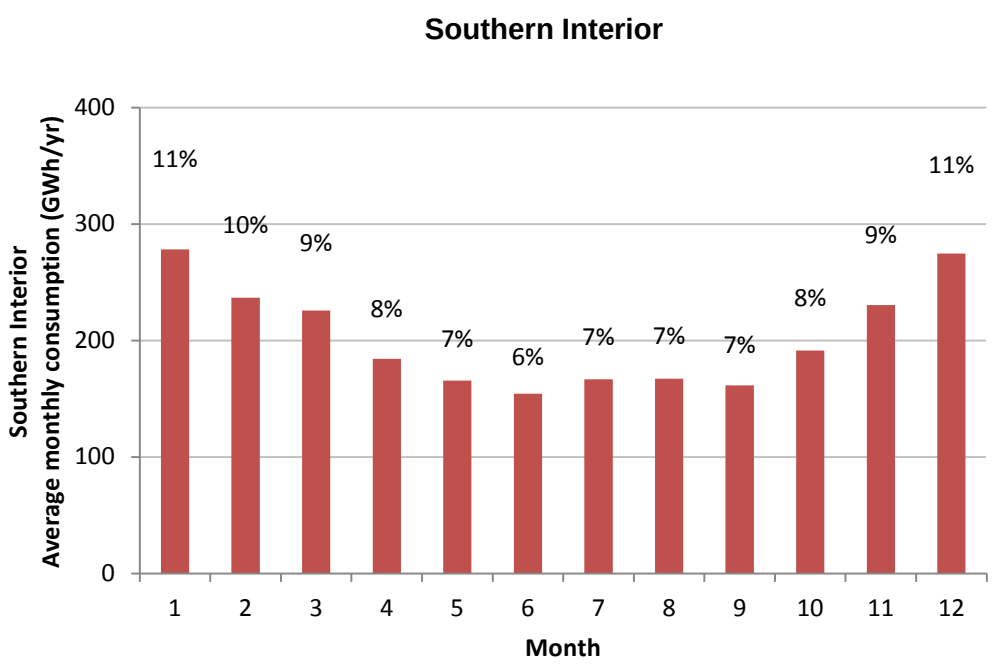
1.91.1 Please provide separate graphs similar to Figure 5.2 for each of the following regions: Vancouver Island, Lower Mainland, Southern Interior, and the North.

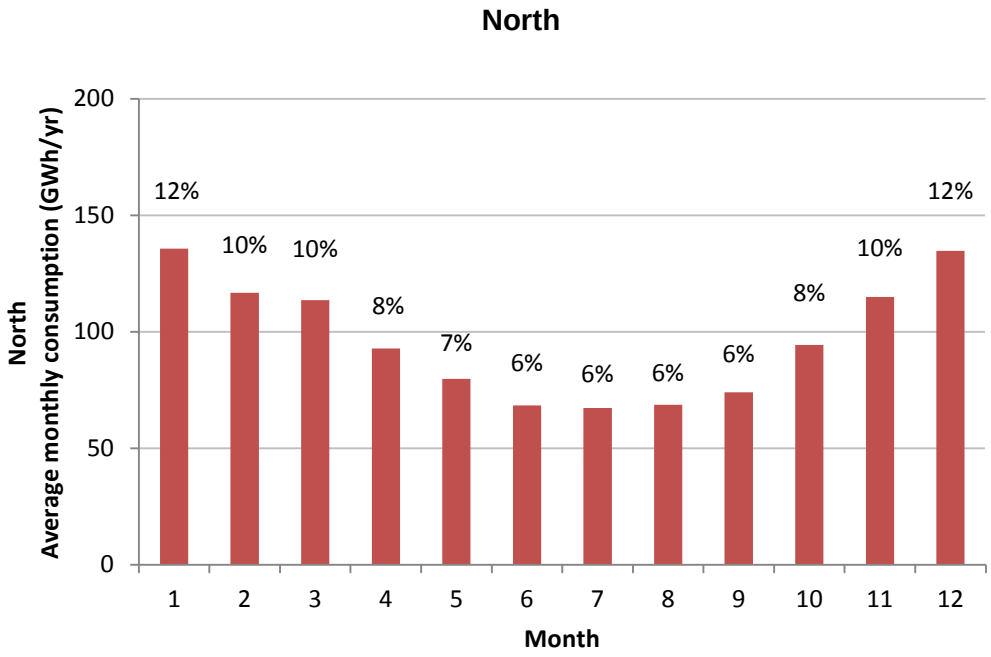
RESPONSE:

The average residential rate class consumptions by month over the period between F2011-F2015 are illustrated below.




Vancouver Island
Vancouver Island
Average monthly consumption (GWh/yr)
800
600
400
200
0
12%
10%
10%
8%
7%
6%
5%
5%
6%
8%
10%
12%
1
2
3
4
5
6
7
8
9
10
11
12
Month


Southern Interior
Southern Interior
Average monthly consumption (GWh/yr)
400
300
200
100
0
11%
10%
9%
8%
7%
6%
7%
7%
7%
8%
9%
11%
1
2
3
4
5
6
7
8
9
10
11
12
Month


North
North
Average monthly consumption (GWh/yr)
200
150
100
50
0
12%
10%
10%
8%
7%
6%
6%
6%
6%
8%
10%
12%
1
2
3
4
5
6
7
8
9
10
11
12
Month

91.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2, Figure 5.2
RIB Rate

Figure 5.2 in the Application shows Average Residential Class Consumption by Month for F2011 to F2015.

1.91.2 Please provide any available data on average or median energy use on reserves per household, using the same format as Figure 5.2 to display the data.

RESPONSE:

BC Hydro cannot provide the requested monthly usage breakdown in the time allotted to respond for the reasons set out in BC Hydro's response to BCOAPO IR 1.58.2. To be responsive, BC Hydro provides the annual median energy consumption for residential accounts on reserves are as follows:

F2012 12,171 kWh

F2013 11,623 kWh

F2014 11,390 kWh

F2015 10,628 kWh.

92.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.92.1 How many BC Hydro customers currently use more than 2000, 2100, 2200, 2300 and 2400 kWh per month on average? Please provide the answer in the form of a chart/graph, broken up by month.

RESPONSE:

BC Hydro provides the following account estimates based on F2015 residential billing data.

Region	Year-Month	Estimated Number of Residential Accounts in each Month Exceeding the Stated Consumptions:				
		2000 kWh	2100 kWh	2200 kWh	2300 kWh	2400 kWh
All Four Regions (Lower Mainland, Northern, Southern Interior, Vancouver Island)	201404	78,802	67,663	58,545	50,872	44,396
	201405	42,519	36,539	31,823	28,129	24,967
	201406	30,127	26,401	23,552	21,146	19,128
	201407	35,185	30,679	27,024	24,047	21,658
	201408	34,333	30,014	26,431	23,564	21,178
	201409	31,234	27,252	24,035	21,534	19,424
	201410	62,929	53,696	46,299	40,226	35,145
	201411	141,079	123,409	108,396	95,158	83,716
	201412	218,086	194,416	173,683	155,458	139,035
	201501	203,648	181,335	161,536	144,113	128,527
	201502	120,472	105,077	91,836	80,391	70,539
	201503	114,425	99,279	86,534	75,441	65,863
Lower Mainland	201404	32,672	28,480	25,085	22,242	19,840
	201405	22,067	19,301	17,145	15,385	13,842
	201406	17,189	15,227	13,700	12,415	11,339
	201407	19,628	17,266	15,384	13,824	12,522
	201408	19,549	17,198	15,245	13,706	12,419
	201409	17,527	15,448	13,841	12,509	11,395
	201410	28,518	24,782	21,757	19,279	17,169
	201411	53,150	46,315	40,654	35,796	31,648
	201412	82,786	72,746	64,242	56,978	50,773
	201501	76,145	66,985	58,998	52,270	46,465
	201502	43,765	38,163	33,615	29,628	26,315
	201503	43,622	38,054	33,468	29,527	26,157

Region	Year-Month	Estimated Number of Residential Accounts in each Month Exceeding the Stated Consumptions:				
		2000 kWh	2100 kWh	2200 kWh	2300 kWh	2400 kWh
Northern	201404	6,545	5,672	4,896	4,231	3,651
	201405	2,830	2,361	1,978	1,689	1,477
	201406	1,383	1,150	992	874	758
	201407	1,338	1,146	976	850	757
	201408	1,407	1,182	1,021	880	789
	201409	1,830	1,544	1,289	1,092	942
	201410	5,413	4,540	3,883	3,315	2,848
	201411	11,771	10,413	9,232	8,195	7,271
	201412	17,418	15,715	14,143	12,787	11,501
	201501	16,743	15,079	13,604	12,286	11,050
	201502	10,788	9,509	8,393	7,455	6,556
	201503	9,413	8,277	7,269	6,374	5,548
Southern Interior	201404	11,587	9,987	8,755	7,629	6,662
	201405	6,372	5,465	4,762	4,212	3,735
	201406	5,141	4,456	3,943	3,511	3,133
	201407	7,518	6,445	5,561	4,858	4,308
	201408	6,772	5,846	5,120	4,524	3,999
	201409	4,990	4,344	3,799	3,396	3,049
	201410	9,429	8,097	7,032	6,145	5,400
	201411	22,034	19,599	17,439	15,538	13,912
	201412	33,945	30,767	27,965	25,527	23,083
	201501	32,507	29,490	26,713	24,232	21,989
	201502	20,053	17,780	15,817	14,021	12,508
	201503	16,488	14,423	12,620	11,109	9,801
Vancouver Island	201404	27,998	23,524	19,809	16,770	14,243
	201405	11,250	9,412	7,938	6,843	5,913
	201406	6,414	5,568	4,917	4,346	3,898
	201407	6,701	5,822	5,103	4,515	4,071
	201408	6,605	5,788	5,045	4,454	3,971
	201409	6,887	5,916	5,106	4,537	4,038
	201410	19,569	16,277	13,627	11,487	9,728
	201411	54,124	47,082	41,071	35,629	30,885
	201412	83,937	75,188	67,333	60,166	53,678
	201501	78,253	69,781	62,221	55,325	49,023
	201502	45,866	39,625	34,011	29,287	25,160
	201503	44,902	38,525	33,177	28,431	24,357

92.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2
RIB Rate

1.92.1 How many BC Hydro customers currently use more than 2000, 2100, 2200, 2300 and 2400 kWh per month on average? Please provide the answer in the form of a chart/graph, broken up by month.

1.92.1.1 Please provide a separate chart/graph for each of the following geographical regions: Vancouver Island, Lower Mainland, Southern Interior, and the North.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.92.1.

93.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.2, p. 5-29
RIB Rate

BC Hydro states in the Application that it "advised Workshop 9a/9b participants of the outcome of the California Public Utilities Commission's (CPUC) June 21, 2015 residential rate reform plan, which will see the current four step residential rates of the three large investor owned utilities - Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric - reduced to two steps."

1.93.1 Please confirm the California utilities referenced above are moving to a two tier structure with a surcharge for high consumption.

RESPONSE:

Confirmed; the second tier rate is estimated to be approximately 25 per cent higher than the first tier rate.

94.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-48 and 2-46

1.94.1 Do all current Residential E-Plus customers have smart meters with RDR capability?

RESPONSE:

Over 90 per cent of Residential E-Plus customers have smart meters with RDR capability.

94.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-48 and 2-46

1.94.2 If not, what is BC Hydro's proposed treatment from those who do not?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.43.1.

95.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-51

1.95.1 For purposes of the COSS set out in Appendix D were the Residential E-Plus heating loads included in the determination of the energy and demand allocators for the Residential class?

RESPONSE:

Yes.

95.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-51

1.95.1 For purposes of the COSS set out in Appendix D were the Residential E-Plus heating loads included in the determination of the energy and demand allocators for the Residential class?

1.95.1.1 If yes, what would be the impact of excluding them?

RESPONSE:

BC Hydro estimates the impact would be a 0.2 percentage point rise in the Residential R/C ratio from 93.9 per cent to 94.1 per cent.

96.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-54 to 5-56

1.96.1 Under Option 3, is there any reason to maintain the Residential E-Plus rate as closed to new participants?

RESPONSE:

Yes, for the following reasons:

- **While BC Hydro's proposal is intended to make the Residential E-Plus rate truly interruptible and serve a useful function, the cost to serve E-Plus heating load will continue to be under-recovered, as shown in Table 5-13 of Exhibit B-1;**
- **BC Hydro has no practical experience in interrupting a dispersed Residential load; and**
- **No other Canadian jurisdiction has a residential interruptible rate, and therefore there is no Canadian jurisdictional experience to draw on.**

96.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-54 to 5-56

1.96.1 Under Option 3, is there any reason to maintain the Residential E-Plus rate as closed to new participants?

1.96.1.1 If yes, why?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.96.1.

96.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-54 to 5-56

1.96.2 With respect to notice of interruption (page 5-56), there is no reference to what is the shortest notice period that BC Hydro will provide. Does BC Hydro propose that there would be one and, if so, what would it be? Alternatively, could customers still be subject to interruption even if prior notice (as outlined at lines 26-27) has not been given?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.43.1.

97.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.4
Low income rate

1.97.1 If an income verification system is set up for low income Terms and Conditions of service, please confirm whether the same system could also be used for customers who are eligible for a lifeline rate?

RESPONSE:

Confirmed. However, the upfront implementation cost of billing system changes would increase if the verification system related to both low income terms and conditions and a low income rate.

Please refer to section 5.1 of Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1 for a discussion of low income verification systems and related administrative costs.

98.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.4, p. 5-60
Low income rate

1.98.1 Does BC Hydro agree that the Manitoba Public Utilities Board found that affordability is a factor to consider in setting just and reasonable rates, as per the Public Utility Board's decision at p. 29?

RESPONSE:

Sections 59 and 60 of the *UCA* are similar to section 67 of the Nova Scotia *Public Utilities Act* and subsection 121(2)(b) of the Alberta *Electric Utilities Act*; refer to BC Hydro's low income rate/low income terms and conditions/low income DSM program jurisdictional review, Exhibit B-1, Appendix C-3D, pages 39, 44 and 45 of 67.

<u>Manitoba</u>

BC Hydro submits that the MPUB's decision can be distinguished on the basis of differing legislation.

In BC Hydro's view, the statutory framework governing the MPUB is different from sections 59 and 60 of the *UCA*. There is no equivalent to subsection 26(4)(a) of the Manitoba *Crown Corporations Public Review and Accountability Act* authorizing the MPUB to consider "any compelling policy considerations that [the MPUB] considers relevant to the matter".

The MPUB cited this provision as providing it with jurisdiction[1] to order a collaborative process to develop a bill affordability program that could consist of a residential inclining block rate similar to BC Hydro's RIB rate. The MPUB concluded that section 26(4)(a) of the Manitoba *Crown Corporations Public Review and Accountability Act* meant that the MPUB's jurisdiction is similarly broad to the OEB pursuant to section 36 of the *Ontario Energy Board Act*, which authorizes the OEB to use "any method or technique it considers appropriate" in approving "just and reasonable rates".

<u>Ontario</u>

A reading of sections 59 and 60 of the *UCA* demonstrate that there is no equivalent to subsection 36(3) of the *Ontario Energy Board Act* as there is no section giving the Commission the authority to adopt any method or technique.

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[1] **MPUB Order 73/15, July 24, 2015, page 29 of 108;**

Please note that with respect to the Ontario portion of the low income rate/low income terms and conditions/low income DSM program jurisdictional review, the Ontario government introduced legislation to enable implementation of the Ontario Electricity Support Program. Schedule 31 of the *Building Ontario Up Act (Budget Measures, 2015*[2] amended the *Ontario Energy Board Act* by introducing section 79.2 to the *Ontario Energy Board Act* as follows:

> **99.2(1) The Board may, in approving just and reasonable rates for a distributor, make provision for rate assistance to rate-assisted customers having regard to their economic circumstances.**
>
> **…**
>
> **99.2(4) The Board may, by order or by establishing or amending a code, identify one or more classes of consumers as rate-assisted customers.**

Please also refer to BC Hydro's responses to CEC IR 1.46.1 and COPE 378 IR 1.12.1.

[2] **S.O. 2015, c.20, assented to June 4, 2015; http://www.ontario.ca/laws/statute/S15020.**

99.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-69 to 5-70

1.99.1 Based on the paragraph starting at line 25 of page 5-69, is dwelling size a factor in driving higher than average energy use?

RESPONSE:

Yes.

99.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-69 to 5-70

1.99.2 For dwellings with electric heat, is either dwelling type or size a factor in driving higher than average energy use? Please provide the analysis supporting the response.

RESPONSE:

Yes. Please refer to Exhibit B-1, Appendix C-3F, pages 242 and 243 of 348.

100.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-70 to 5-71

1.100.1 With respect to page 5-71 (lines 14-21), what portion of Residential customers would see a bill decrease of greater than 10% if a flat energy rate were put in place as opposed to the current RIB rate?

RESPONSE:

BC Hydro estimates that with a flat rate, in F2017 0.3 per cent of Residential accounts will experience bill decrease of greater than 10 per cent when compared to the proposed RIB rate.

100.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-70 to 5-71

1.100.2 With respect to page 5-71 (lines 14-21), what portion of low income Residential customers would see a bill decrease of greater than 10% if a flat energy rate were put in place as opposed to the current RIB rate?

RESPONSE:

BC Hydro estimates that with a flat rate, in F2017 0.2 per cent of low income accounts will experience bill decrease of greater than 10 per cent when compared to the proposed RIB rate.

101.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-71

Question 3 from the Minister's RIB Report Letter inquires as to "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?"

1.101.1 At page 5-69 BC Hydro identifies what it considers as the factors that lead to higher than average electricity use. Are these same factors applicable for areas without natural gas service and for low income customers?

RESPONSE:

In general, region and housing type influence the amount of electricity use for all Residential customers in BC Hydro's service area.

101.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-71

Question 3 from the Minister's RIB Report Letter inquires as to "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?"

1.101.2 Are there other factors driving higher than average electricity use that are unique to either areas without natural gas and/or low income customers?

RESPONSE:

In BC Hydro's view, the three factors set out in section 5.5.2 of Exhibit B-1 apply to Residential customers without access to natural gas and low income customers.

102.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-72

1.102.1 There does not appear to be a section addressing the portion of Question 5 regarding "what options there are for additional residential DSM program, including low income programs, within the current regulatory environment" (per lines 9-11). Is it BC Hydro's view that there are no options for additional DSM programs?

RESPONSE:

For the reasons set out below, BC Hydro considers it premature at this time to address Minister RIB Report Letter Question 5 as to whether there are options for additional Residential DSM programs, including low income programs, within the current regulatory environment.

BCOAPO IRs 1.102.1 to 1.113.1, 1.119.1 to 1.120.1, 1.123.1 to 1.125.1, 1.128.1 to 1.134.1 and 1.135.1 to 1.136.2 ask a series of detailed questions concerning BC Hydro's low income and/or Residential DSM programs and/or other DSM initiatives that are not rate structures. In some instances, and as noted in specific IR responses, BC Hydro respectfully declines to respond to the question on the basis that the requested information is not relevant to and cannot aid in the review of 2015 RDA Module 1 or the orders sought with respect to it or for purposes of the Minister RIB Report Letter. As a general approach BC Hydro weighed the relevance of each question (questionable, limited or no relevance) with the burden to obtain and/or produce the requested information, (e.g., unduly onerous):

1. **As set out at Exhibit B-1, page 5-73, lines 1 to 6, DSM programs are not rates. The proper venue for examination of BC Hydro's Residential DSM programs is a section 44.2 *UCA* DSM expenditure schedule determination filing. BC Hydro will be submitting a DSM expenditure schedule filing contemporaneously with or as part of the F2017 RRA in February 2016;**

2. **Given the above, any examination of Residential DSM programs in the 2015 RDA review process must be tied to the Minister RIB Report Letter Questions 4 and 5: "What is the potential for BC Hydro's existing Residential DSM programs to mitigate RIB rate impacts on low income customers and customers without access to natural gas?" and "Within the current regulatory environment, what options are there for additional DSM programs, including low income programs?". As discussed below, these questions are to be answered in the context of RIB rate bill impacts.**

In regard to point 2, BC Hydro reproduces its response to BCUC IR 1.51.1 for convenience.

"In BC Hydro's view, the Minister RIB Report Letter Questions 1 to 5 call for a two-phased review of BC Hydro's RIB rate. This is clear from Question 4, which asks: "What is the potential for existing [DSM] programs to mitigate these *impacts*" [emphasis added].

First, is there evidence that the RIB rate has high bill impacts on the following BC Hydro Residential customer segments, with the phrase "high bill impacts" defined in the Minister RIB Report Letter to mean "over 10 per cent":

1. **BC Hydro's low income customers (Question 2) - No stakeholder submitting comments in the Commission's RIB Report proceeding contests that low incomers should be defined for RIB Report purposes using Statistics Canada's LICO; using pre-tax income levels LICO, the answer to this question is no under either of the two RIB rate F2017-F2019 pricing principle options discussed in section 5.2.5.1 of Exhibit B-1:**

   - **Under BC Hydro's proposed RIB rate pricing principle Option 1, no low income customer will have a bill impact greater than 10 per cent (Exhibit B-1, page 5-71, lines 8 to 13);**

   - **Under RIB rate pricing principle Option 2, no low income customers will have a bill impact greater than 10 per cent (Exhibit B-1, Figures 5-20 and 5-23).**

   In addition, only 9 per cent of low income customers would be better off under a flat rate as compared to a RIB rate (refer to Table 5-4 of Exhibit B-1).

2. **BC Hydro's customers without access to natural gas, including low income customers (Question 3) - BC Hydro accepts that there is some uncertainty as to the definition of customers without access to natural gas. The answer is no under either of the two RIB rate F2017-F2019 pricing principle options discussed in section 5.2.5.1 of Exhibit B-1 if BC Hydro uses customers whose primary space heating source is electricity as a proxy for customers without access to natural gas:**

   - **Under BC Hydro's proposed RIB rate pricing principle Option 1, no customer whose primary space heating source is electricity or low income customer whose primary space heating source is electricity will have a bill impact greater than 10 per cent (Exhibit B-1, Table 5-8);**

   - **Under RIB rate pricing principle Option 2, no customer whose primary space heating source is electricity or low income customer whose**

primary space heating source is electricity will have a bill impact greater than 10 per cent (Exhibit B-1, Figures 5-20 and 5-23).

The key issue for this phase 1 review is how to define customers without access to natural gas. As indicated at section 5.5.3 of Exhibit B-1, page 5-70, BC Hydro proposes a community approach to this issue, and will model the impacts of moving from the RIB rate to flat rate for customers in communities without access to natural gas (Exhibit B-1, page 5-71, lines 23-27).

Second, and only if the answer to the first question is yes for one or both of the residential customer segments, BC Hydro would report on Questions 4 and 5 as FortisBC has proposed. BC Hydro notes that FortisBC referenced a critical qualifier to the Question 4 and Question 5 examination, which is "within the existing regulatory environment". As noted by BC Hydro at pages 5-72 to 5-73 of Exhibit B-1, the phrase "within the existing regulatory environment" must take into account the F2017-F2019 rate caps set out in section 9 of Direction No. 7, and also the fact that the venue for any assessment of DSM program-related expenditures is a section 44.2 *UCA* DSM expenditure schedule determination filing. BC Hydro will be submitting a DSM expenditure schedule determination filing contemporaneously with or as part of the F2017 RRA filing in February 2017, and this filing must be considered as part of Questions 4 and Questions 5".

102.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-72

1.102.1 There does not appear to be a section addressing the portion of Question 5 regarding "what options there are for additional residential DSM program, including low income programs, within the current regulatory environment" (per lines 9-11). Is it BC Hydro's view that there are no options for additional DSM programs?

1.102.1.1 If yes, what is the basis for this conclusion?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.102.1.

102.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, pages 5-72

1.102.1 There does not appear to be a section addressing the portion of Question 5 regarding "what options there are for additional residential DSM program, including low income programs, within the current regulatory environment" (per lines 9-11). Is it BC Hydro's view that there are no options for additional DSM programs?

1.102.1.2 If no, please provide a response.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.102.1.

103.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-74 to 5-78

1.103.1 What percentage of low income (LICO and under) houses in BC Hydro's service area does 85,000 represent (per page 5-74)?

RESPONSE:

Of the about 170,000 low income customers estimated using LICO as the threshold, about 50 per cent have received ESKs.

103.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-74 to 5-78

1.103.2 Given the low income eligibility changes outlined on page 5-76, how many houses meeting the 2015 RDA definition of low income (LICO and under) have received ESKs since the program was launched in 2008?

RESPONSE:

It is not clear to BC Hydro if BCOAPO is asking BC Hydro how many additional ESKs would have issued if the July 2014 amendments to the DSM Regulation had been in affect at the time of the launch of the ESK offer in 2008. Undertaking such an exercise would be speculative. As noted in Exhibit B-1, page 5-74 lines 10 to 12, 89,971 ESKs have been distributed to BC Hydro low income customers from the program launch in 2008 to October 31, 2015.

103.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-74 to 5-78

1.103.3 How many of the approved ECAP applications were for houses with electric heat and, of these, how many received a high efficiency gas furnace?

RESPONSE:

Per the definition of "demand-side measure" found in subsection 1(1) of the *CEA*, actions which have the main purpose of encouraging a switch from one type of energy to another that would increase GHG emissions in B.C. are not considered "demand side measures". Accordingly, BC Hydro's DSM programs do not promote fuel switching from electricity to natural gas and none of the approved ECAP applications for houses with electric heat received a high efficiency gas furnace. BC Hydro works in collaboration with FortisBC to deliver the ECAP program and FortisBC has a current offer for a high efficiency gas furnace for gas heated homes.

103.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, page 5-74 to 5-78

1.103.4 Given the low income eligibility changes outlined on page 5-76, how many houses meeting the 2015 RDA definition of low income (LICO and under) have been approved for the ECAP and, of these, how many had electric heat and how many received a high-efficiency gas furnace?

RESPONSE:

Since the July 2014 low income eligibility changes made to the DSM Regulation, including the LICO x 1.3 eligibility criterion, 1845 participants completed ECAP basic and of these, 884 had electric heat. Note that this number is based off the LICO x 1.3 criterion.

BC Hydro does not provide high efficiency gas furnaces as part of its ECAP program. Please refer to BC Hydro's response to BCOAPO IR 1.103.3.

104.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6
BC Hydro Power Smart Home Loan Pilot Program Application

1.104.1 The BC Hydro Power Smart Home Loan Pilot Program was approved by the Commission on October 30, 2012 by Order G-162-12. Please advise when it was discontinued. Since the program was only available to credit-worthy applicants, please confirm that it was not targeted to assist Low income customers. Has BC Hydro considered such an (interest free) program for its low income customers?

RESPONSE:

BC Hydro respectfully submits that the three questions concerning BC Hydro's Power Smart Home Loan Pilot Program, which are asked in the context of the Minister RIB Report Letter (section 5.6 of Exhibit B-1), are of questionable or no relevance to the review of 2015 RDA Module 1 or the orders sought with respect to it, or for purposes of the Minister RIB Report Letter. Nevertheless, producing the requested information is not onerous and so to be responsive, BC Hydro advises:

Q1: The Power Smart Home Loan Pilot Program was discontinued on January 1, 2015.

Q2: Confirmed.

Q3: BC Hydro has not considered a program offering interest-free loans of up to $10,000 (the Power Smart Home Loan Pilot Program permitted eligible homeowners to borrow up to $10,000) to low income customers for purposes of energy efficiency upgrades.

104.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6
BC Hydro Power Smart Home Loan Pilot Program Application

1.104.2 Did BC Hydro's evaluation of US jurisdictions identify any interest free programs for low income customers?

RESPONSE:

BC Hydro's jurisdictional assessment of low income rates/low income terms and conditions/low income DSM programs is contained at Exhibit B-1, Appendix C-3D, pages 38 to 51 of 67. BC Hydro reviewed the low income DSM programs of Canadian jurisdictions but not of U.S. jurisdictions.

BC Hydro's general understanding is that similar to BC Hydro's ESK and ECAP low income DSM programs, many U.S. electric utilities offer their low income customers incentives for conservation. BC Hydro is not aware of specific U.S. electric utility DSM programs offering interest-free loans to low income customers for purposes of energy efficiency upgrades.

105.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.105.1 Please provide a copy of all Demand Side Management ("DSM"):

(a) Program planning documents prepared by or for BC Hydro since January 1, 2010 for any BC Hydro low income DSM programs; and
(b) Program evaluations prepared by or for BC Hydro since January 1, 2010 for any BC Hydro low income DSM programs.

RESPONSE:

The IR is asked in the context of the Minister RIB Report Letter (section 5.6 of Exhibit B-1). BC Hydro respectfully submits that the information sought in this IR, which is more relevant to a DSM expenditure schedule determination filed with the Commission under subsection 44.2(1)(a) of the *UCA* and is broad in scope, is of no relevance to the review of 2015 RDA Module 1 or the orders sought with respect to it, and of questionable relevance for purposes of the Minister RIB Report Letter. As noted in BC Hydro's response to BCOAPO IR 1.102.1, it has not been established that the RIB rate results in bill impacts of 10 per cent or greater for BC Hydro's low income customers. It is therefore premature to engage in review of BC Hydro's low income DSM programs as part of the RIB Report process.

Nevertheless, to be responsive for purposes of the RIB Report, BC Hydro attaches executive summaries of the following to this IR response:

- **Executive Summary, "Low Income Households Program – Energy Savings Kits: Impact Evaluation for F2009 and F2010", September 29, 2010 (Attachment 1); and**

- **Executive Summary, "Power Smart for Low-Income Housing: the Energy Conservation Assistance Program (ECAP): Program Evaluation F2010 and F2011", February 28, 2012 (Attachment 2).**

EXECUTIVE SUMMARY

Introduction

In 2007, the BC Provincial Government set out a plan to meet 50 percent of future resource needs through energy conservation by 2020. In partial support of this initiative, BC Hydro designed an energy acquisition program for low income residential customers in line with these long-range goals. Similar programs are widely available in many jurisdictions in North America and have been in place for three decades or more.

Reaching low income customers is important because of:

(a) ***The number of households*****.** Between 15 and 20 percent of BC Hydro residential customers are designated low-income. This translates to a population of approximately 260,000 low income households depending on prevailing socio-economic conditions.

(b) ***Special marketing considerations*****.** Low income customers face significant barriers to participation in conventional Demand Side Management (DSM) programs. Factors affecting participation include low disposable income and sub-optimal access to program information and financing (social marginalisation).

The Low Income Households Program offer includes Energy Saving Kits, Basic Retrofits and Advanced Retrofits with varying eligibility requirements for each of the three program components.[1] This evaluation focuses on the Energy Saving Kit (ESK) which is a package of basic, low-cost energy savings measures believed to be easily installed by any homeowner or tenant. The kit includes Compact Florescent Lights (CFL), faucet aerators, low flow shower heads, pipe wrap, caulking and draft proofing materials, outlet gaskets, window film and a number of smaller products and information on how to save energy in the home. The purpose of this document is to present an evaluation of the Energy Saving Kit component of the Power Smart for Low Income Households Program.

Program Rationale

As of March 31 2010, the LIHP has provided approximately 21,000 low income residential customers with greater awareness of inexpensive high-efficiency products and improved their access to information on how to save energy in their homes. The program rationale was examined using a program logic model, examining the linkages among inputs, outputs, purpose and goal for each activity. The logic model is consistent and reflects a strong program rationale.

Customer Survey

A detailed survey was conducted with 400 program participants covering a wide range of program attributes. When customers were asked how they became aware of the ESK offering the most important sources of customer awareness were BC Hydro billing statements (44%), friends and relatives (14%) and magazines and newspapers (12%). Customer satisfaction with various program components was particularly high with 89% of participants reporting either satisfaction or great satisfaction with the kits.

[1] The Energy Conservation Assistance Program (ECAP) provides free Basic and Advanced retrofits to customers with high electricity consumption. Services are provided through BC Hydro program contractors.

Energy and Peak Impacts

Gross and net energy savings were based on program activity in two fiscal years – one for the period April 1, 2008 through March 31, 2009 (F2009) and another for the period April 1, 2009 through March 31, 2010 (F2010) as shown in Tables 3.10 and 3.11 The evaluation estimated program impact in the following stages:

(a) ***Gross savings*****.** A pre and post experimental design with participant and non-participant groups (N=507) was used to compare pre-program and post-program measurements. Calculation of gross savings is then based on consumption comparisons between the participant and non-participant groups.

(b) ***Net savings (annual acquired rate)*****.** Net (evaluated) savings were estimated by modifying gross savings with free rider and participant spill over rates, calculated from survey response data. For F2009, evaluated energy savings are 0.9 GWh compared to gross savings of 1.2 GWh; evaluated peak savings are 0.4 MW compared to peak savings based on the program gross peak savings of 0.5 MW. For F2010, evaluated energy savings from new applicants are 1.4 GWh compared to gross savings of 1.9 GWh; evaluated peak savings were 0.6 MW compared to peak savings based on the program gross peak savings of 0.8 MW. The gross and net *cumulative* energy savings totals to F2010 are 6.2 GWh and 4.6 GWh respectively[2].

(c) ***Net savings (annual run-rate)*****.** Net (evaluated) savings were estimated by modifying gross savings with free rider and participant spill over rates, calculated from survey response data. For F2009, evaluated energy savings are 2.3 GWh compared to gross savings of 3.1 GWh; evaluated peak savings are 0.9 MW compared to peak savings based on the program gross peak savings of 1.3 MW. For F2010, evaluated energy savings from new applicants are 2.6 GWh compared to gross savings of 3.6 GWh; evaluated peak savings were 1.1 MW compared to peak savings based on the program gross peak savings of 1.5 MW.

[2] It is assumed that savings from F2009 will persist for up to 10 years at the full discounted rate in kilowatt-hours per year per participating customer (in F2009, the acquired saving for participants entering the program are lower due to adjustments for the date kits were actually installed). For customers who received their kits during F2009, evaluated energy savings in F2010 are 2.3 GWh = 241 kWh x 9,364 compared with gross savings of 3.1 GWh = 329 kWh x 9,364. These amounts are added to the savings attributed to the program by participants entering the program during F2010 for net and gross calculations respectively. The cumulative totals are: 1.2+1.9+3.1=6.2 GWh (gross) and 0.9+1.4+2.3 = 4.6 GWh (net)).

EXECUTIVE SUMMARY

Introduction

In 2007, the BC Provincial Government set out a plan to meet 50 percent of future resource needs through energy conservation by 2020[1]. In partial support of this initiative, BC Hydro designed an energy savings acquisition program for low-income residential customers identified under the Statistics Canada Low-Income Cut-off (LICO). Low-income customers face significant barriers to participation in conventional Demand Side Management (DSM) programs. Factors affecting participation include low disposable income and sub-optimal access to program information and financing (social marginalization). Similarly defined programs are available in other North American jurisdictions such as California, Wisconsin, New York State and Québec.

The BC Hydro Power Smart Residential Low-Income Housing Program (PSLIHP) is intended to generate significant energy savings, contribute to BC Hydro energy savings goals and support the conservation targets of the provincial government's Energy Plan. In summary, the primary objectives of the program are to:

1. Make energy efficiency more accessible to low-income customers;
2. Provide energy savings for BC Hydro;
3. Provide low-income customers with energy-efficient technologies that reduce energy consumption and lower utility bills; and
4. Increase knowledge and awareness of energy efficiency among low-income customers.

The PSLIHP provides some low-cost energy savings measures that are easy to install by a homeowner or tenant. These are packaged into an Energy Saving Kit (ESK) which includes CFL lamps, faucet aerators, low-flow shower heads, pipe wrap, caulking and draft proofing materials, outlet gaskets, window film and a number of additional measures as well as tips on saving energy in the home.

Further offerings are delivered through the Energy Conservation Assistance Program (ECAP). The ECAP provides qualified low-income BC Hydro residential account holders with a home energy evaluation, the installation of additional energy saving products such as energy-efficient refrigerators and personalized energy efficiency advice. All services and equipment are supplied free of charge to the participant. Of eligible low-income customers, approximately 47% own and inhabit electrically heated single-family dwellings eligible for further retrofits under the basic or advanced stream of the ECAP[2]. The advanced stream includes basic offerings but adds a comprehensive home insulation program. Other low-income customers such as renters or those living in natural gas heated dwellings remain eligible for the basic program stream.

In fiscal year 2010, the program commenced in May 2009 and totalled 607 ECAP participants of whom 534 (87.9%) received basic stream deliverables and 73 (12.1%) received the advanced. Fiscal year 2011 ran for a full 12 months and counted 1,719 participants consisting of 1,659 basic (96.5%) and 60 advanced (3.5%) program deliveries. The two-year total for fiscal years 2010 and 2011 was 607 (26%) and 1,719 (74%) respectively for 2,326 program completions in all.

[1] This plan was updated in the Fiscal 2011-2014 BC Hydro Service Plan to provide for 66% of future resource needs.

[2] BC Hydro Residential End-use Survey (2010)

The purpose of this document is to present an evaluation of ECAP for the fiscal years 2010 and 2011.

Program Rationale

As of March 31 2011, ECAP installed energy-efficient products in the homes of approximately 2,300 low-income residential customers and provided them with personalized energy efficiency advice. The program rationale is expressed through a program logic model which describes the linkages between inputs, outputs, purpose and goal for each activity (§3.1). The model is consistent and provides a sound program rationale.

Customer Survey

A detailed telephone survey of program participants conducted in June 2011 resulted in 300 interview completions. The response rate was an acceptable 15% of 2,000 participants polled and proportional representation by region and dwelling type was very good[3]. When customers were asked how they first became aware of the ECAP offering the most prevalent sources of customer awareness were building managers (25%), BC Hydro billing statements (25%), friends and relatives (10%) and the BC Hydro Website (9%). Ratings of the various program components were particularly high with 92 percent of respondents rating the overall quality of the work done by the contractor as either “excellent” or “good”.

Methodology

Energy savings have been estimated for program activity in fiscal years 2010 and 2011. Any naturally occurring conservation was accounted for in the gross savings calculations through the employment of participant and control groups. Initial gross savings estimates were calculated using a pre and post experimental design. The assumption is that, if the program and comparison groups are sufficiently comparable, any difference in outcome between the two groups may be attributed to the program. The program and comparison groups were compared across selected strata such as geographic location, program stream and dwelling type. A total of 448 participating households and 119 non-participating households were used to generate the final samples. Average pre-program consumption for program participants and non-participants was comparable at 15,142 kWh and 15,011 kWh per year respectively. The difference between these values is not statistically significant[4], and consumption for both groups follows similar exponential distributions.

Re-sampling with replacement and bootstrapping techniques were applied to achieve sample equivalency with population strata.

[3] See § 2.2 for more details regarding survey demographics.

[4] This is established by the fact that the 95 percent confidence interval for mean participant consumption (15594, 14690) includes the consumption value for non-participants (15,011).

Energy Impacts

Gross and net energy savings were based on program activity in two fiscal years – one for the period April 1, 2009 through March 31, 2010 (F2010) and another for the period April 1, 2010 through March 31, 2011 (F2011) as shown in Table 3.7. The evaluation estimated program impact in the following stages:

1. **Gross savings.** A pre and post experimental design with participant and non-participant groups was used to compare pre-program and post-program metrics including electricity use. The gross savings were approximately 0.5 GWh for F2010 and 1.5 for F2011.
2. **Net savings (annual run-rate).** Since both free rider and spillover rates were assumed to be zero, gross and net savings are identical. Evaluated net energy savings for F2010 are therefore 0.5 GWh compared to reported gross savings of 0.4 GWh and 1.5 GWh compared to 1.4 GWh for F2011.

Conclusions

Although average savings per household were validated, program participation was significantly below expectation for both fiscal years examined in this report. Approximately 3,750 basic and 1,500 advanced program deliveries (5,250 in total) were anticipated by the end of fiscal year 2011[5]. These business case projections were based on results from programs with some market history such as the California Low Income Energy-Efficiency Program. Actual participation was much lower with only 2,193 basic and 133 advanced program completions (2,326 in total).

Better penetration and understanding of the target market would result in a higher program participation rate and savings value. A possible barrier to higher penetration levels in British Columbia may be the difficulty in identifying low income customers in electrically heated homes who require significant insulation upgrades. As this may be the result of insufficient outreach methods, a rigorous process review might identify important areas for improvement. Finding the detail for such a review requires more program experience.

This process review should precede any further impact assessment of ECAP by program stream.

[5] Longland (2008) p 33

106.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.106.1 Please provide all studies, reports, evaluations or other written documents of any nature within the custody or control of BC Hydro, prepared since January 2005 regarding the extent of the following DSM market conditions experienced by low income households in British Columbia:

(a) High initial capital costs of energy efficiency investments;
(b) Lack of access to capital for energy efficiency investments;
(c) High implicit discount rates/payback periods for energy efficiency investments;
(d) High proportion of low income renters;
(e) Split incentives between landlord and tenants relative to energy efficiency investments; and
(f) High mobility rate of low income renters.

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the information sought is not relevant to and cannot aid in the review of the 2015 RDA or the orders sought in respect of it, or for purposes of the Minister RIB Report Letter.

The requested information is broad in scope temporally and geographically- "all studies, reports, evaluations or other written documents of any nature within the custody or control of BC Hydro" over the last decade, regarding "DSM market conditions experienced by low income households in British Columbia", thus including portions of the Province outside of BC Hydro's service area. An inquiry into "DSM market conditions experienced by low income households in British Columbia" amounts to a virtually unconditional examination of the establishment of BC Hydro's low income DSM programs. Even a generous reading of Minister RIB Report Letter Questions 4 and 5 cannot support such an inquiry.

107.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2

1.107.1 Please provide the sections of BC Hydro's Conservation Potential Reviews, if any, that informed the two residential low income DSM program offerings.

RESPONSE:

BC Hydro notes that this IR is asked in the context of the Minister RIB Report Letter. Responding to Questions 4 and 5 of the Ministers RIB Report Letter does not entail justifying the basis upon which BC Hydro established existing low income DSM programs in 2008 (ESK) and 2009 (ECAP). To be responsive BC Hydro offers the following. The 2007 CPR identified core areas of focus for improvements in the residential market such as lighting, insulation, refrigeration and behavior but it did not specifically inform the two low income program offerings as CPR data is not segmented by income.

107.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2

1.107.2 What programs currently exist that may be able to assist low income BC Hydro ratepayers with paying their BC Hydro electricity bills?

RESPONSE:

Participation in Residential DSM programs helps to reduce consumption which in turn helps to reduce a customer's bill. BC Hydro acknowledged in its 2015 RDA that low income customers may not readily access all of its Residential DSM programs. However, BC Hydro has two DSM programs specifically targeted at low income customers: ESKs and ECAP, which collectively have provided nearly half a million dollars in electricity cost savings to low income customers.

While not specifically targeted at BC Hydro low income customers, the majority of such customers are better off under the RIB rate as compared to a flat rate alternative.

BC Hydro has other ways to assist customers with managing their bills such as: billing plans (Equal Payment Plan and Pay As You Go), installment plans and payment deferrals. Please refer to Exhibit B-1, section 8.6.2.1 for more detailed information on these existing measures that also benefit low income customers.

Finally, BC Hydro is exploring potential low income terms and conditions, please refer to Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

108.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Savings Kits

1.108.1 Please explain the methodology used in evaluating the savings achieved by ESKs given the fact that each kit contains a number of components, some of which the customer may not be able to install.

RESPONSE:

The methodology used to estimate savings for an ESK uses a combination of: (1) engineering estimates for the amount of energy saved for each product within the kit; (2) an estimate of the install rates of each product based on customer survey responses to questions in this regard; (3) an estimate of the primary fuel used for space and water heating at the residence; and (4) billing analysis of a sample of past participants.

108.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Savings Kits

1.108.2 Please confirm that until recently BC Hydro's website contained a section with the heading "Are you a low income BC Hydro customer? We can help you save $30 a year."

RESPONSE:

Confirmed.

108.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Savings Kits

1.108.3 Please further confirm that by letter dated February 13, 2015 BC Hydro advised BCPIAC that "[T]he website headline 'We can help you save $30 a year' refers to the average electricity savings from ESKs. It is based on the blended average annual savings of the two current types of kits (standard and apartment). The cost of electricity assumed is $.0827/kWh based the residential exempt rate (Rate Schedule (RS) 1151 as of April 1, 2013)".

RESPONSE:

Confirmed.

108.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Savings Kits

1.108.4 At p.5-75 of the Application, BC Hydro asserts that "The energy savings kits referred to above can help recipients save up to $100/year on utility bills." Please explain how the savings more than tripled, and provide a working spreadsheet that identifies the energy saved by individual components of the ESK, and the value of that energy, for both the $30 and the $100 annual savings calculation.

RESPONSE:

This IR appears to be based on a misunderstanding of what the $100/year and $30/year savings estimates represent. The <u>up to</u> $100/year figure referenced at page 5-75 of Exhibit B-1 is based on the estimate of the maximum savings potential of a customer with electric space heating and electric hot water heating that installs all of the products provided in an ESK. The $30/year figure referenced in the question is the <u>average</u> savings of an ESK based on install rates and type of fuel used for space and water heating.

BC Hydro respectfully declines to provide the requested working spreadsheet that identifies the energy saved by individual components of the ESK program on the basis that the requested spreadsheet is not relevant to and cannot aid in the review of the 2015 RDA or the orders sought in respect of it, or for purposes of the Minister RIB Report Letter.

108.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Savings Kits

1.108.5 Please provide the cost of both types of ESKs to BC Hydro, together with the cost of third party delivery.

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the information sought is not relevant to and cannot aid in the review of the 2015 RDA or the orders sought in respect of it, or for purposes of the Minister RIB Report Letter. The information sought in this IR, which concerns the costs of BC Hydro's ESK DSM program, is more relevant to a DSM expenditure schedule determination filed with the Commission under subsection 44.2(1)(a) of the *UCA*. As noted in BC Hydro's response to BCOAPO IR 1.102.1, BC Hydro will be submitting a DSM expenditure schedule filing contemporaneously with or as part of the F2017 RRA in February 2016.

108.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Savings Kits

1.108.6 Please provide the annual cost of the ESK program for each year since 2008, by cost type, together with BC Hydro's estimate of energy saved.

RESPONSE:

BC Hydro respectfully declines to respond to this IR for the reason set out in BC Hydro's response to BCOAPO IR 1.108.5.

108.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Savings Kits

1.108.7 Please provide BC Hydro's forecast program expenditures on ESKs for future years, together with its estimate of energy savings.

RESPONSE:

BC Hydro respectfully declines to respond to this IR for the reason set out in BC Hydro's response to BCOAPO IR 1.108.5.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.1 Please confirm that Carillion Canada Inc. is the program contractor for ECAP. Are there any other contractors involved in the delivery of ECAP?

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the information sought is not relevant to and cannot aid in the review of the 2015 RDA or the orders sought in respect of it, or for purposes of the Minster RIB Report Letter. The IR is asked in the context of the Minister RIB Report Letter (section 5.6 of Exhibit B-1). Information concerning the identity of and other aspects of contractor(s) for BC Hydro's ECAP program, including when and by what process such contractor(s) were selected, and how many assessments such contractor(s) may have performed since the inception of the ECAP program in May 2009 (BCOAPO IRs 1.109.2 and 1.109.3), is not relevant to Minister RIB Report Letter Questions 4 or 5.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.2 When was Carillion appointed, and what document, if any, did BC Hydro publish (such as a RFP) to elicit responses from interested parties? Please provide a copy of any such document.

RESPONSE:

BC Hydro respectfully declines to respond to this IR for the reason set out in BC Hydro's response to BCOAPO IR 1.109.1.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.3 How many assessments has Carillion performed since the inception of the program? Please provide an analysis by year and service area.

RESPONSE:

BC Hydro respectfully declines to respond to this IR for the reason set out in BC Hydro's response to BCOAPO IR 1.109.1.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.4 The ECAP application form states: "BC Hydro and FortisBC are not obligated to provide program support to any applicants including those who meet all program eligibility criteria. It is within BC Hydro's and FortisBC's sole discretion to accept or reject any applicant who meets all program eligibility criteria". Please provide all circumstances under which BC Hydro might reject an otherwise qualified application, and provide the numbers of such applications rejected by year, by service area and reason, for all years since ECAP started.

RESPONSE:

This language is intended to protect BC Hydro and FortisBC from unforeseen situations or circumstances where offering ECAP may not be in the utilities best interest, such as, but not limited to the health and safety of contractors who would install the energy efficient upgrades. As these situations are unforeseen, no list of circumstances exists; rather, program staff and senior management would use their judgement of a situation or circumstance to render a decision. To date, no applications of customers meeting all program eligibility criteria have been rejected.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.5 Please provide details of how the savings referred to on p.5-75 of the Application of $150 per year for basic measures and a fridge, and $300 per year for insulation upgrades were calculated. Please also clarify whether the $300 referred to at p. 5-75 (line 4) is the total annual saving from all three sources or is simply referring to insulation savings.

RESPONSE:

The savings referenced on page 5-75 of Exhibit B-1 were calculated as follows:

- **The figure of $150/year in savings is based on a potential basket of energy saving measures that could be installed in a single family home with electric space heating and electric hot water heating. It assumes specific ECAP eligible energy savings measures (including a fridge, CFLs, showerheads, faucet aerators, door weatherstripping) are installed replacing existing inefficient options. The savings per measure are based on engineering estimates;**

- **The figure of $300/year in savings is based on insulation and air sealing savings only. The insulation savings are based on the program's average savings estimate for a single family electrically heated home.**

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.6 Please provide the annual cost of the ECAP program for each year since 2008, by i) direct cost type (home evaluation, energy saving products, refrigerators and insulation); and ii) indirect cost type (administration, marketing, etc.). Please also provide BC Hydro's estimate of energy saved by program component.

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the information sought is not relevant to and cannot aid in the review of the 2015 RDA or the orders sought in respect of it, or for purposes of the Minister RIB Report Letter. The information sought in this IR, which concerns the costs of BC Hydro's ECAP program, is more relevant to a DSM expenditure schedule determination filed with the Commission under subsection 44.2(1)(a) of the *UCA*. As noted in BC Hydro's response to BCOAPO IR 1.102.1, BC Hydro will be submitting a DSM expenditure schedule filing contemporaneously with or as part of the F2017 RRA in February 2016.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.7 Please provide BC Hydro's forecast program expenditures on the ECAP program for future years. Please also provide BC Hydro's estimate of energy savings by program component.

RESPONSE:

BC Hydro respectfully declines to respond to this IR for the reason set out in BC Hydro's response to BCOAPO IR 1.109.6.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.8 BC Hydro states that it conducted an evaluation of its ECAP program in 2011, a summary of which is included in the F2012 Demand Side Management Milestone Evaluation Summary Report to the BCUC. At line 22 of p. 13 of this report, BC Hydro refers to a study that analyzed the energy savings impact of ECAP and summarized the results. In order to evaluate the program, please provide the actual study, particularly sections that discuss the electricity use metrics of households in their pre and post experimental design with participant and non-participant groups.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.105.1, which provides the executives summaries only for the reasons stated in that response.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.9 Please confirm whether BC Hydro has conducted a new evaluation of ECAP, given that this evaluation is 4 years old and that the program has gone through significant changes over those 4 years.

RESPONSE:

Not confirmed. It is not accurate to say that ECAP has gone through significant changes over the past four years as all the core elements of the program remain the same even if eligibility has changed as a result of the July 2014 DSM Regulation amendments. No new evaluation has been conducted over the last four years.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.10 How many ECAPs is BC Hydro capable of completing per year?

RESPONSE:

BC Hydro's current plan is capable of delivering approximately 1,550 ECAP units for F2016.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.11 Does BC Hydro have a target number for ECAPs to complete per year? If so, what are those targets?

RESPONSE:

The BC Hydro ECAP target for F2016 is to complete 1,500 basic units and 50 advanced units.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.12 If BC Hydro has targets, are BC Hydro and its contractors able to process more than the target number of ECAP applications per year?

RESPONSE:

Yes. With additional resources BC Hydro and its contractors could process more than the target number of ECAP applications. However, to meet BC Hydro's current targets already requires heavy and concerted efforts with a range of partner organizations to recruit customers into the program. To date eligible customers have not been denied access to the program.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.13 How many ECAP applications were turned down in 2015, 2014, and 2013, and for what reasons?

RESPONSE:

The table below shows the number of applicants declined on the basis of eligibility, including not meeting consumption requirement, income exceeding thresholds, home already received ECAP and ineligible dwelling type.

Year	# Declined
F2013	304
F2014	213
F2015	122

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.14 Is the primary goal of ECAP to provide BC Hydro with energy savings, or is the primary goal to significantly reduce bills for low income customers who are having difficulty paying their electricity bills?

RESPONSE:

The goal of ECAP is to reduce energy consumption and lower bills for low income customers.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.15 Does BC Hydro do a meter reading before and after installation of ECAP measures in order to determine whether ECAP has resulted in energy and bill savings for residential customers?

RESPONSE:

No.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.16 How does BC Hydro verify income information without violating privacy laws when determining low income customers' eligibility for ECAP?

RESPONSE:

Please refer to section 5.1 of Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

109.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Energy Conservation Assistance Program (ECAP)

1.109.17 When BC Hydro collects customers' income data for determining eligibility for ECAP, does BC Hydro keep customer income data separate from the main customer service system?

RESPONSE:

The DSM Regulation sets out that eligible low income households must provide either tax information or proof of receipt of the various categories of social assistance laid out of the definition of "low income household". Where BC Hydro collects tax-related income for ECAP purposes, it is kept separately from the customer service system.

Please refer to section 5.1 of Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

110.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.110.1 For each month for the most recent twelve months available, disaggregated by heating and non-heating residential accounts, please provide:

(a) The average bill for residential accounts at existing rates provided in sufficient detail (including all input variables) to permit replication; and
(b) The same bill information using BC Hydro's rates as of April 1, 2016.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.74.1.

111.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.111.1 Please provide all empirical studies within BC Hydro's custody or control showing the relationship between income and electricity consumption, using data from:

(a) BC Hydro's customers;
(b) A Canadian electric utility, whether or not in British Columbia; and
(c) Any electric utility whether or not Canadian.

RESPONSE:

Income-Consumption

A copy of BC Hydro's 2013 RIB Evaluation Report is found at Exhibit B-1, Appendix C-3B. The 2013 RIB Evaluation Report found that average per-capita disposable income for the Province of B.C. has a statistically significant effect on consumption. This result can be interpreted as a measure of the effect of the economy on residential electricity consumption.

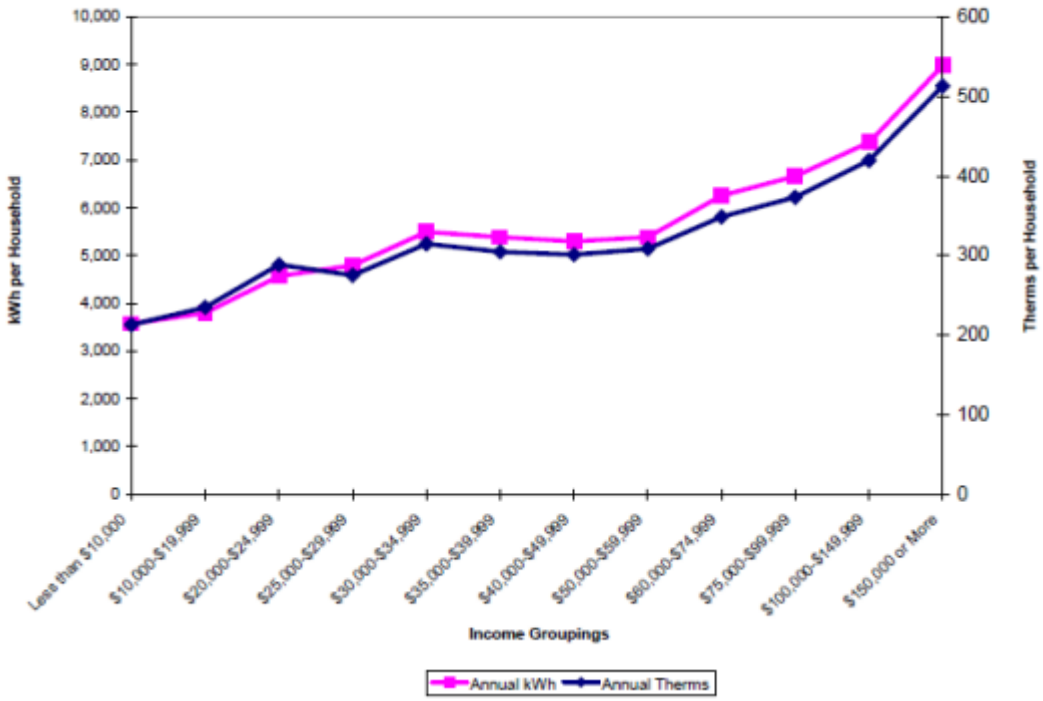
The results of the 2014 REUS found at Exhibit B-1, Appendix C-3F indicate that electricity consumption varies with household income (i.e., overall, there is a positive correlation). This relationship is statistically significant. It does not imply that higher income causes higher consumption. Note that other factors, such as housing type and heating fuel type, are also positively correlated with consumption.

Other jurisdictional reviews that BC Hydro is aware of on this topic are as follows.

The OEB as part of its 2008-2011 public engagement respecting LEAP stated that "a correlation between low-income and consumption … has not been established" (OEB, EB-2008-01050), *Report of the Board: Low-Income Energy Assistance Program* (10 March 2009), page 6; http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2008-0150/Board_Report_LEAP_20090310.pdf.

In 2012 the CPUC Policy and Planning Division conducted a literature review on electricity use and income. Included in the review is the relationship between residential average electricity usage and income in California depicted in Figure 1.

Figure I. Average Electricity and Natural Gas Consumption by Income



http://www.cpuc.ca.gov/NR/rdonlyres/609BC107-EF3C-4864-AD56-E964884D51AC/0/PPDElectricityUseIncome.pdf.

Income-Price Responsiveness

In addition to analyses of the relationship between usage levels and income levels, there have been numerous studies on the correlation of income and the price responsiveness of residential customers. As part of an effort to better understand how inclining block rates impact consumption, BC Hydro asked its consultant E3 to review the literature concerning the correlation between income and price elasticity. Papers in this area of research include:

- **Reiss and White (2005) found that income effects on own-price electricity demand elasticity were negligible and statistically insignificant;**
- **Baker, Blundell, and Micklewright (1989) estimated own-price elasticities for the top, middle, and lowest income deciles. Their electric price elasticity estimates are fairly constant across the three income categories, with the middle income category displaying the most price responsiveness;**
- **Faruqui and George (2005) find evidence that higher-income households are more price responsive to critical peak pricing than lower-income**

households. The study compares the responsiveness of the income groups of $40,000 and $100,000 annual income. It does not statistically isolate the income effect from other variables such as Central A/C ownership, spa ownership and education level.

Citations:

1. **Baker, P., R. Blundell, and J. Micklewright (1989) "The Microeconometric Approach to Modeling Energy Demand: Some Results for UK Households," *The Economic Journal,* 99: 720 – 738 (Attachment 1).**
2. **Faruqui, A. and S. George (2005) "Quantifying Customer Response to Dynamic Pricing," *Electricity Journal*, 18(4): 1040 – 6190 (Attachment 2).**
3. **Reiss P.C. and M.W. White (2005) "Household Electricity Demand, Revisited," *Review of Economic Studies*, 72: 853-883 (Attachment 3).**

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MODELLING HOUSEHOLD ENERGY EXPENDITURES USING MICRO-DATA*

Paul Baker, Richard Blundell and John Micklewright

Energy – one of the major headings of consumer expenditure – has experienced considerable change in price in the last 15 years. The 1970s and early 1980s saw large increases relative to prices of other goods, although more recently energy prices have dropped back with the world recession and associated energy glut. Furthermore, during this period, movements in prices within the overall fuel heading have been far from uniform – the relative price of gas to electricity in the United Kingdom fell markedly through the middle and late 1970s before rising sharply in 1981/2.

Many attempts have been made to model the effect of the price changes on domestic demand both for the total of all forms of energy and for specific types of fuel. The bulk of this effort in the United Kingdom has concentrated on modelling aggregate demand, rather than looking at how individual households have adjusted their consumption patterns (see Westoby, 1983, for a review).[1] However, much policy discussion of energy suffers in the absence of microeconometric evidence. Would governments in the 1970s and early 1980s have engineered the same sorts of relative price changes via their control of nationalised supply industries had they known how different households might respond? Do different age groups or birth cohorts have different preferences regarding temperature in the home, making forecasting with aggregate models too crude a method? Interest in such questions is further stimulated by current policy on privatisation of supply industries and harmonisation of EEC VAT rates (gas and electricity in the United Kingdom are at present zero-rated). They force attention onto the modelling of individual household demands with microdata, and it is this which forms the subject of this paper.[2]

Consumers' demand for fuels is best viewed within a household production framework where the underlying demands are for services such as heat, light,

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[1] An exception is Hutton (1983, 1984) who models total expenditure on fuel with a single year of FES data. Some preliminary unpublished work was reported in Isherwood and Hancock (1979).

[2] The situation in Britain contrasts with that in the United States where there has been a developing microeconometric energy literature in recent years. Much of the early United States work was concerned with modelling households' responses to time-of-day (TOD) electricity pricing, with data generated by a number of controlled experiments in different states (the inaugural Annals issue of the *Journal of Econometrics* was devoted entirely to this subject, being followed by a further collection of papers on the same topic in 1984). More recently, the focus has been on broader issues such as the joint determination of stocks of durable energy-consuming appliances and their utilisation, e.g. Dubin and McFadden (1984), Dubin (1985). See also Cowing and McFadden (1984) for a detailed analysis of two microsimulation models of household energy demand used by the supply industries.

refrigeration, etc. To obtain these requires two things: a durable appliance to produce the service and a fuel to power the appliance. Demand for energy is thus a joint demand for an appliance stock and for its rate of use.[3] Changes in fuel prices should affect both the rate of use of an appliance and the decision about durable ownership itself, the latter being determined by a trade-off between capital and operating costs.

A number of United States studies have made impressive attempts to model the joint determination of appliance demand and use with micro data on households; e.g. Hausman (1979), Dubin and McFadden (1984) and Dubin (1985).[4] However, a number of problems stem from the often severe data requirements (e.g. Dubin, Chapter 2) and assumptions about price expectations and the housing market (e.g. Dubin and McFadden, pp. 350–1). There is also the question of those households whose durable choice is constrained by their tenure type – the studies just mentioned are all restricted to owner occupiers. Given the lack of micro level research into energy demand in the United Kingdom, we concentrate in the present paper on modelling expenditure on different fuels conditional on durable ownership, leaving the question of ownership to a separate paper (Baker *et al.* 1987*b*). This allows us to consider the conditional demands in more detail than typically occurs in the joint models of appliance choice and use. In particular, we allow the marginal rate of substitution across disaggregated energy demands to differ across households with different durable stocks. As a result although energy demands are modelled conditional on durable stocks, they are not assumed to be separable from these stocks. The pedigree of this approach is well established, as evidenced by the earlier United States literature, e.g. McFadden *et al.* (1977), Lawrence and Braithwait (1979), Hausman *et al.* (1979), Caves and Christensen (1980).

The *way* in which expenditure information is collected in our data has important consequences for our modelling. Data are drawn from the annual *Family Expenditure Survey* (FES) of Great Britain. We pool data from the surveys for the years 1972–83, obtaining a sample of over 80,000 households.[5] To our knowledge, the FES is the only annual national survey to collect detailed information from individual households about expenditures on different types of fuel, with separate headings for gas, electricity, coal, coke, central heating oil, paraffin and 'other' fuels (this includes calor gas and firewood). In general, expenditures are recorded in 'diaries' kept over a two week period. In the case of fuels, this only applies to expenditures on coal and coke, oil (prior to 1977), paraffin, and other fuels. The situation is different for gas and electricity for which quarterly bill payments are amongst the few items of expenditure in the FES that are requested outside of the diaries and in principle, there is complete

[3] This jointness of demand is found, of course, in other areas of consumer choice, notably housing which can be viewed as a joint decision of tenure type and housing expenditure, e.g. King (1980).

[4] The analysis can proceed at different levels depending on whether the researcher merely allows for correlation between the error terms in reduced form durable and usage equations or whether a more structural approach is adopted in which it is recognised that estimated equations are based on maximisation of the same utility function and thus have parameters in common.

[5] A fuller account of the data can be found in Baker *et al.* (1987*a*).

coverage in the survey of gas and electricity expenditures at the household level. The remaining fuels, by their nature, are all fuels that tend to be bought in bulk and at infrequent intervals. This means that we observe some households in the FES who consume these fuels but who have no recorded expenditure, although we cannot distinguish them from those who genuinely do not consume. Others are observed with recorded expenditures which are larger than their average fortnightly outlay on the fuel in question. This problem of infrequency of purchase is sufficiently severe to leave the measured households' fortnightly expenditures on these fuels as exceptionally noisy measures of their consumption during this period. Although structural models of purchase infrequency are available (see Blundell, 1988), the problem is likely to be so severe in this case that in the development of our theoretical and empirical model, we treat consumption of these fuels as unobservable.[6]

In Section I we present a two-stage budgeting model of energy demand which reflects the characteristics of the data discussed above. Section II contains empirical results for household gas and electricity expenditures, the form of the estimated equations being an approximation to those indicated by our theoretical model. The estimated price and income effects are found to display considerable variation across different household types. This in turn has important implications for welfare measurement, forecasting and on the nature and stability of the aggregate relationship between energy demand, prices and income. Section III concludes. The work presented in the paper represents only a partial step towards answering the questions about government policy raised above. However, it illustrates the advantages of using a rich micro data set to analyse the energy demand of the household sector.

I. CONSUMER DEMAND THEORY AND ENERGY EXPENDITURES

(a) *A Two Stage Budgeting Model*

The theoretical model we develop serves two purposes. First, it allows us the possibility of constructing a constant utility based measure of household welfare which could be used to identify the welfare costs and benefits of energy price changes and subsidies paid to particular energy items. Second, it helps in designing an appropriate econometric specification of the energy demand equations.

In this model the consumption of fuels (or energy goods) is split into three groups (q_e, q_g and q_o) representing electricity, gas and other fuel respectively. Although our data provide reasonably accurate measures of expenditure on

[6] Throughout the data-period used in our research, the cash amounts (inclusive of standing charge) of the last gas and electricity bills are requested. If payment is by slot meter then the expenditures do enter the diaries, but there is not the same problem of infrequency, since consumption within the diary fortnight is directly determined by the amounts fed into the meter during this time. Some households pay neither by quarterly bill nor by slot meter, but by budget scheme whereby a regular monthly payment is made followed by an end-of-year adjustment. However, such households still receive a quarterly advice showing the value of consumption. The amount of the last advice is recorded in the FES and is treated by us as equivalent to a bill. Note too that the value of slot meter rebates in the last 12 months is also recorded. We only observe the split of electricity expenditure into standard and cheap rate in certain years.

electricity and gas, we have noted that expenditures on other fuels are subject to large measurement error due to the severe lumpiness in purchases. We limit ourselves to the extreme case where we treat other fuel expenditure *and* therefore total fuel expenditure as *unobserved*. This leads us to consider the assumptions under which household preference parameters can be identified despite the lack of observations on total fuel expenditure. Our starting point is a two-stage budgeting framework.

Under two-stage budgeting, expenditure decisions on fuels and all other non-fuel goods can be represented by a recursive structure *as if* the household first allocated income between fuels and non-fuels and then at a second stage chose its disaggregated fuel expenditures. The restriction that two-stage budgeting imposes on household behaviour is shown in the following expenditure system

$$e_j = f_j(p_e, p_g, p_o, x) \quad j = e, g \quad \text{and} \quad o \tag{1}$$

where e_j and p_j are the expenditure and price for the jth fuel and x is total energy expenditure. Disaggregated fuel expenditures depend only on relative fuel prices and total fuel expenditure. This is equivalent to assuming weakly separable household preferences between fuel and non-fuel goods (see Deaton and Muellbauer, 1980*a*). In this case we can express utility over all goods as $U[U_f(\mathbf{q}^f), \mathbf{q}^n]$, where $\mathbf{q}^f$ is the vector of energy goods and $\mathbf{q}^n$ is the vector of all non-fuel goods *excluding* durables. As we have already discussed, we consider household durable stocks in a rather different light since these cannot be reasonably considered weakly separable from energy consumption.[7]

Since we assume that e_o (and therefore x) to be unobserved, an expression for x must be found. Defining y to be household net income and p_N to be the price index for the composite of all non-fuel goods, the first stage of the two stage budgeting rule can be expressed as

$$x = g(p_e, p_g, p_o, p_N, y). \tag{2}$$

Substituting (2) in (1) for $j = e$ and g generates 'estimating' equations of the form:

$$e_j = \tilde{f}_j(p_e, p_g, p_o, p_N, y) \quad \text{for} \quad j = e \quad \text{and} \quad g. \tag{3}$$

To parameterise (3) a functional form for preferences is required. For the within fuel expenditures we assume quasi-homothetic preferences with the implication that the cost of achieving a level of utility $U_f(\mathbf{q}^f)$ is

$$C(\mathbf{p}^f, U_f) = a(\mathbf{p}^f) + b(\mathbf{p}^f)\, U_f(\mathbf{q}^f) \tag{4}$$

where $a(\cdot)$ and $b(\cdot)$ are both linear homogeneous convex functions of the vector of fuel prices $\mathbf{p}^f$. Indeed, $b(\mathbf{p}^f)$ can be thought of as the price index for 'supernumary' fuel expenditures above a 'necessary' level given by $a(\mathbf{p}^f)$. As we mentioned above, energy commodities enter a household production

[7] The possibility that these durable conditioning variables may be endogenous can be assessed with an exogeneity test in the empirical specification of the demand equations. We do not explore this issue in this paper, although it will be the subject of future research, thus tying in our separate work on ownership of durables.

process whose outputs are heat, light and power. For this reason it is unlikely that the energy inputs themselves are separable and our functional form for $a(\mathbf{p}^f)$ described below is chosen to reflect this.

Differentiating the cost function (4) with respect to price and substituting out the utility term U_f using the identity that $C(\cdot) \equiv x$ gives the following Marshallian demands

$$e_j = p_j a_j(\mathbf{p}^f) + p_j b_j(\mathbf{p}^f) \frac{[x - a(\mathbf{p}^f)]}{b(\mathbf{p}^f)} \quad \text{for} \quad j = e, g \quad \text{and} \quad o, \tag{5}$$

where $a_j(\mathbf{p}^f)$ and $b_j(\mathbf{p}^f)$ refer to the corresponding price derivatives of $a(\cdot)$ and $b(\cdot)$ respectively. The expenditure system (5) corresponds to the expenditure equations (1) above. The term $[x - a(\mathbf{p}^f)]/b(\mathbf{p}^f)$ can be thought of as real supernumerary fuel consumption and the term $p_j a_j(\mathbf{p}^f)$ is simply the necessary expenditure on fuel j. Imposing Stone-Geary preferences on (5) would restrict $a_j(\mathbf{p}^f) = \alpha_j$ and $p_j b_j(\mathbf{p}^f)/b(\mathbf{p}^f) = \beta_j$ where both α_j and β_j are constant parameters, thus yielding the familiar Linear Expenditure System (LES). The form (5) generalises this additively separable specification by allowing all fuel prices to influence necessary expenditures on any one and by allowing the marginal budget shares to be price dependent. The well known drawbacks of the additivity assumption implicit in the LES are thus avoided (see Deaton, 1974).

Equation (5) represents the second stage in the recursive two-stage budgeting structure described above. At the first stage, apart from the pre-committed energy expenditure $a(\mathbf{p}^f)$, supernumerary income $y - a(\mathbf{p}^f)$ must be allocated between supernumerary energy consumption and other goods. We again use the cost function to represent preferences, the functional form of which is guided by our priors about the shape of the Engel Curve relating total energy expenditure to net income. It seems appropriate at this first stage allocation to allow for an explicit non-linear relationship between x and $y - a(\mathbf{p}^f)$. We therefore choose the Almost Ideal form of Deaton and Muellbauer (1980*b*).[8] Under these preferences the cost function describing first stage allocations becomes

$$\ln [C - a(\mathbf{p}^f)] = \ln c[b(\mathbf{p}^f), p_N] + d[b(\mathbf{p}^f), p_N]\, U$$

where

$$\ln c[b(\mathbf{p}^f), p_N] = \delta \ln b(\mathbf{p}^f) + (1 - \delta) \ln p_N + \tfrac{1}{2}\pi[\ln b(\mathbf{p}^f)^2 - 2 \ln b(\mathbf{p}^f) \ln p_N + \ln p_N^2],$$

and

$$d[b(\mathbf{p}^f), p_N] = [b(\mathbf{p}^f)/p_N]^{\mu}.$$

This leads to the first stage expenditure allocation equation

$$\frac{x - a(\mathbf{p}^f)}{y - a(\mathbf{p}^f)} = \delta + \pi \ln [b(\mathbf{p}^f)/p_N] + \mu \ln \{[y - a(\mathbf{p}^f)]/P_T\} \tag{6}$$

[8] Note that Hausman and Trimble (1984) also use Gorman Polar and Almost Ideal cost functions in their two-stage TOD electricity demand model. However, it is the first stage in their work which is assumed quasi-homothetic so the order of use is the reverse of that here.

where P_T is the total price index given by $c[b(\mathbf{p}^f), p_N]$. Substituting (6) into (5) yields

$$e_j = p_j a_j(\mathbf{p}^f) + p_j[b_j(\mathbf{p}^f)/b(\mathbf{p}^f)]\,(\delta + \pi \ln[b(\mathbf{p}^f)/p_N] + \mu \ln\{[y - a(\mathbf{p}^f)]/P_T\})\,[y - a(\mathbf{p}^f)] \qquad (7)$$

for $j = g$ and e, eliminating the need to measure either e_o or x.

To make this system operational an explicit functional form for the price aggregators $a(\cdot)$ and $b(\cdot)$ needs to be chosen. Since $a(\cdot)$ represents the level of 'necessary' expenditures on fuels (gas, electricity and other fuels) it might be argued that the Leontief form as in the standard Stone-Geary specification would be sufficient. However, as we have noted above, the term 'necessary' refers to a subsistence level of heat, light etc. which relates to fuel demands through the technology of producing these characteristics, and as a result some substitution is quite likely. We choose the following generalised Leontief form

$$a(\mathbf{p}^f) = \sum_i \sum_j \alpha_{ij} p_i^{\frac{1}{2}} p_j^{\frac{1}{2}} \quad \text{for} \quad i \quad \text{and} \quad j = e, \quad g \quad \text{and} \quad o, \qquad (8)$$

introduced by Diewert (1971) and used in demand modelling by Blundell and Ray (1984) and Blundell and Walker (1986). When $\alpha_{ij} = 0$ for $i \neq j$ the standard additive Stone-Geary specification results. The form of (8) breaks the assumption of additive separability underlying the Stone-Geary model and will permit, for example, any two of the energy goods to behave as complements. For $b(\mathbf{p}^f)$ we rely on the form employed in the Stone-Geary model[9]

$$\ln b(\mathbf{p}^f) = \sum_j \beta_j \ln p_j \quad \text{for} \quad j = e, \quad g \quad \text{and} \quad o. \qquad (9)$$

(b) An Empirical Specification

Estimation with micro data allows us to exploit variation in demographic and other characteristics across households. Indeed, it is highly unlikely that the preference parameters described above would display constancy across households. We have already argued the case for allowing the parameters of income and substitution effects to depend on durable stocks. The same argument can be made for demographic and other characteristics. These are likely to enter the expenditure allocations in a variety of ways. For example, the second stage necessary fuel expenditures (α_{ij}), the within fuel expenditure decision (β_j) and the first stage allocation (δ, π and μ) could all be affected.

Letting $\mathbf{z}_h$ represent the vector of durable, demographic and other characteristics for household 'h' we can define

$$\alpha_{ij}^h = \gamma_{ij}' \mathbf{z}_h \quad \text{and} \quad \beta_j^h = \tau_j' \mathbf{z}_h \quad \text{for each} \quad j = e, \quad g \quad \text{and} \quad o, \qquad (10)$$

where α_{ij} and τ_j represent vectors of unknown coefficients corresponding to the elements of $\mathbf{z}_h$. (There is no requirement that each α_{ij}^h and β_j^h depend on all

[9] In principle (9) can also be extended quite simply to break separability by adding in terms of the cross-product of log prices (see Blundell and Walker (1986)). The Cobb-Douglas structure for expression (9) allows a reasonably high degree of substitution which may in certain cases be excessive.

durable and household characteristics or even that they depend on the same set.) Deflating expenditures by total household income y_h we may now use (8), (9) and (10) to write our empirical specification corresponding to (7) as

$$s_{jh} = \sum_i \alpha_{ij}^h (\tilde{p}_{ih}\tilde{p}_{jh})^{\frac{1}{2}} + \beta_j^h \left\{ \delta + \pi \ln\left[b\frac{(\mathbf{p}^f)}{p_N} \right] + \mu \ln\left(\frac{[y_h - a(\mathbf{p}^f)]}{P_T} \right) \right\} \frac{[y_h - a(\mathbf{p}^f)]}{y_h} \quad \text{for } j = e \text{ and } g: \quad (11)$$

where $s_{jh} = e_{jh}/y_h$ and $\tilde{p}_{ih} = p_i/y_h$ for all i and j. Expenditure shares are chosen as the dependent variable in (11) so as to minimise the likelihood of heteroscedasticity across households. However, as we shall see, further adjustments to our stochastic specification are required.

Our approach to empirical specification is to eliminate from (11) second-order terms and then to check for the importance of such higher order interaction terms at a later stage of our specification search. In particular, we replace the term $\ln[b(\mathbf{p}^f)/p_N][y_h - a(\mathbf{p}^f)]/y_h$ by $\ln(p_E/p_N)$, where p_E is the published energy price index, the term $\ln([y_h - a(\mathbf{p}^f)]/p_T)[y_h - a(\mathbf{p}^f)]/y_h$ is replaced by $\ln(y_h/p_T)$ with P_T approximated by the retail price index and cross products of β_j^h with these terms are replaced by their cross products with $\beta_j^o = \boldsymbol{\tau}_j' \bar{\mathbf{z}}$, where $\bar{\mathbf{z}}$ is the mean vector of $\mathbf{z}_h$ across all households. These approximations enable us to rewrite (11) in the following form

$$s_{jh} = \sum_i \alpha_{ij}^h (1 - \beta_j^o \delta)(\tilde{p}_{ih}\tilde{p}_{jh})^{\frac{1}{2}} - \sum_i \sum_{k \neq j} \alpha_{ik} \beta_j^o \delta (\tilde{p}_{ih}\tilde{p}_{kh})^{\frac{1}{2}} + \beta_j^h \delta + \beta_j^o \pi \ln(p_E/p_N) + \beta_j^o \mu \ln(y_h/p_T) \quad (12)$$

for $j = e$ and g. This form allows us to assess the importance of the different price interactions and corresponds closely to the EPILOG model of Lewbel (1987).

Equation (12) is linear in transformed variables and can therefore a estimated by linear methods. However, it may be questioned as to whether all the underlying structural parameters can be identified for (12). To answer this consider the following unrestricted parameterisation of the share equation (12)

$$s_{jh} = \sum_i \theta_{ij}^h (\tilde{p}_{ih}\tilde{p}_{jh})^{\frac{1}{2}} + \phi_{1j}^h + \phi_{2j} \ln(p_E/p_N) + \phi_{3j} \ln(y_h/p_T) \quad \text{for } j = e \text{ and } g \quad (13)$$

where θ_{ij}^h are the coefficients on $(\tilde{p}_{ih}\tilde{p}_{jh})^{\frac{1}{2}}$ in (12), $\phi_{1j}^h = \beta_j^h \delta$, $\phi_{2j} = \pi\beta_j^o$ and $\phi_{3j} = \mu\beta_j^o$. The underlying parameters of this specification can be identified in the following manner. Using the estimates of ϕ_{2j} the α_{ij} coefficients can be recovered from the estimates of θ_{ij}. Having constructed $a(\mathbf{p}^f)$ from these α_{ij} parameters, an estimator for β_j^o can be derived by combining (6) with (12) (see Baker *et al.* (1987*a*)). Once the β_j^o are determined, each of the δ, μ and π parameters are identified separately for each equation and we present estimates of these underlying parameters for comparison in Section II.

As a final point when considering the influence of demographics and other characteristics in (13), it is useful to investigate the corresponding expenditure equations or Engel curves. Multiplying (13) through by y we see that each Engel curve has the following form:

$$e_j = \sum_j \theta_{ij}(p_i p_j)^{\frac{1}{2}} + \phi_{1j} y + \phi_{2j} \ln (p_E/p_N)\, y + \phi_{3j} \ln (y/P_T)\, y. \qquad (13')$$

The underlying slope depends on $\phi_{1j} + \phi_{2j} \ln (P_E/P_N)$ as well as the ϕ_{3j} parameter. In our estimation we allow demographic and other characteristics to enter through both the θ_{ij} and ϕ_{1j} terms. This allows both the intercept *and* slope of each Engel curve to vary with these characteristics. Naturally, the final form is in part determined by statistical criteria but this more economic interpretation is useful in determining the generality of any initial specification.

Allowing the θ_{ij} and ϕ_{1j} parameters to vary with demographic and other characteristics can be interpreted directly. For example, θ_{ij} measure the necessary consumption levels through the fixed cost term in the share equation (13). These are very likely to vary with the type of central heating appliance (if any) and with the season. The ϕ_{1j} parameters, on the other hand, are best interpreted as describing the marginal budget share of good j and may either reflect the impact of demographic and other characteristics on the allocation to total expenditure through δ or on the allocation of energy expenditure to particular items through β_j.

II. RESULTS

(a) *Sample and Variables*

The equations are estimated for households in the FES connected to *both* gas and electricity mains supply and interviewed in 1972–83 (we do not use households in 1972Q1 who pay for gas or electricity by account or any households in 1983Q4). There are 56,198 such households (nearly 70% of all households in the period) but we drop 5,139 to exclude outliers which might have undue influence on the results, to avoid households where the meaning of the recorded expenditure was unclear and due to problems of missing data. We are left with 51,059.[10] Means, standard deviations and brief definitions of variables used in estimation are given in Appendix A.

The dependent variables, *SHGAS* and *SHELEC* are the percentage shares of gas and electricity expenditure in household weekly net income. On average, some 3% of net income is spent on each fuel.[11] The price variables (*GPIXY*,

[10] The causes are not mutually exclusive and the following should be seen as a sequential dropping rule: zero gas or electricity expenditure (2, 108), rooms shared with other households (644), net household income per adult < £2 p.w. (1970 prices) (76), net household income per adult > £75 p.w. (1970 price) (54), share of electricity or gas expenditure in total net income > 50% (5), household contains a person unemployed < 13 weeks (1,610) and temperature data missing (642).

[11] In both cases the median is somewhat less than the mean being 2·37 in the case of gas and 2·25 for electricity. The distribution of gas shares is slightly more dispersed – the top decile (6·25) being over 8·5 times the bottom decile (0·72) compared to 5·5 times in the case of electricity where the top and bottom deciles are 5·93 and 0·99. The distribution of fuel expenditures is considered in detail in Isherwood and Hancock (1979).

EPIXY, *OPIXY*, *GEPIXY* and *FPIXP*) are all calculated using published indices from the Retail Price Index.[12] We proxy the price of other fuels with the price of coal, this being the most important fuel other than gas and electricity. Prices are allowed to change quarterly, and are averages of published monthly indices (the value attached to each household is that in the quarter of interview for those paying by slot meter and the quarter prior to interview for those paying by bill). Note that for the most part, block rate pricing which has been the focus of much attention in the United States literature on electricity demand does not exist in the United Kingdom. We do not allow for any regional variation in fuel prices, although this certainly does exist (regional dummies are included).

The variables relating to net income and to household characteristics are reasonably self explanatory. Note that *INCOME* may partly proxy ownership of those durables we do not observe, durable quality, and insulation. Variables indicating the presence of children under 5 (school-age) and adults not in the labour force (*KIDSD*, *HADULT*), are intended to proxy time spent in the house and the age dummies (*AGEH*-40, *AGEH*-65) to pick up differences in preferences for fuel use. We would not expect the type of tenure to be as important in determining expenditure conditional on durables, as it would be in determining the durable stock itself. Nevertheless housing dummies (*COUNCIL*, *RENT*, *OWNCOMP* and *RFREE*) are included in the equations since, like income, they may proxy unobservables. Seasonal effects are modelled in part with dummies (*SPRAUT*, *SUMMER*) and we also include a measure of the average outside air temperature in the household's region in the relevant quarter (*TEMP*). To the extent that regional price differentials are stable the regional dummies will pick up differences in cost. They may also proxy variations in the quality of the housing stock.

(*b*) *Estimation Results*

The parameter estimates corresponding to equations (13) are presented in Table 1 *a* and 1 *b*. In selecting the models reported we paid particular attention to seasonal variation, allowing certain parameters to vary across the season. We found it acceptable to group the Spring and Autumn observations resulting in the three columns in both 1 *a* and 1 *b*. For coefficients on some variables there appeared to be little seasonal impact at all and for these a single parameter estimate, restricted to be constant across seasons, appears in the first column. For others, in particular the price, central heating and trend variables, seasonal

[12] These variables measure the national average price of a unit of each fuel and not the marginal price which in the case of gas and electricity will differ due to the fixed cost to the consumer of the standing charge. While it is true that theory indicates the marginal measure as being the correct one, the use of average prices could be justified on the grounds that consumers may often be more fully informed of these. We should stress that with the exception of date of interview we use *no* household specific information in the construction of the price variables, which are simply national price indices for the period of consumption. Note that within the spirit of the TOD electricity studies in the United States we could assume that households make a third stage allocation of electricity expenditure into different periods of the day (in practice, peak and off-peak). This would provide some justification for our use of an electricity price index at the second stage, to model total electricity consumption.

Table 1

*Parameter estimates**

	(a) Gas		
	Winter	Spring/Autumn	Summer
Intercept	−1·054 (0·136)	−0·752 (0·107)	−0·422 (0·139)
GPIXY	−8·311 (2·132)	−2·667 (0·985)	0·256 (1·346)
GPIXY × *GCH*	0·463 (0·025)		
EPIXY	−7·347 (1·836)	−2·679 (0·846)	−0·052 (1·116)
EPIXY × *ECH*	−0·076 (0·019)		
CPIXY	0·985 (0·270)	0·550 (0·152)	−0·112 (0·170)
GEPIXY	15·219 (3·731)	5·223 (1·717)	0·188 (2·338)
FPIXP (log)	3·944 (0·542)	1·562 (0·362)	0·362 (0·475)
INCOME (log)	−0·822 (0·086)		
HSIZE (log)	0·598 (0·027)		
KIDSD	0·142 (0·028)		
HADULT	0·164 (0·025)		
AGEH-40	0·125 (0·022)		
AGEH-65	−0·168 (0·038)		
ROOMS	0·160 (0·010)		
GCH	0·811 (0·074)	0·177 (0·068)	−0·395 (0·076)
ECH	−0·764 (0·088)	−0·411 (0·076)	−0·168 (0·092)
OCH	−1·706 (0·075)	−1·096 (0·039)	−0·694 (0·057)
TEMP	−0·084 (0·006)		
WASH	0·114 (0·029)		
FRIDGE	0·347 (0·045)		
CONCOAL	−1·522 (0·129)	−0·979 (0·073)	−0·479 (0·082)
COUNCIL	−0·236 (0·024)		
RENT	−0·117 (0·039)		
RFREE	0·106 (0·110)		
OWNCOMP	−0·046 (0·030)		
NORTH	0·175 (0·027)		
EANG	0·119 (0·066)		
LONDON	0·233 (0·034)		
SEAST	0·192 (0·031)		
WALSW	0·089 (0·038)		
SCOT	0·308 (0·047)		
TREND	−0·027 (0·006)	−0·014 (0·003)	−0·003 (0·005)

$R^2 = 0·412$.
$F = 662·9$.
* Heteroscedasticity adjusted standard errors in parentheses.

differences in response were notable. These additional seasonal effects occur despite the introduction of our temperature variable and over and above standard intercept dummies.[13]

To assess the overall specification of our equations we conducted a number of statistical tests designed to pick up functional form mispecification and heteroscedasticity in the error variance. Given the level of the heteroscedasticity

[13] The reader may be puzzled at the relative magnitude of the signs of the seasonal intercepts in the gas equation (the differences between these in the electricity equation are quite insignificant). The conditioning on temperature should be stressed. If *TEMP* is removed from the model then the pattern is the reverse of that in Table 1.

Table 1 (*continued*)*

	(*b*) Electricity		
	Winter	Spring/Autumn	Summer
Intercept	−1·254 (0·117)	−1·270 (0·104)	−1·212 (0·144)
GPIXY	−1·989 (1.531)	−0·212 (0·972)	1·454 (1·491)
GPIXY × *GCH*	0·060 (1·019)		
EPIXY	−1·595 (1·351)	−0·201 (0·832)	−1·353 (1·256)
EPIXY × *ECH*	0·408 (0·037)		
CPIXY	0·374 (0·212)	0·191 (0·148)	−0·009 (0·241)
GEPIXY	3·586 (2·715)	0·545 (1·691)	−2·523 (2·573)
FPIXP (log)	1·333 (0·474)	1·054 (0·358)	0·804 (0·577)
INCOME (log)	−1·104 (0·077)		
HSIZE (log)	0·743 (0·028)		
KIDSD	0·103 (0·029)		
HADULT	0·010 (0·024)		
AGEH-40	−0·061 (0·022)		
AGEH-65	−0·358 (0·036)		
ROOMS	0·130 (0·010)		
GCH	−0·900 (0·061)	−0·636 (0·052)	−0·549 (0·062)
ECH	1·233 (0·174)	0·207 (0·142)	−0·847 (0·174)
OCH	−0·829 (0·077)	−0·571 (0·042)	−0·330 (0·067)
TEMP	−0·053 (0·006)		
WASH	0·160 (0·029)		
FRIDGE	0·748 (0·045)		
CONCOAL	−1·102 (0·101)	−0·896 (0·054)	−0·761 (0·093)
COUNCIL	−0·039 (0·025)		
RENT	−0·106 (0·038)		
RFREE	0·150 (0·116)		
OWNCOMP	0·125 (0·028)		
NORTH	−0·049 (0·026)		
EANG	0·180 (0·059)		
LONDON	0·393 (0·036)		
SEAST	0·272 (0·030)		
WALSW	0·315 (0·039)		
SCOT	0·284 (0·045)		
TREND	0·001 (0·005)	0·003 (0·003)	0·006 (0·006)

$R^2 = 0·339$.
$F = 483·9$.
* Notes as in Table 1 (*a*).

indicated by these tests, the standard errors in Tables 1 (*a*) and 1 (*b*) are adjusted for heteroscedasticity using the White (1980) method described in Messer and White (1984). The tests and results are reported in detail in Baker *et al.* (1987*c*) and suggest some remaining mispecification, although with such a large sample size detecting mispecification of this type is almost inevitable. As a final check of the specification we undertook tests against alternative models. In comparison to a more general model, the chosen specification appears acceptable especially for electricity, whilst a simple linear model was found to be insufficiently flexible to capture the wide variation in observed behaviour across our sample.

Turning to the estimated parameters, the first six parameters after the

intercept presented in the tables represent the various own price and cross-price terms. The first of these in Table 1 *a* refers to the coefficient on the $\tilde{p}_g$ (*GPIXY*) variable and the second captures the interaction between price and gas central heating ownership. These price interactions indicate a significant own price effect that varies with season and ownership. For electricity expenditures in Table 1 *b* the significance of the ownership effect on own price (*EPIXY*) is replicated although the seasonal impact is less strong. Given the dominance of gas expenditures for water and space heating purposes these differences in seasonal effects are to be expected. In terms of the economic model of the previous section, they suggest a significant change in fixed costs associated with these variables. Together with the next four terms which assess the importance of the other price variables $\tilde{p}_e, \tilde{p}_o$ and $(\tilde{p}_g\tilde{p}_e)^{\frac{1}{2}}$ these price coefficients represent the within fuel substitution possibilities. The within fuel cross-price terms $(\tilde{p}_o\tilde{p}_g)^{\frac{1}{2}}$ and $(\tilde{p}_o\tilde{p}_e)^{\frac{1}{2}}$ were found to be insignificant. However, the significance of the $(\tilde{p}_g\tilde{p}_e)^{\frac{1}{2}}$ term is enough to reject the additive Stone-Geary model for within fuel substitution. The final price coefficient is that of the log of the fuel to non-fuel price (*FPIXP*) and indicates the importance of fuel/non-fuel substitution.

It should be noted that many parameters that would also have to be estimated from time series variation alone in aggregate studies, income and ownership coefficients for example, exploit the extra cross-section information here. Since these variables are likely to be correlated over time with prices, pooled micro-data models can be seen to increase the precision of estimated price effects. Moreover, the importance of price interactions with ownership variables noted above suggests that aggregate studies could easily mispecify the price terms when ownership patterns change systematically over time. The price and income elasticities that correspond to our estimates are described below and further investigation showed that the significance of the within fuel price terms does not appear to be an artifact of their being scaled by household income.

Tables 1 (*a*) and (*b*) show that many other characteristics are important. A doubling in household size (*HSIZE*) leads to both shares rising by about one half percentage point. Since the dependent variable represents the percentage share of gas or electricity expenditure out of income a coefficient on a dummy like *KIDSD* has an easy interpretation; the presence of a young child increases the percentage share on gas and electricity expenditure by 0·142 and 0·103 respectively while a non-working adult significantly influences only the gas expenditure share. The coefficients of *AGE*-40 and *AGE*-65, must be summed to find the full effect of the head being over 65 relative to households where the head is aged less than 40. The change in demand with age differs quite considerably between the two fuels. With gas it first rises and then falls, whereas with electricity there is only a significant change (which is substantial) when the head is over 65. Note that these effects condition on appliance ownership and income. We might have expected a positive effect coming from an increasing preference for heat with age but this does not seem to exist. The size of the house, measured in terms of the *ROOMS* variable, has a very well determined small positive effect which is quite similar for both fuels.

We have already noted the effect of central heating on own-price responses. In addition, gas central heating adds 0·811 to the percentage of gas expenditures out of income in the winter. Predictably, this falls in warmer seasons but surprisingly is negative in the summer. The effects of electric central heating on electricity shares are even larger, again being negative in the summer. Similarly, ownership of electricity or other central heating significantly reduces the gas share and mirror image effect is to be found on the electricity share. The effect of washing machine and fridge ownership is positive and significant for both electricity and gas, possibly reflecting a higher permanent income or preference towards energy consumption amongst such households.

The conditioning on durable ownership should again be stressed when considering the region and tenure dummies; these variables are not proxies for presence or type of central heating for example. The lack of big tenure effects is striking. Council tenants have significantly lower gas shares than the base category of mortgaged owner occupiers and this may be a result of households in this tenure type having a lower level of unobserved gas-powered appliances. There appears to be no discernible evidence that this tenure type proxies lack of insulation or any other differences in thermal qualities of housing stocks. Other things being equal, including *TEMP* which varies with region as well as time, gas shares are significantly higher in the North, the South East, London and Scotland compared to a base of the Midlands. The same is true of electricity shares in all but the North. Broadly speaking, London and Scotland stand out as the higher expenditure regions, followed by the South East.

(*c*) *Model Properties*

Since income enters via the within-fuel price terms we cannot look at the coefficient of log income alone to assess the effect of household income on the expenditure shares. As with the price terms, a derived measure is required to give meaning to the estimated parameters. This is provided by the income and price elasticities, the formulae for which are given in Appendix B. A change in the price of any fuel, say gas, affects the demand for any fuel in two ways. First, there is a direct effect picked up by the gas price and gas-electricity price interaction term in our estimated equations. Second, the change in gas price leads to a change in the relative price of fuel to non-fuel, which also enters our model. (Within the context of the theoretical model from the previous section, there is both a second stage re-allocation and one at the first stage given that the price index for all fuels changes.) The formulae for the price elasticities in equations (B 2)–(B 4) of Appendix B take account of *both* these effects. To allow for the effect of a change in the price of any fuel on the overall fuel price we assume the two are related by

$$\ln p_E = \sum_i w_i \ln p_i \quad \text{where} \quad i = e, g, o \tag{14}$$

and where the w_i are the published RPI weights for each fuel as a proportion of that for all fuels (w_F in (B 5) is the published weight for all fuels in proportionate terms). These weights change annually.

Table 2

*Elasticities disaggregated by demographic characteristics**

	Gas			Electricity		
	income η_{gy}	own price η_{gg}	electricity price η_{ge}	income η_{ey}	own price η_{ee}	gas price η_{eg}
All	0·115	−0·311	−0·373	0·131	−0·758	0·185
	(0·119)	(−0·249)	(−0·253)	(0·130)	(−0·815)	(0·223)
GasCH	0·152	−0·238	−0·303	0·027	−0·776	0·267
	(0·151)	(−0·221)	(−0·248)	(0·025)	(−0·815)	(0·291)
ElecCH	−0·085	−0·117	−0·812	0·186	−0·540	0·093
	(−0·084)	(−0·046)	(−0·539)	(0·191)	(−0·581)	(0·117)
Age-65	0·078	−0·289	−0·554	0·084	−0·739	0·176
	(0·088)	(−0·164)	(−0·479)	(0·086)	(−0·826)	(0·226)
Kids	0·211	−0·394	−0·246	0·263	−0·797	0·166
	(0·218)	(−0·336)	(−0·210)	(0·253)	(−0·845)	(0·191)
Home own.	0·150	−0·324	−0·323	0·130	−0·762	0·195
	(0·154)	(−0·268)	(−0·232)	(0·123)	(−0·814)	(0·233)
Top decile	0·012	−0·208	−0·170	−0·172	−0·684	0·290
of income	(−0·015)	(−0·184)	(−0·114)	(−0·208)	(−0·717)	(0·315)
Middle decile	0·137	−0·336	−0·290	0·167	−0·764	0·182
of income	(0·139)	(−0·287)	(−0·248)	(0·171)	(−0·825)	(0·207)
Lower decile	0·139	−0·444	−0·440	0·177	−0·759	0·137
of income	(0·149)	(−0·258)	(−0·400)	(0·187)	(−0·847)	(0·196)

* Mean values with median values in parentheses.
Note: Deciles of income calculated on the basis of income per adult capita.

Table 2 presents the effects of some of the household characteristics on the income and price elasticities. For each sub-group of households the elasticities are evaluated first at the corresponding group means of the data and second for each household in the group with the median elasticity being selected for presentation.[14] The first line in the table gives the elasticities prior to any disaggregation. These show that, conditional on durable ownership, both gas and electricity are necessities, as one would expect, and price inelastic (especially gas). Not shown is the fact that the income elasticities are negative for both fuels, indicating inferiority, for about one-third of all households. This demonstrates the importance of using micro-data to get the full picture of household behaviour. Some negative values for gas consumption are explained by the ownership of electric central heating. For households with such central heating, increases in income are distributed more towards electricity consumption as can be inferred from the larger than average income elasticity for electricity shown in the right-hand side of the Table. The top deciles of the income distribution have the lowest income elasticity, something true of both

[14] When calculating the distribution of elasticities we use the estimated share for each household s_{jh}, as predicted by our equations, rather than the actual share. This removes the residuals from the calculations, something we see as important given that our equations explain little more than two-fifths of the variation in the observed shares. Of course this has no effect on the elasticities evaluated at total sample means.

gas and electricity. Households experiencing higher income may well increase consumption of fuels through the buying of new appliances, etc. However, conditional on durable stocks we may not expect rich households, already consuming well above necessary consumption levels, to increase consumption further. It may be the case that higher income proxies durable quality, insulation and time spent out of the house, none of which we observe and all of which will be associated with lower energy demand.

The price elasticity results for gas indicate the most elastic effects for households with young children and with lower than average income. Note that for both types of fuel the own price elasticities are smaller for those households with 'own-fuel' central heating reflecting the fact that these households are locked-in to own fuel consumption. The larger own price elasticity for electricity is reflected in the positive cross price elasticity of the gas price on electricity consumption. A relative increase in the price of electricity to gas would be followed by a significant switch away from electricity consumption. For gas consumption, price and income elasticities are generally smaller, the cross price elasticity displaying some gross complementarity of gas with electricity consumption.

Finally we derive some of the underlying structural parameters that were described in the theoretical section of this paper and which are necessary for welfare measurement. For example, consider the underlying values of the δ, π and μ parameters in equation (12). These are over-identified in the sense that the gas and electricity equations provide us with two estimates of each. We could impose the cross-equation restrictions on these parameters but here we simply consider the closeness of the unrestricted parameter estimates. This will indicate the overall reliability of the restrictions. For the gas equation the β_j^o parameter has the value 0·347 while δ is given by 0·022, π by 0·056 and μ by −0·023. For the electricity equation the β_j^o parameter is 0·272 and the corresponding estimate of δ is 0·039, for π the estimate is 0·040 and for μ the estimate is −0·041. These are all reasonably close and intuitive given the completely unrestricted estimation procedure, providing some indication of the appropriateness of our model specification. The small but negative values for μ for example, suggest that supernumerary energy expenditure is a slight necessity.

III. SUMMARY AND CONCLUSIONS

In this paper we have considered the demand by individual households in Great Britain for gas and electricity – the two principal fuels in the domestic sector. We have developed a theoretical model using a two-stage budgeting framework of the allocation of household expenditures conditional on durable ownership, and have estimated share equations which represent linear approximations to those suggested by the theoretical model. Estimation took place using over 50,000 households, pooled from 12 consecutive years of the *Family Expenditure Survey*, the first time to our knowledge that data of this kind have been used on this scale to model household energy demand in the United Kingdom.

We have emphasised the variation in the estimated elasticities across the households in our samples. For example, conditioning on such characteristics as number of rooms and household size as well as durable ownership, the income elasticities of both fuels at the means of the data were small and positive, suggesting that demand rises with income, although with strong variations across household types. Indeed, for part of the sample the income elasticities for each fuel were negative. Price elasticities were generally larger, especially for electricity consumption, and also displayed considerable variation across the sample. This was not only a reflection of the wide variation in consumption levels but also the very different reactions displayed by households in different seasons and with different central heating ownership. Interaction terms of such household characteristics with prices were found to be significant and have important bearing on the forecasting of electricity and gas consumption as well as the nature of the aggregate relationship between consumption and price. With changing patterns of ownership, our results suggest that this relationship would not be stable over time or across seasons. This point is also true for income effects. Moreover, since the survey information is being used to estimate parameters associated with income, ownership and other variables that differ across households, price effects can be expected to be estimated more precisely from a data set of this type even if no allowance is made for cross-section variation in prices. Our results show the value of using household survey data pooled over a reasonable length of time.

Finally, we can turn to the implications of these results for welfare measurement. The important inter-relationships between characteristics, prices and incomes displayed throughout this study have shown the usefulness of working at the micro rather than aggregate level and this carries over to welfare measurement. The welfare cost of subsidising or taxing fuel prices will differ substantially across households with differing income and other characteristics. However, having emphasised the close relationship between the parameters of our empirical model and its theoretical counterpart, our empirical results enable the construction of constant utility costs and compensating variations on an individual household basis. This in turn will provide the basis for an analysis of the trade-off between efficiency and equity resulting from changes in relative or overall fuel prices.

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Appendix A: Data

SHGAS, SHELEC The numerators of these variables include all expenditures on gas and electricity e.g. including standing charges. However, payments for equipment rental or servicing are excluded. The recorded expenditures refer to a quarterly period if payment is by bill and a fortnight if payment is by slot meter. All amounts, however, are expressed in weekly terms, as is income. The weekly value of the

Table A1: Descriptive statistics and definitions of variables

$n = 51{,}059$

Variable	Mean	S.D.	Definition
SHGAS	3·09	2·77	Gas expenditure/net income × 100
SHELEC	2·93	2·51	Electricity expenditure/net income × 100
GPIXY	3·21	2·20	Gas price (January 1974 = 100)/income
EPIXY	4·30	2·87	Electricity price (January 1974 = 100)/income
OPIXY	3·91	2·61	Coal price (January 1974 = 100)/income
GEPIXY	3·70	2·47	(*GPIXY* × *EPIXY*)
*FPIXP**	1·18	0·13	Price of all fuels/price of non-fuels (January 1974 = 1·00)
*INCOME**	0·98	23·54	Net weekly household income/[Retail Price Index (January 1974 = 100)]
*HSIZE**	2·78	1·44	Number of persons in the household
KIDSD	0·17	0·37	= 1 if child aged <5 present
HADULT	0·42	0·49	= 1 if any adults in household out of the labour force
AGE-40	0·65	0·48	= 1 if head of household aged >40
AGE-65	0·26	0·44	= 1 if head of household aged >65
ROOMS	5·15	1·24	Number of rooms in households' accommodation
GCH	0·42	0·49	= 1 if household has gas central heating
ECH	0·06	0·23	= 1 if household has electric central heating
OCH	0·05	0·21	= 1 if household has other central heating
WASH	0·76	0·42	= 1 if household has washing machine
FRIDGE	0·90	0·30	= 1 if household has fridge/freezer
CONCOAL	0·02	0·13	= 1 if household receives concessionary coal from current/former employer
COUNCIL	0·33	0·47	= 1 if accommodation is rented from LA
RENT	0·10	0·30	= 1 if accommodation is rented privately
RFREE	0·01	0·11	= 1 if accommodation is rent free
OWNCOMP	0·21	0·40	= 1 if accommodation is owned outright
TEMP	9·72	4·15	average outside temperature in the region and quarter of expenditure (°C)
SPRAUT	0·50	0·50	= 1 if expenditure in April–June or October–December
SUMMER	0·22	0·42	= 1 if expenditure in July–September
NORTH	0·31	0·46	= 1 if resident in North
EANG	0·30	0·16	= 1 if resident in East Anglia
LONDON	0·15	0·35	= 1 if resident in London
SEAST	0·19	0·39	= 1 if resident in South East
WALSW	0·09	0·29	= 1 if resident in Wales/South West
SCOT	0·07	0·25	= 1 if resident in Scotland
TREND	24·64	13·50	quarterly trend (1971 Q1 = 1)

* The natural logarithms of these variables are used in estimation. There are very slight differences between gas and electricity equations in the means and standard deviations of some variables because a household may pay for one fuel by account and another by slot meter, thus being assigned to a different quarter in each case. The values shown are those for gas.

last slot meter rebate is subtracted – variables are thus net of such rebates. Where payment is by budget account, the value shown on the last advice is taken – see Footnote 6.

GPIXY, EPIXY, OPIXY, GPIXY — Price variables constructed using series published in the *Digest of UK Energy Statistics*. Quarterly averages of the published monthly figures were taken.

FPIXP — Numerator is published in RPI for fuel. Demoninator calculated as follows, assume: In RPI = $(1 - w_F)$ ln (Non-Fuel Index) + w_F ln)

Fuel Index). RPI, Fuel Index and w_F all published data, where w_F = the weight of fuels in RPI. Non-Fuel Index therefore deduced easily.

TEMP An estimate of the outside air temperature (°C) in the households region and quarter of interview. Taken as average of monthly figures in a representative town in each region.

Source: *Whitaker's Almanack.*

Appendix B: Elasticity formulae

Income elasticity

$$\eta_{jy} = \{[\phi_{3j} - \sum \theta_{ij}(\tilde{p}_{ih}\tilde{p}_{jh})^{\frac{1}{2}}]/s_{sj}\} + 1 \tag{B 1}$$

Own price elasticities

$$\eta_{jj} = \{[\theta_{jt}\tilde{p}_{jh} + \tfrac{1}{2}\theta_{eg}(\tilde{p}_{eh}\tilde{p}_{gh})^{\frac{1}{2}} + \phi_{2j}w_j]/s_{jh}\} - 1 \tag{B 2}$$

Cross price elasticities w.r.t. gas and electricity

$$\eta_{ji} = [\theta_{ij}\tilde{p}_{ih} + \tfrac{1}{2}\theta_{eg}(\tilde{p}_{eh}\tilde{p}_{gh})^{\frac{1}{2}} + \phi_{2i}w_i]/s_{jh} \quad \text{for} \quad i \quad \text{and} \quad j = e, g \tag{B 3}$$

Cross price elasticities w.r.t. other fuels

$$\eta_{ji} = (\theta_{ij}\tilde{p}_{ih} + \phi_{2i}w_i)/s_{jh} \quad \text{for} \quad i = o \quad \text{and} \quad j = e, g \tag{B 4}$$

Cross price elasticities w.r.t. non-energy goods

$$\eta_{jN} = -[\phi_{2j} + \phi_{ej}(1 - w_F)]/s_{jh} \quad \text{for} \quad j = e, g \tag{B 5}$$

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Quantifying Customer Response to Dynamic Pricing

California's Statewide Pricing Pilot experiment showed that residential and small to medium commercial and industrial customers conclusively reduced peak-period energy use in response to time-varying prices. Responsiveness varied with rate type, climate zone, season, air conditioning ownership, and other customer characteristics.

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California experienced a major power crisis in its unregulated wholesale markets during 2000 and 2001. While many problems conspired to create the crisis, most people agree that it was exacerbated by the lack of dynamic price signals in retail markets. Dynamic pricing would have given customers an incentive to lower loads during peak times which, in turn, would have reduced market-clearing prices and partially mitigated market power. However, dynamic pricing requires the installation of digital interval meters and makes economic sense only if its benefits exceed the costs of the new metering infrastructure. The benefits depend on the impact of dynamic pricing on customer loads and on avoided supply-side costs, both of which are uncertain.

To help address the uncertainty regarding customer load impacts, California's three investor-owned utilities,[1] in concert with the two regulatory commissions, conducted an experiment to test the impact of time-of-use (TOU) and dynamic pricing among residential and small commercial and industrial (C&I) customers. Known as the Statewide Pricing Pilot (SPP), the experiment's pri-

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mary objective was to estimate the average impact of time-varying rates on energy use by rate period and to develop models that could be used to predict impacts under alternative pricing plans. The broader policy objective underlying the SPP was to provide information that would allow each of the three utilities to determine whether the demand–response benefits from reductions in energy use and coincident peak demand from dynamic pricing were sufficiently large to offset the net metering, billing, and other infrastructure costs required to implement rate reform.[2]

This article provides a summary of the design and results associated with the SPP. In brief, the experiment showed that residential and small to medium C&I customers can and did conclusively reduce peak-period energy use in response to time-varying prices. Responsiveness varied with rate type, climate zone, season, air conditioning ownership, and other customer characteristics.

I. SPP Design and Methodology[3]

The SPP involved roughly 2,500 customers and ran from July 2003 to December 2004. Several different rate structures were tested. These included a traditional TOU rate, where price during the peak period was roughly 70 percent higher than the standard rate and about twice the value of the price during the off-peak period. The SPP also tested two varieties of critical peak pricing (CPP), where the peak period price during a small number of critical days was roughly five times higher than the standard rate and about six times higher than the off-peak price.[4] One CPP rate, CPP-F, had a fixed critical peak period and day-ahead notification. The other, CPP-V, had a variable-length peak period on critical days and day-of notification. CPP-V customers had the option of having an enabling technology, such as a smart thermostat, installed free of charge to help facilitate demand response.

The experiment showed that residential and small to medium C&I customers can and did conclusively reduce peak-period energy use in response to time-varying prices.

The SPP experimental design included control groups that stayed on the standard tariff and treatment groups that were placed on the new rates. Treatment customers were divided into subgroups that faced different price levels so that statistical relationships between energy use by rate period and prices could be estimated. These statistical relationships, referred to as demand models in the economics literature, were used to estimate demand response impacts for the average prices used in the SPP. Importantly, they can also be used to estimate the impact of other prices that are within a reasonable range of those tested. Most of the demand models also allow the analyst to adjust the magnitude of price responsiveness to account for variation in climate and the saturation of central air conditioning. Thus, demand response impact estimates can be developed for customer segments with characteristics that differ from those included in the experiment.

The demand system estimated for each tariff consisted of two equations. One equation predicts daily energy use as a function of daily price and other factors. The second equation predicts the share of daily energy use by rate period. This type of demand system is commonly used in empirical analysis of energy consumption.

II. Residential Customer Response

Three rate treatments were examined for residential customers: CPP-F, CPP-V and TOU. The CPP-F and TOU rates were implemented among a statewide sample of customers. The sample size for the CPP-F treatment was much larger than for the TOU treatment and the results are more robust. The CPP-V rate was implemented only in the SDG&E service territory.

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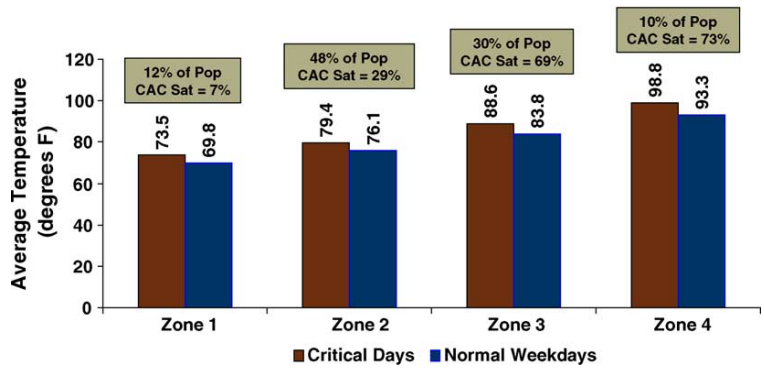

Figure 1: Population, Air Conditioning Saturations and Average Temperature by Climate Zone

A. CPP-F impacts

A key focus of the SPP was to assess the impact of dynamic tariffs. Estimated impacts varied by day type: critical days (when the highest prices are in effect); normal weekdays (when lower peak prices are in effect); and weekends (which have the same prices as off-peak weekday periods). They also varied across California's diverse climate zones, where, as seen in **Figure 1**, average temperatures and central air conditioning (CAC) saturations differ significantly.

Figure 2 summarizes the impact of the average CPP-F prices on energy use during the peak period on critical and normal weekdays. Statewide, the estimated average reduction in peak-period energy use on critical days was 13.1 percent.[5] Impacts varied across climate zones, from a low of −7.6 percent in the relatively cool climate of zone 1 (which includes San Francisco) to a high of −15.8 percent in the hot climate of zone 4 (which includes Palm Springs and the Central Valley city of Bakersfield). The average impact on normal weekdays was −4.7 percent, with a range across climate zones from −2.2 percent to −6.5 percent.

Other key findings for the CPP-F rate include:

- Differences in peak-period reductions on critical days across the two summers, 2003 and 2004, were not statistically significant.
- Differences in impacts across critical days when two or three critical days are called in a row (as might occur during a heat wave) were not statistically significant.
- Average peak-period impacts on critical days were greater during the hot summer months of July through September (−14.4 percent) than during the milder summer months of May, June, and October (−8.1 percent).
- Peak-period reductions on normal weekdays were lower in the winter (−3.9 percent) than in the summer (−4.7 percent), and lower during the milder winter months of November, March, and April (−0.7 percent) than during the colder winter months of December, January, and February (−4.7 percent).
- There was essentially no change in total energy use across the entire year based on average SPP prices. That is, the reduction in energy use during high-price periods was almost exactly offset by increases in energy use during off-peak periods.

Understanding how price responsiveness varies with differences in selected customer characteristics can be useful from both a policy and marketing perspective. For example, if high users are more responsive than low users, different tariffs might be targeted at each customer segment in order to maximize demand response and/or minimize implementation costs. If spa owners are more responsive than households that do not have spas, it may be possible to improve overall demand response from a

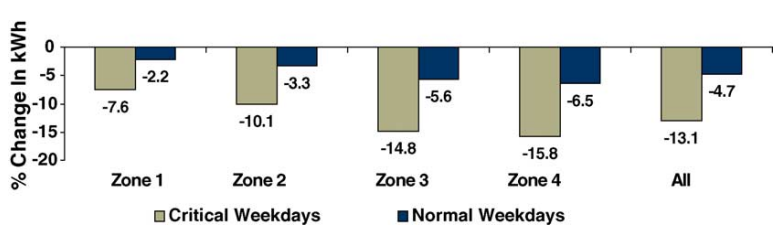

Figure 2: Percent Change in Residential Summer Peak-Period Energy Use (Avg. CPP-F Prices/Avg. 2003/2004 Weather)

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Table 1: Percent Impact on Energy Use by Rate Period on Critical Days Given a Change in Customer Characteristics

Variable	Customer Characteristic	Peak Period	Off-Peak Period	Daily Period
None	Average	−13.06	2.04	−2.37
Central A/C	Yes	−17.43	3.21	−2.82
	No	−8.05	0.68	−1.87
Average daily use	200 percent of average	−14.70	1.77	−3.04
	50 percent of average	−12.15	2.21	−1.99
Spa	Yes	−15.84	3.53	−2.13
	No	−12.94	1.93	−2.41
Electric cooking	Yes	−11.53	0.32	−3.14
	No	−14.09	3.16	−1.87
Persons per household	Four	−12.13	1.51	−2.47
	Two	−13.99	2.46	−2.35
Annual income	$100,000	−16.15	2.99	−2.60
	$40,000	−10.92	1.68	−2.00
Housing type	Single family	−13.98	2.72	−2.16
	Multi-family	−11.78	0.43	−3.14
# Bedrooms	Four	−15.67	2.12	−3.07
	Two	−11.59	2.01	−1.96
College education	Graduate	−18.52	3.69	−2.79
	Did not graduate	−8.56	0.93	−1.84

voluntary program by targeting spa owners.

Table 1 shows how average customer impacts by rate period on critical days varied with differences in selected customer characteristics. As seen, air conditioning ownership had a very significant influence on demand response, with critical day, peak-period reductions being more than twice as large for households with air conditioning than for those without. Whether or not the head of the household has a college education has a similar influence to that of air conditioning ownership. Households where the head has a college education were roughly twice as responsive as households where the head did not have a college education. Income is also an influential characteristic, with higher-income households being more responsive. Obviously, college education and income are highly correlated. Average daily energy use, spa ownership and number of bedrooms were all positively correlated with responsiveness, while persons per household and electric cooking were negatively correlated with demand response. Single-family households were more price responsive than multiple-family households.

As previously mentioned, demand models are versatile policy tools that can be used not only to estimate the impact of the specific rates that were tested in the pilot but also to predict the impact of rates not included in the pilot. As indicated above, demand models can also predict how impacts vary with customer characteristics.

Figures 3 and 4 show how the percent reduction in peak-period energy use on critical days varied with changes in the peak-period price (when everything else is held constant). The curves indicate that the reduction in peak-period energy use increases as prices increase, but at a diminishing rate. Figure 3 shows that reductions are greater in percentage terms in hotter climate zones, where air conditioning saturations are high, than in cooler zones. It should be noted that the difference in the absolute value of the peak-period reduction would be even greater than the difference in the percentage reduction as average use prior to the demand change is much larger in hotter climate zones than in cooler ones. Figure 4 shows that peak-period reductions are greater in the inner summer months of July, August, and September than in the outer summer months of May, June, and October. We believe the greater responsiveness in the inner summer is due primarily to the influence of central air conditioning.

The impacts shown in Figures 3 and 4 are driven more by the relationship between the initial average price and price in each rate period under the alternative rate more than they

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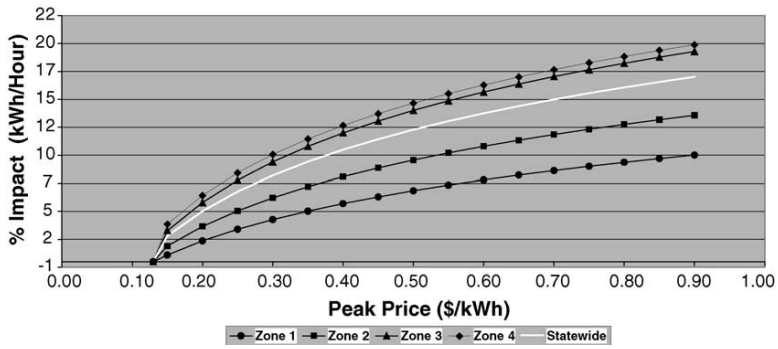

Figure 3: Percent Reduction in Peak-Period Energy Use on Critical Days, Average Summer, 2003/2004

are by the absolute levels of prices. In the SPP, the average price for customers on the standard rate was roughly 13 ¢/kWh, the average peak-period price on critical days was roughly 59 ¢/kWh and the average off-peak price was 9 ¢/kWh. If, instead, the average standard price were, say, 7 ¢/kWh, a critical peak price of roughly 32 ¢/kWh combined with an off-peak price of around 5 ¢/kWh would produce approximately the same impact as that found in the SPP. Thus, the SPP demand models can be used to predict the impact of dynamic pricing in other regions of North America and possibly in other developed economies, once adjustments are made for climatic conditions and customer characteristics.

B. TOU impacts

As previously mentioned, in addition to the CPP-F tariff, the SPP also examined traditional TOU rates. The reduction in peak-period energy use resulting from a TOU rate in the inner summer of 2003 equaled −5.9 percent. This 2003 value is comparable to the estimate for the CPP-F tariff on normal weekdays when prices were similar to those for the TOU treatment. However, in 2004, the TOU rate impact (−0.6 percent) almost completely disappeared.

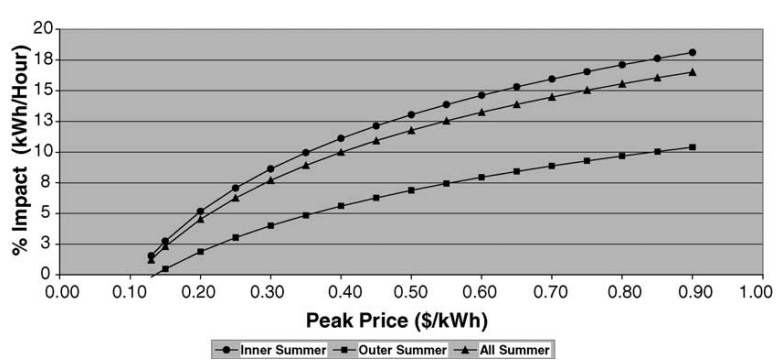

Figure 4: Percent Reduction in Peak-Period Energy Use on Critical Days, Inner Summer, Outer Summer, Average Summer

TOU winter impacts were comparable to the normal weekday winter impacts for the CPP-F rate.

Drawing firm conclusions about the impact of TOU rates from the SPP is somewhat complicated by the fact that the TOU sample sizes were small relative to the CPP-F sample sizes.[6] Small sample sizes are more easily influenced by outliers and changes in the sample composition over time than are larger samples. Further complicating the estimation of the daily energy equation (one of the two equations underlying the impact estimates) is that variation in daily prices over time was quite small for the TOU rate, making it difficult to obtain precise estimates of daily price responsiveness.[7] In short, we don't have as much confidence in the TOU results as we do the CPP-F results. Indeed, an argument could be made that the normal weekday elasticities from the CPP-F treatment may be better predictors of the influence of TOU rates on energy demand than are the TOU price elasticity estimates. On the other hand, if the TOU results are accurate, they have very important policy implications, since they indicate that the relatively modest TOU prices tested in this experiment do not have sustainable impacts across the two summers.

C. CPP-V impacts

The residential CPP-V rate was tested between two different

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populations, both within the SDG&E service territory.

Track A customers were drawn from a population of customers with average summer energy use exceeding 600 kWh per month. The saturation of central air conditioning among the Track A treatment group was roughly 80 percent, much higher than among the general population, and average income was also much higher. Track A customers were given a choice of having an enabling technology installed free of charge to facilitate demand response. About two-thirds of the participants took one of three technology options[8] and about half of those selected a smart thermostat.

Track C customers were recruited from a sample of customers that had previously volunteered for a Smart Thermostat pilot.[9] All Track C customers had smart thermostats and central air conditioning.

Key findings for the CPP-V rate treatments include:

- The reduction in peak-period energy use for Track A customers on critical days equaled almost 16 percent, which is about 25 percent higher than the CPP-F rate average.
- The peak-period reduction for Track C customers equaled roughly 27 percent. About two-thirds of this reduction can be attributed to the smart thermostat and the remainder to price-induced behavioral changes.

Although comparisons between Track A and Track C CPP-V treatments and between the CPP-V and CPP-F treatments must be made carefully due to differences in sample composition, the Track C results suggest that impacts are significantly larger with enabling technology than without it. The 27 percent average impact for the Track C, CPP-V treatment is roughly double the 13 percent impact for the CPP-F rate for the average summer. It is also substantially larger than the

Track A, CPP-V treatment impact, where only some customers took advantage of the technology offer.

D. Residential summary

Table 2[10] summarizes the key findings from the SPP with regard to reductions in peak-period energy use resulting from the various tariff options tested. The most robust and generalizable results were for the CPP-F rate. TOU rate impacts varied across years and are suspect due to sample size limitations and other factors. Although the Track C, CPP-V results are more difficult to generalize to the overall population, they provide useful insight into the incremental impact of prices and enabling technology.

It is interesting to compare the results obtained from the SPP with those that have been found elsewhere. Dozens of studies on the impact of time-varying rates have been conducted over the years, although many of them are quite dated.[11] Very few previous studies examined dynamic rates, which were a key focus of the SPP. Making comparisons across studies is very difficult because of differences in methodology, differences in the characteristics of underlying populations and differences in price levels and other factors. Ignoring such complexities, a simple comparison shows that the SPP estimates of price responsiveness in California are at the low end of the range reported in the literature.

One study, conducted in the early 1980s by the Electric Power Research Institute,[12] allows for a more careful comparison between the SPP results and estimates based on five of the best-designed TOU rate experiments that were conducted in the late 1970s.[13] The EPRI study used a similar demand model specification to the one underlying the SPP, making it easier to estimate the impact of SPP prices using the price responsiveness measures from the EPRI study. Using these earlier model parameters along with average SPP prices, the estimated peak-period reduction on critical days is roughly 70 percent greater than the estimated value from the SPP (i.e., −22.5 percent versus −13.1 percent).

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Table 2: Summary of Average Summer Peak-Period Impacts by Treatment Type for Residential Customers

Treatment	Day Type	Avg. Price (¢/kWh)	Impacts	Comments
Track A CPP-F	Critical weekday	*P* = 59 OP = 9 *D* = 23 *C* = 13	−13.1 percent average summer −14.4 percent inner summer −8.1 percent outer summer −4.7 percent average summer	No statistically significant difference for inner summer between 2003 and 2004 (differences across the two years can not be estimated for the outer summer or the average summer).
	Normal weekday	*P* = 22 OP = 9 *D* = 12 *C* = 13	−5.5 percent inner summer −2.3 percent outer summer	Difference between critical and normal days is primarily due to price differences and secondarily to differences in weather.
Track A TOU	All weekdays	*P* = 22 OP = 10 *D* = 13 *C* = 13	−5.9 percent inner summer 2003 −0.6 percent inner summer 2004 −4.2 percent outer summer 2003/2004	Results are suspect because of the small sample size and observed variation in underlying model coefficients across the two summers. Recommend using normal weekday CPP-F model to predict for TOU rate.
Track A CPP-V	Critical weekday	*P* = 65 OP = 10 *D* = 23 *C* = 14	−15.8 percent average summer 2004 Represents average across households with and without enabling technology —could not separate price and technology impacts	Not directly comparable to CPP-F results due to differences in population (CAC saturation for CPP-V treatment group twice that of CPP-F; CPP-V average income much higher; 2/3 of CPP-V customers had enabling tech; all households located in SDG&E service territory).
	Normal weekday	*P* = 24 OP = 10 *D* = 14 *C* = 14	−6.7 percent average summer 2004	See above comments about population differences.
Track C CPP-V	Critical weekday	Same as for Track A	−27.2 percent combined tech and price impact for average summer 2003/2004 −16.9 percent impact for tech only −11.9 percent incremental impact of price over and above tech impact	Not directly comparable to Track A results due to population differences (all Track C customers are single family households with CAC located in SDG&E service territory). Some evidence that impacts fell between 2003 and 2004.
	Normal weekday	Same as for Track A	−4.5 percent average summer 2003/2004	See above comments about population differences.

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Based on these comparisons, it would appear that price responsiveness in California today is less than it was in California and elsewhere a quarter century ago. This is not surprising in light of the significant conservation and load management programs that were implemented in the last 25 years. Actions taken by many consumers following the energy crises of 2000 and 2001 may also have reduced the ability or willingness of California's customers to further reduce energy use. Nevertheless, it is also very clear from the SPP that there still remains a significant amount of demand response that can be achieved through TOU and dynamic pricing.

III. Commercial and Industrial Customer Response

CPP-V and TOU tariffs were also tested for small and medium C&I customers with billing demands under 200 kW. These tariffs were only tested in the SCE service territory. The C&I population was segmented into two groups, customers with peak demands less than 20 kW (LT20) and customers with peak demands between 20 and 200 kW (GT20). The CPP-V tariff was implemented between two population samples. The Track A sample was recruited from the general population while the Track C sample was drawn from a pre-existing Smart Thermostat pilot. All Track C customers had central air conditioning and smart thermostats. Most Track A customers had central air conditioning but only about half selected the smart thermostat technology option. In light of these and other differences, direct comparisons between Track A and Track C results must be made carefully.

For the Track A, CPP-V treatment, key findings include:

- LT20 customers had a very small but statistically significant demand response, with the average peak-period reduction on critical weekdays equal to 6.0 percent.
- The peak-period reduction on normal weekdays for LT20 customers was roughly 1.5 percent.
- GT20 customers showed a larger percent reduction in peak-period energy use on critical weekdays (−9.1 percent) than did LT20 customers.
- Reductions in peak-period energy use on normal weekdays for GT20 customers equaled 2.4 percent.

Key findings for the Track C, CPP-V treatment include:

- LT20 customers reduced peak-period energy use on critical weekdays by 14.3 percent. All of this reduction was due to the enabling technology. That is, this customer segment did not have any incremental price response.
- GT20 customers reduced peak-period energy use on critical weekdays by 13.8 percent. Roughly 80 percent of this reduction is attributable to the enabling technology.

For the C&I TOU rate treatment, demand response and peak-period impacts varied significantly between summer 2003 and summer 2004. In 2003, price was not statistically significant for the LT20 customer segment. However, price was significant in 2004 and the estimated reduction in peak-period energy use equaled almost 7 percent. Price was statistically significant in both summers for the GT20 segment. Peak period impacts in 2003 equaled −4.0 percent and in 2004 equaled −8.6 percent. These results should be viewed cautiously, however, in light of the small sample size and significant variation in the underlying model coefficients across summers.

Table 3 summarizes the key findings for the C&I analysis. The Track C, CPP-V results suggest that technology could have a relatively significant influence on demand response in the C&I sector, although this population was not representative of the overall population of C&I customers. Demand response among the smallest segment (LT20) was quite small in most instances.

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Table 3: Summary of Average Summer Peak-Period Impacts by Treatment Type for C&I Customers

Treatment/ Customer Segment	Day Type	Avg. Price (¢/kWh)	Impacts	Comments
Track A TOU LT20	All weekdays	$P = 28$ OP = 12 $D = 18$ $C = 18$	−0.3 percent in 2003 −6.8 percent in 2004	The 2003 value was not statistically significant. Small sample size and variation in underlying model coefficients across summers suggest estimates may be suspect. Recommend using normal weekday CPP-F model to predict for TOU rate.
Track A TOU GT20	All weekdays	$P = 23$ OP = 12 $D = 16$ $C = 15$	−3.9 percent in 2003 −8.6 percent in 2004	The difference between 2003 and 2004 was statistically significant. Same caveat as described above for LT20 customers.
Track A CPP-V LT20	Critical weekday	$P = 81$ OP = 12 $D = 30$ $C = 17$	−6.1 percent in 2004	This treatment was not implemented in 2003. Price responsiveness measure was small but statistically significant.
	Normal weekday	$P = 20$ OP = 12 $D = 15$ $C = 17$	−1.5 percent in 2004	Same comments as above.
Track A CPP-V	Critical weekday	$P = 66$ OP = 11 $D = 24$ $C = 15$	−9.1 percent in 2004	This treatment was not implemented in 2003. This segment was more price responsive than LT20 customers.
	Normal weekday	$P = 18$ OP = 12 $D = 14$ $C = 15$	−2.4 percent in 2004	Same comments as above.
Track C CPP-V LT20	Critical weekday	$P = 87$ OP = 12 $D = 33$ $C = 18$	−14.3 percent combined tech and price impact for average summer 2003/2004 −18.2 percent for tech alone +4.5 percent incremental impact of price over and above tech impact	The tech only impact was higher than the combined price/tech impact, indicating that price did not provide any incremental impact for this customer segment.
	Normal weekday	$P = 21$ OP = 12 $D = 16$ $C = 18$	+1.1 in average summer 2003/2004	The estimate was not statistically significant, additional evidence that this customer segment was not price responsive.

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Table 3: *(Continued)*

Treatment/ Customer Segment	Day Type	Avg. Price (¢/kWh)	Impacts	Comments
Track C CPP-V GT20	Critical weekday	*P* = 71 OP = 11 *D* = 24 *C* = 15	−13.8 percent combined tech and price impact for average summer 2003/2004 −11.0 percent for tech alone −3.2 percent incremental impact of price over and above tech impact	Incremental impact of price over technology declined by roughly 75 percent between 2003 and 2004. GT20 participants used significantly less electricity on average than the average control group.
	Normal weekday	*P* = 19 OP = 11 *D* = 14 *C* = 15	−0.9 percent in average summer 2003/2004	Same comments as above.

Responsiveness was greater for GT20 customers than it was for LT20 customers.

IV. Conclusions

California's Statewide Pricing Pilot has demonstrated conclusively that residential and small to medium C&I customers reduce peak-period energy use in response to time varying prices. Price responsiveness varies with climate zone, season, air conditioning ownership, and other customer characteristics. Traditional TOU rates with a peak-to-off-peak price ratio of around 2 to 1 produce peak-period reductions in the 5 percent range for residential customers whereas critical peak prices with ratios in the 5 to 1 and 10 to 1 range produce reductions between 8 and 15 percent with no enabling technology and between 25 and 30 percent with enabling technology.

A series of demand models have been developed using the SPP data that can be used to predict the impact of other prices than those used in the pilot. Equally important, these models can be used to predict the impact of dynamic pricing in other regions of North America and possibly in other developed economies, once adjustments are made for climatic conditions and customer characteristics.

As indicated at the beginning of this article, one of the key reasons for implementing the SPP was to develop estimates of demand response that could be used by California's major utilities to assess the net benefits of wide scale deployment of the Advanced Metering Infrastructure (AMI) required to implement time-varying rates.[14] In March of this year, PG&E, SCE and SDG&E filed preliminary business cases for AMI. Investment costs, operational savings, and demand response benefits vary significantly across the three utilities, as they would for any other utility exploring such a policy. Not surprisingly, the preliminary conclusions and recommendations of each utility also vary.

PG&E found that, in spite of an investment with a present value of revenue requirements equal to roughly $2 billion to replace the Company's 9.3 million gas and electric meters, the demand response benefits outweighed the net costs (equal to roughly $410 million after netting out operational savings) under several potentially achievable assumptions about opt-in participation for dynamic rate programs. SDG&E concluded that such an investment was also attractive, but only if a dynamic rate were implemented on an opt-out basis (that is, customers were placed on the rate as the default option and allowed to switch to a fully hedged, flat or tiered rate

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alternative). SCE came to yet a different conclusion, namely that the demand response benefits were not sufficient to offset the cost of AMI given current technology and costs, but that the net benefits could be positive if additional functionality could be added to the AMI infrastructure at reasonable cost. The company requested funding from the CPUC to help design and develop a new meter that would achieve this goal. These disparate analyses and conclusions highlight both the potential benefits of dynamic pricing and advanced metering as well as the importance of doing the detailed analysis required to determine whether such policies are sensible in light of the unique costs, savings and customer characteristics of each utility.■

Endnotes:

1. Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E).

2. In March of this year, each utility filed updates of preliminary business cases that were originally filed in Oct. 2004 comparing the costs and benefits of advanced metering and pricing reform under various pricing and meter deployment strategies. The results of the SPP were used, in part, to estimate the contribution of demand response to the net benefit calculations for these filings.

3. This article is adapted from the executive summary of our report, *Impact Evaluation of the California Statewide Pricing Pilot, Final Report*, Mar. 16, 2005, that was submitted to Working Group 3. The report can be found at http://www.energy.ca.gov/demandresponse/documents/index.html.

4. See Tables 2 and 3 for a summary of the average prices associated with the experiment.

5. The statewide impact estimate of −13.1 percent has a 95 percent confidence band of ±1 percentage point. This means that there is a 95 percent probability that the actual reduction in peak-period energy use on critical days based on average SPP prices would fall between 12.1 and 14.1 percent.

6. Samples had been optimized using Bayesian techniques to be larger when there would be more value to the information that would be generated. Since there was a large literature on TOU rates and a comparatively small literature on CPP rates, and since CPP rates were likely to be more cost-effective than TOU rates, larger samples were allocated to the CPP cells and smaller ones to the TOU cells.

7. Daily prices varied much more for the CPP-F tariff than the TOU tariff because of the higher prices on critical days with the CPP-F rate.

8. The three options offered were a smart thermostat, an automated water heater control and an automated swimming pool pump control.

9. The Smart Thermostat pilot was an outgrowth of Assembly Bill 970, which was passed in the aftermath of California's energy crisis of 2000–2001.

10. *P* = peak period price; OP = off-peak price; *D* = daily price; *C* = control group price.

11. See Chris S. King and Sanjoy Chatterjee, *Predicting California Demand Response*, PUB. UTIL. FORTNIGHTLY, July 1, 2003.

12. Results from the EPRI study are summarized in Douglas Caves, Laurits Christensen and Joseph Herriges, *Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments*, J. ECONOMETRICS 16 (1984), at 179–203.

13. These included two experiments in southern California and single experiments in Connecticut, North Carolina, and Wisconsin.

14. See Ahmad Faruqui and Stephen S. George, *The Value of Dynamic Pricing in Mass Markets*, ELEC. J., July 2002, at 45.

❖ MEETINGS OF INTEREST ❖

Conference	Date	Place	Sponsor	Contact
Spinning Green Energy into Gold	May 25, 2005	Mechanicsburg, PA	PennFuture	717-214-7920
International Hydrogen Energy Congress	July 13–15, 2005	Istanbul	Hydrogen Energy Forum	http://www.ihec2005.com/
Energy 2005: The Solutions Network	Aug. 14–17, 2005	Long Beach, CA	U.S. Department of Energy	http://www.energy2005.ee.doe.gov/
Air Quality V: Mercury, Trace Elements, SO_3, and Particulate Matter	Sept. 19–21, 2005	Arlington, VA	Energy & Environmental Research Center	(701) 777-5246

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Household Electricity Demand, Revisited

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Recent efforts to restructure electricity markets have renewed interest in assessing how consumers respond to price changes. This paper develops a model for evaluating the effects of alternative tariff designs on electricity use. The model concurrently addresses several interrelated difficulties posed by nonlinear pricing, heterogeneity in consumer price sensitivity, and consumption aggregation over appliances and time. We estimate the model using extensive data for a representative sample of 1300 California households. The results imply a strikingly skewed distribution of household electricity price elasticities in the population, with a small fraction of households accounting for most aggregate demand response. We then estimate the aggregate and distributional consequences of recent tariff structure changes in California, the consumption effects of which have been the subject of considerable debate.

1. INTRODUCTION

Recent efforts to restructure electricity markets have renewed interest in electricity demand and pricing. This interest reflects a broad desire to improve the efficiency of electricity markets, and policy-makers' concerns over the impact of price changes on consumers. How new pricing mechanisms would affect households' consumption and expenditures is a matter of considerable uncertainty, however. This uncertainty has provoked controversy and debate in the regulatory policy arena, hampering market reforms.

Using econometric methods to assess the effects of electricity price changes presents several challenges. These include the nonlinear structure of tariff schedules, aggregation of metered consumption behaviour over time and appliances, and the interdependence of energy use with longer-term household decisions over appliance ownership and dwelling characteristics. The first two issues introduce complex simultaneity problems between marginal prices and consumption. The third issue imposes high data requirements (information on household-specific appliance holdings and residence features), and creates heterogeneity in consumption responses related to the characteristics of these durable goods. When the researcher's objective is to develop a model for simulating the effects of prospective tariff changes, ignoring these issues will provide an incomplete assessment of demand responses and potentially misleading predictions of a new tariff's consumption and revenue consequences.

In this paper, we estimate a model of household electricity demand that can be used to evaluate alternative tariff designs. The model focuses on the heterogeneity in households' demand elasticities, their relation to appliance holdings and other household characteristics, and how they inform household consumption responses to complex (nonlinear) price schedule changes. Although these issues have received attention in the literature, few (if any) studies have

addressed them in an integrated way.[1] This shortcoming is notable in that theory suggests that the effects of an alternative tariff design on a diverse population will depend on the heterogeneity in consumers' price elasticities as well as their consumption levels. We address these features using a model of endogenous sorting along a nonlinear price schedule, and a group-wise specification of price-sensitivity heterogeneity based on household appliance ownership. This model reveals a rich, highly asymmetric shape to the population distribution of households' price elasticities. It also indicates a larger aggregate price elasticity of residential electricity demand than prior studies that ignore these issues.

We estimate the model using data for a representative probability sample of California households from the *Residential Energy Consumption Survey* of the U.S. Department of Energy. The rich detail on appliance holdings and dwelling characteristics in these data allow us to model the considerable variation in households' electricity use and sensitivity. We have supplemented the *Survey* by matching each sample household with its complete, seasonally varying electric rate schedule. The use of precise rate schedule information is a central feature of the analysis, both to minimize specification error in estimation and to evaluate individual behavioural responses to alternative rate structures. To lend credence to the specifications and results, we conduct out-of-sample tests of the model that show how well it predicts consumption responses to new price changes.

We then use the model to study the effects of a controversial new tariff design in California. Following an electricity supply crisis in 2000–2001, regulatory authorities approved a novel, five-part tariff structure for residential electricity consumption. This design was intended to induce energy conservation, raise additional revenue for utilities, and minimize expenditure changes for lower-income households. Due to its unprecedented form, however, little was known about how well the new system would achieve these objectives prior to its adoption. We show how such uncertainties can be evaluated prospectively using the sample data, and contrast our estimates with methods employed by public agencies in California and elsewhere.

The next section lays the econometric groundwork for our empirical methods, and highlights how our approach differs from prior studies. Our treatment of the endogenous sorting problem that occurs with nonlinear prices builds upon Hanemann's (1984) and Hausman's (1985) choice models given nonlinear budget constraints. Our approach also handles two important aggregation-related problems common to electricity demand research. Section 3 then develops the empirical specification. Following prior work, this model explains heterogeneity in households' electricity price elasticities in terms of appliance holdings and use. Section 4 discusses estimation via an exact nonlinear method of moments, and Section 5 summarizes the data. Sections 6 and 7 present estimation results and elasticities, including out-of-sample validation tests of the model. In Section 8 we then illustrate how the model and methods lend themselves to analysing prospective tariff design changes, such as California's complex new tariff structures.

2. MODELLING DEMAND WITH NONLINEAR PRICES

Although economic theory offers considerable guidance on how consumers will respond to nonlinear prices, econometric treatments of estimation and identification in this setting remain

1. Taylor (1975) contains an early treatment of nonlinear tariffs in empirical work. More sophisticated methods followed Burtless and Hausman's (1978) work on closely related issues in the analysis of labour supply under nonlinear income taxation. Surprisingly little of these econometric techniques have permeated the (considerable) literature on electricity demand; notable exceptions are Maddock, Castano and Vella (1992) and Herriges and King (1994). A greater consensus has emerged on the importance of incorporating household-level appliance stock information into electricity demand analyses, as well as empirical methods for doing so; see Parti and Parti (1980), Dubin and McFadden (1984), Dubin (1985), and EPRI (1989).

incomplete. This section summarizes the problems inherent in prior estimation strategies, motivates and describes our econometric approach, and connects it to related econometric literatures.

2.1. *Specification and identification*

Most nonlinear price schedules take the form of multi-part tariffs. Since Gabor (1955), economists have realized that multi-part tariffs imply that the consumer faces a nonlinear (*i.e.* a kinked) budget constraint. The demand behaviour of a utility-maximizing consumer thus depends not on the average price, nor any single marginal price, but on the entire price schedule. The standard econometric approach to demand analysis in this setting, which traces to Hall (1973), is to "linearize" the budget constraint. This amounts to using the plane tangent to the consumer's nonlinear budget constraint at the optimal consumption bundle as its linear approximation. By doing so, one can express demand under nonlinear pricing in terms of the ordinary demand function of classical consumer theory, which assumes a linear budget constraint.

To be specific, let $x(p, y)$ be the ordinary demand function that indicates the consumer's desired quantity facing a constant (marginal and average) price p and income y. Suppose, however, that the consumer faces an increasing price schedule $s(p)$ of the form depicted in Figure 1. Here the consumer pays a low price p_1 for each unit up to the quantity $\bar{x}$, and a higher price p_2 thereafter. Then the optimal consumption level x^* satisfies

$$x^* = x(p^*, y^*) \tag{1}$$

where p^* is the slope of the approximating linear budget constraint and $y^* = y + \bar{x} \cdot (p^* - p_1)$. In economic terms, p^* is the consumer's equilibrium marginal willingness-to-pay and y^* is the income level that would induce consumption x^* at this (constant) price. With (1), the demand specification problem under nonlinear pricing can be recast in terms of the ordinary demand function familiar to applied work. Note that both p^* and x^* are endogenously determined, according to the three-equation system consisting of (1), the expression for y^*, and the nonlinear price schedule $s(p^*)$.[2]

Nearly all previous studies of household electricity demand have based estimation—either implicitly or explicitly—on a single-equation analogue of equation (1). Because the marginal price is simultaneously determined by a supply equation and a demand equation, standard econometric arguments imply that ordinary least squares estimation using p^* will yield biased and inconsistent estimates of demand parameters. Recognizing as much, most previous studies have used either an exogenous proxy for the marginal price or instrumental variables (IV) procedures in estimation. While either method can alleviate the endogeneity problem, both introduce biases of their own: the former due to mis-specification of the appropriate marginal price, and the latter because of the difficulty in finding good instruments (that do not *a priori* belong in the demand equation) in this setting.

To elaborate on the latter point, the natural set of instruments in this context are the components of the price schedule itself. This idea appears in early work by McFadden, Puig and Kirshner (1977) and others. An important shortcoming of this approach, however, is that there may be little or no price schedule variation in the data. This is a common situation in nonlinear pricing applications, as the data are often provided by a single firm that charges either one tariff,

2. The analysis with a decreasing price schedule is slightly more complex, because of the possibility that demand may have multiple crossings of the price (supply) schedule. In that event, these three equations have multiple solutions and a fourth equation (involving the indirect utility function) is needed to determine consumption. This analysis is feasible if the econometric demand specification admits a known indirect utility function; see, *e.g.* Hausman (1985).

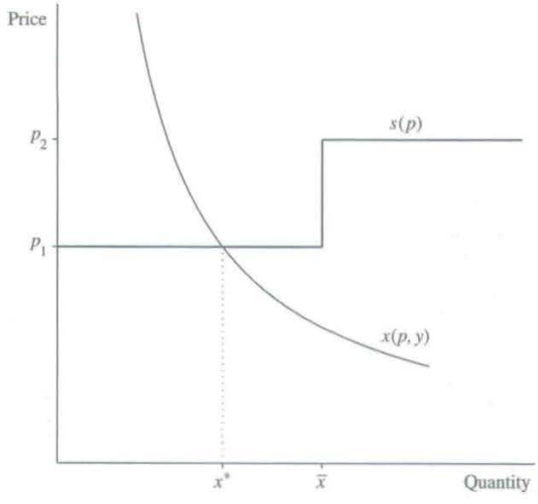


FIGURE 1
An increasing two-tier price schedule

or a few very similar ones, to all consumers. Researchers thus face a canonical weak instruments problem that can result in imprecise and misleading price-elasticity estimates.[3]

A second, and more general, concern arises when consumption decisions are aggregated over time or over distinct services. In the presence of nonlinear pricing, such aggregation often makes IV procedures infeasible.[4] For example, when the consumption data are aggregated over billing periods, the consumer's actual marginal prices are typically not observed. Thus there is no way to construct a proper IV estimator: the endogenous (sequence of) marginal prices are not available to project onto any instrument. Similar difficulties arise if consumption outcomes are aggregated over nonlinearly priced goods or services, rather than over time.[5]

Data aggregation problems of this sort are nearly universal in electricity demand studies. They occur both because a household's electricity meter aggregates consumption of numerous distinct appliance "services" (addressed further in Section 3), and because publicly available data often record consumption over annual (or other) intervals covering multiple billing periods. The predominant treatment of this latter issue in the literature has simply been to ignore it, proceeding as if the household faced a constant (marginal) price over the course of the year. This not only mis-specifies the prices consumers face, it assumes away the economic effects of interest.

In this paper we handle these difficulties in an integrated way. The starting point is the true reduced form of the "supply equals demand" equilibrium condition in (1); that is, solving the three-equation system above for x^* as a function of the price schedule. We do so here assuming the consumer's ordinary demand function (demand at a constant price p) takes the

3. Dubin (1985) shows that ignoring simultaneity problems can produce substantially biased electricity demand elasticities. Maddock *et al.* (1992) show that one common IV approach fails to correct well for the simultaneity bias, resulting in estimated price elasticities that are biased toward the slope of the supply curve.

4. We thank an anonymous referee for emphasizing this point.

5. This problem also arises in other econometric applications. An example is the analysis of aggregated retail scanner data for consumption goods, which are often sold using nonlinear forms of pricing (volume discounts, limited-quantity coupons, 2-for-1 offers, etc.). Policy-makers that use such data are now evidently aware of these aggregation biases; see FTC (2002).

econometric form

$$x(p, y, z, \varepsilon; \beta) \tag{2}$$

where z represents observed consumer characteristics, ε unobserved consumer characteristics, and β a set of parameters to be estimated. To avoid unnecessary technicalities, assume demand is strictly increasing in ε and strictly decreasing in p.

Facing an increasing two-tier price schedule, the reduced form for the household's consumption level x^* as a function of the price schedule is

$$x^* = \begin{cases} x(p_1, y, z, \varepsilon; \beta) & \text{if } \varepsilon < c_1 \\ \bar{x} & \text{if } c_1 < \varepsilon < c_2 \\ x(p_2, y_2, z, \varepsilon; \beta) & \text{if } \varepsilon > c_2 \end{cases} \tag{3}$$

where $y_2 = y + \bar{x} \cdot (p_2 - p_1)$ and c_j is the solution to $x(p_j, y_j, z, c_j; \beta) = \bar{x}$ with $y_1 = y$ (that is, c_j is the maximum (for $j = 1$) or minimum (for $j = 2$) value of ε for which consumption occurs on tier j). Equation (3) states that consumption is given by demand at the low price if the first tier is on the margin, by demand at the high price plus an income effect if the second tier is on the margin, and by the quantity $\bar{x}$ when demand crosses supply in the "gap" between the two tiers of the price schedule.[6] The lower and upper cut-off values c_1 and c_2 satisfy $c_1 < c_2$ for any downward-sloping demand function, provided that income effects are not too large.[7]

It is useful to be clear about why estimating the single reduced-form equation (3) can separately identify the effect of price on demand and supply (*e.g.* β in (2)). Intuition from classical supply-and-demand simultaneity in linear econometric models suggests that additional exclusion restrictions are necessary—tantamount to assuming that viable instruments are available. With nonlinear pricing problems, however, this is not the case. Demand is identifiable here because (i) the supply schedule has constant-price segments, and (ii) the conditional distribution of ε (given the marginal price) is computable. Intuitively, one can use the variation in consumption among all households on the *same* tariff segment to identify the non-price components of demand.[8] Given that, the effect of price can be determined from the remaining difference in average consumption between households on *different* tariff segments, less the average difference in their unobserved characteristics. The latter is computable from the marginal distribution of ε and the price schedule. Researchers can therefore estimate demand without price schedule variation, provided one is willing to place some distributional restrictions on ε. Of course, when there is price schedule variation in the data, this will provide a second "source of identification" for the demand specification (2).

In sum, by solving-out the marginal price to obtain (3), the simultaneity problems arising in econometric analyses using (1) can be avoided. In addition, if one proceeds from an empirical specification of the ordinary demand function that is consistent with (or perhaps derived from) a utility specification, then (3) indicates precisely how the individual terms of a nonlinear price

6. The term $\bar{x} \cdot (p_2 - p_1)$ that is added to income in the third case in (3) is the infra-marginal price discount: the difference between the expenditure necessary to purchase the higher quantities $x^* > \bar{x}$ under nonlinear pricing, and that necessary to purchase x^* at a constant price of p_2.

7. Technically, the case conditions in (3) are correct only if certain restrictions on preferences hold. For a normal good (one whose consumption rises with income), these amount to assuming that the income effect is not "too large"; or, more specifically, that the income effect of the infra-marginal discount does not dominate the substitution effect of the higher marginal price. If this fails, the conditioning-event inequalities on the R.H.S. of (3) are more complex.

8. This argument ignores income effects (cf. note 7) and confounding due to aggregation over time (more about which further below).

schedule enter the demand decision. This provides a framework for predicting how consumption would change under an entirely different price schedule.

2.2. *Estimation issues*

From an econometric perspective, equation (3) is a nonlinear censored regression model in which the censoring occurs in the interior of the distribution of outcomes rather than the tails. Such models are generally estimated by maximum likelihood methods, using the discrete structure in (3) to derive the change-of-variables from an (assumed) marginal distribution of ε to the distribution of x^*. Burtless and Hausman (1978), with later extensions by Hausman (1985), Moffitt (1986), and others, develop likelihood functions for models with this structure. Unfortunately, maximum likelihood estimation quickly becomes computationally intractable when the consumption outcomes from a mixed discrete/continuous model are aggregated over time. This problem renders likelihood methods infeasible for our application.[9] Consequently, we pursue a moment-based approach to estimation.

Conditional on the observables, (3) can be integrated piecewise to obtain

$$E(x^* \mid \cdot) = E_\varepsilon[x(p_2, y_2, z, \varepsilon; \beta)] + h(p_1, p_2, \bar{x}, y, z; \beta) \tag{4}$$

where $h(\cdot) \equiv \tau_2 - \tau_1$ is a sorting correction function defined by the truncated moments

$$\tau_j = \int_{-\infty}^{c_j(\beta)} [\bar{x} - x(p_j, y_j, z, \varepsilon; \beta)]\, dF_\varepsilon, \qquad j = 1, 2, \tag{5}$$

with c_1, c_2 defined in (3) and $y_1 = y$. These expressions do not place restrictions on $x(\cdot)$ or how ε enters it (beyond integrability of demand and monotonicity in ε). Although complex in the general form, the moments in (5) that correct for the nonlinearity of the price schedule are straightforward to evaluate for most error specifications in applied work. For example, if F_ε is $N(0, \sigma^2)$ and ε enters demand (2) additively, then expected consumption simplifies to

$$\begin{aligned} E(x^* \mid \cdot) = {} & [x(p_1, y, z; \beta) - \sigma\lambda_1]\Phi_1 + \bar{x} \cdot (\Phi_2 - \Phi_1) \\ & + [x(p_2, y_2, z; \beta) + \sigma\lambda_2](1 - \Phi_2) \end{aligned} \tag{6}$$

where Φ_j is the standard normal distribution evaluated at $c_j(\beta)/\sigma$, ϕ_j the normal density at $c_j(\beta)/\sigma$, $\lambda_1 = \phi_1/\Phi_1$, and $\lambda_2 = \phi_2/(1 - \Phi_2)$.

Equation (6) highlights a useful parallel to more familiar econometric selection models. The terms in square brackets in (6) correct for the fact that, given the observables, consumers that sort onto the lower marginal price are different in their unobservable characteristics from those who choose the higher-tier price. This parallels conventional sample-selectivity problems inasmuch as the econometric complications in both settings stem from endogenous sorting along a budget constraint. Unlike traditional models of labour supply (such as Heckman, 1974), however, here the sorting occurs between segments of a nonlinear budget constraint. This situation generates greater information about the distribution of consumer preferences than sorting between interior and boundary solutions along a linear constraint, which makes (4) more complex than standard selection–correction models.[10]

9. To illustrate, the likelihood function for a single (monthly) consumption outcome x^* of the model (3) is a mixed continuous/discrete function with three discrete segments (one for each case in (3)). The likelihood function for the sum of 12 months' consumption outcomes therefore involves 3^{12}, or 531,441 distinct segments. While there is some redundancy involved, the task of evaluating such a likelihood function (for use in either direct or simulated likelihood methods) appears quite burdensome.

10. At the risk of confusing matters, there is one other difference between the present analysis and traditional models of labour market supply. The analysis here is more complicated because the supply and demand system is non-

The moment expressions in equations (4) and (5), and its interpretation as a selection problem, suggest that it might be possible to take a semi-parametric approach to estimating this model (following Ichimura (1993) or Das, Newey and Vella (2003)). Such methods are not designed to handle situations, such as ours, where there is no ancillary selection information about which segment of the budget constraint is marginal. That is, there are no covariates that predict a household's tariff tier that can be *a priori* excluded from the demand specification. One paper that appears to have made progress in this area is Blomquist and Newey (2002), in the context of modelling labour supply decisions subject to nonlinear income taxation. Their non-parametric approach does not appear adaptable to the present setting, unfortunately, for two reasons. First, identification appears to require considerable cross-sectional variation in price schedules across sample observations. While not a problem for the labour supply context (due to wide wage dispersion), this is a significant limitation in nonlinear pricing applications. The second, and more subtle, issue is that the non-parametric literature cannot yet handle cases where the observed outcome is the aggregation of several distinct consumption decisions that are interdependent. Demand is then implicitly defined by an equilibrium relation for which the marginal effects (of price schedule changes) may not be non-parametrically identified. Such a structure is inherent in electricity demand analyses, due to the aggregation of consumption across appliances.[11]

These considerations necessitate a parametric approach to modelling F_ε in nonlinear pricing problems, at least in our context. In estimation we use (6), which fits our data well. In general, restrictions on F_ε sufficient to evaluate the truncated moments in (5) are necessary to estimate demand elasticities and other quantities dependent on (2), in the absence of considerable (and exogenous) variation in price schedules. This, of course, raises the issue of whether such restrictions are valid for the particular application at hand. We take a formal approach to validating our model using out-of-sample testing in Section 7.

2.3. *Aggregation over time*

A method of moments framework also allows us to handle complications posed by data aggregation over time. In practice, electricity tariffs apply to households' consumption on a monthly basis. In contrast, the data available to us provide only *annual* household electricity consumption. This temporal mismatch is a potential source of bias, as the effects of prices and other time-varying covariates will tend to be confounded in the data. For example, a decrease in a household's cumulative demand over a period of several cooler-than-usual summer months could be due solely to the effect of weather, or due to an increase in seasonal electricity tariffs during the summer, or due to a composition of these two simultaneous effects. With only annual data, it is difficult to disentangle and separately identify the direct effect of marginal price changes. Yet estimating this effect is precisely what is required if we are to measure the effects of changing (monthly) tariff schedules.[12]

recursive. That is, in traditional labour supply models, the individual's labour supply function depends on the market wage, but the market wage is constant irrespective of the labour hours supplied. The slope of the budget constraint is therefore exogenous. In the present analysis, the quantity demanded depends on the marginal price (through substitution behaviour) and the marginal price depends on the quantity consumed (through the price schedule). This feature eliminates triangular-system approaches to estimation (*e.g.* Newey, Powell and Vella, 1999).

11. To elaborate, aggregation across appliances implies that a household's electricity demand x^* takes the implicit form $x^* = \sum_k f_k(p(x^*), z)$, where $p(x^*) \in \{p_1, p_2\}$ is the marginal price (which depends on total consumption) and f_k is the demand for the k-th appliance's services. Projecting observed values of x^* onto $\{p_1, p_2, z\}$ non-parametrically describes the equilibrium relation between these variables, not the marginal effect of changing the price schedule on demand. The latter is the effect of empirical interest.

12. Similar temporal aggregation problems occur in other contexts, such as when workers' wages are determined weekly (including overtime), but only monthly or annual data are available.

Addressing this problem constructively requires modelling each monthly consumption outcome, in order to avoid mis-specifying the prices consumers actually face. It also requires information on how demand conditions changed during the year. To be precise, let w_t denote the observable variables affecting consumption in month t, including the applicable price schedule and that month's weather conditions. Let x_t^* denote the household's electricity consumption in month t, and $x^a = \sum_{t=1}^{12} x_t^*$ the household's annual electricity consumption. The value of x_t^* for month t is determined by (3), using the R.H.S. covariates for that month.

To estimate the model we require an expression for the expected value of annual demand, $E[x^a \mid w_1, w_2, \ldots, w_{12}]$. Exploiting linearity of expectations, we assume

$$E[x^a \mid w_1, w_2, \ldots, w_{12}] = \sum_{t=1}^{12} E[x_t^* \mid w_t], \tag{7}$$

where $E[x_t^* \mid w_t]$ is as defined in (6).[13] That is, we evaluate the (conditional) expectation of annual demand by evaluating the monthly consumption equation 12 times, using the appropriate covariates for each month. There is no simple form for otherwise calculating the expected value of annual demand.

In the empirical analysis of demand behaviour, the expected consumption equations (6) and (7) serve two roles. They can be used to estimate a model of demand that avoids aggregation biases when consumers face nonlinear tariffs of the form in Figure 1; and, given the estimated demand model, they can be used to predict how consumption would differ under an alternative tariff structure. Proceeding to the first of these objectives next, we now consider the specification of a household electricity demand function, $x(p, y, z, \varepsilon; \beta)$.

3. HOUSEHOLD ELECTRICITY DEMAND

Like many household services, electricity is not consumed directly. Rather, electricity demand is derived from the flow of services provided by a household's energy-using appliances. The durability of these appliances creates a distinction between short-run and long-run demand elasticities. The "short-run" refers to demand behaviour taking a household's existing appliance stock as given. For example, in response to an increase in the price of electricity, a household might tolerate a warmer air conditioner setting or reduce the number of hours a pool filter operates. In contrast, long-run elasticities incorporate both changes in utilization behaviour and any adjustments to the stock of appliances owned by the household.

This distinction has important consequences for modelling demand behaviour. The long-run effects of electricity price changes are an equilibrium outcome of households' appliance replacement decisions (on the demand side) and appliance manufacturers' choices of technological characteristics and prices for new appliances (on the supply side). Like most prior studies, however, our (cross-sectional survey) data do not contain the longitudinal information necessary to estimate how these replacement decisions are prompted by changing energy prices. Thus, we focus on analysing short-run demand elasticities, and leave appliance replacement decisions for subsequent research. Our results therefore describe changes in demand

13. Equation (7) makes a subtle separability assumption about the conditioning sets, which affects household substitution behaviour over time. If we assume that households consume electricity out of permanent rather than contemporaneous (*i.e.* monthly) income, the only time-varying elements in w_t are the monthly weather-related covariates and the price schedules (being seasonal). Equation (7) makes the implicit assumption that, conditional on a household's existing appliance stock, knowledge of the electricity price schedules and weather patterns for past and future months this year has no effect on the current month's consumption. While untestable directly, this is a plausible assumption since households cannot store electricity.

due to changes in appliance utilization behaviour, rather than equilibrium appliance stock adjustments.[14]

This approach to modelling electricity demand amounts to conditioning on households' existing appliance stocks. Since households vary markedly in the set of appliances they own, however, the factors influencing electricity demand in one household may differ significantly from those in the next. We address such heterogeneity by specifying electricity demand functions at the level of the individual appliance.[15] Because we do not observe the electricity consumption of individual appliances, but rather total household electricity consumption, we treat the electricity used by each of a household's individual appliances as a latent outcome. We then aggregate these appliance-level demand specifications to model household electricity demand.

Specifically, we treat total household demand as the sum of electricity used by K distinct appliance categories. These categories include space heating, water heating, air conditioning, refrigeration, pools, and the like. If a household owns an appliance of type $k = 1, 2, \ldots, K$, we assume that electricity consumption (per billing period) for the category, x_k, takes the linear form

$$x_k = \alpha_k p + \gamma_k y + z_k' \delta_k + \varepsilon_k \tag{8}$$

where p is the price of electricity, y household income, z_k a vector of observable household characteristics, and ε_k unobservable household characteristics. The unknown demand parameters α_k, γ_k, and δ_k are assumed constant across households. Depending on the appliance, the category-specific vector z_k may include household demographic information, dwelling structure characteristics, appliance attributes, and (contemporaneous billing-period) weather data. We interpret equation (8) as household demand when it faces a constant (marginal and average) price, p.

Since a household's total electricity demand is the sum of its appliances', we can aggregate (8) to obtain

$$x = \sum\nolimits_k d_k \alpha_k p + \sum\nolimits_k d_k \gamma_k y + \sum\nolimits_k d_k z_k' \delta_k + \sum\nolimits_k d_k \varepsilon_k, \tag{9}$$

where x is total household electricity consumption, $d_k = 1$ if the household owns appliance type k, and $d_k = 0$ if otherwise. This is conveniently rewritten as

$$x = \alpha p + \gamma y + z' \delta + \varepsilon \tag{10}$$

by setting $\alpha = \sum_k d_k \alpha_k$, $\gamma = \sum_k d_k \gamma_k$, and so on. Although equation (10) looks like a conventional linear demand function, the price, income, and other slope coefficients depend upon the household's appliance portfolio. Notice that we are not estimating α directly, but rather the parameters $\alpha_1, \alpha_2, \ldots, \alpha_K$ that characterize the price-sensitivity of each appliance category (and similarly for γ, δ). Thus, this specification allows households with numerous electricity-intensive appliances, such as air conditioners, swimming pools, or electric space heating systems, to exhibit different price and income elasticities than households without such appliances.[16]

14. The element of technological change in appliance manufacturers' choices makes estimating the long-run effects of electricity price changes particularly complex. One effort to do so is the EPRI Residential End-Use Energy Planning System (REEPS) micro-simulation models; see Goett and McFadden (1984). These models build on Dubin and McFadden's (1984) model of contemporaneous appliance choice and utilization decisions.

15. This latent-variables approach to modelling electricity consumption is implicit in Fisher and Kaysen's (1962) pioneering work on aggregate electricity demand. Later studies using related approaches include Parti and Parti (1980), Barnes, Gillingham and Hagemann (1981), and Dubin (1985). The present approach is sometimes termed "conditional demand analysis" in the literature (see especially EPRI, 1989 and references therein); we avoid this usage because it conflicts with similar terminology in econometric multi-level budgeting models.

16. A separate issue not examined here is that the choice of major appliances in a residence is ultimately endogenous, and may be statistically endogenous to a model of utilization behaviour. Dubin and McFadden (1984)

Equation (10) corresponds to the conventional demand function $x(p, y)$ of classical consumer theory. That is, it specifies the amount of electricity the household would consume *if* it faced income level y and a constant price p for electricity. Since the sample households face nonlinear price schedules, the optimal consumption level is given by evaluating demand using equation (3). The expected value of demand is similarly determined, by appropriately inserting the demand specification (10) into the expected consumption equation (6).

Variances. An important aspect of this model is that the household-level demand error, ε, is heteroscedastic. This occurs because the stochastic term in the household-level demand specification is the sum of the stochastic terms associated with the K appliance utilization equations (8). Specifically, from equations (8) to (10), the variance of the household-level stochastic term is a function of the appliances owned:

$$\begin{aligned} \operatorname{var}(\varepsilon) &= \sum\nolimits_{j=1}^{K} \sum\nolimits_{k=1}^{K} d_j d_k \operatorname{cov}(\varepsilon_j, \varepsilon_k) \\ &\equiv \sigma(d_1, d_2, \ldots, d_K)^2. \end{aligned} \tag{11}$$

We think of the appliance-level stochastic terms as reflecting households' idiosyncratic tastes for utilizing appliances. A variety of behavioural considerations then suggest that the covariance terms entering (11) will tend to be positive, so that the variance of the household-level stochastic term will increase with the number of appliances owned.

From an econometric perspective, equation (11) is a simple model of group-wise heteroscedasticity in which the "group" is a specific portfolio of household appliances. Normally, this would not be a major concern for estimating the parameters of a linear demand specification such as (10). When consumers face nonlinear prices, however, the variance of the household-level stochastic term affects the likelihood that a consumer will fall on one tariff segment or another. This can be seen immediately from equation (6), where (the root of) the variance term, σ, enters the conditional expectation function and the tariff segment probabilities. The heteroscedastic variance of unobserved tastes thus affects expected consumption calculations and estimation of all the demand parameters.

4. ESTIMATION DETAILS

The foregoing discussion suggests a straightforward, albeit nonlinear, least-squares procedure for estimation. This is to choose as estimates the values of the unknown parameters that minimize the difference between the observed and expected annual consumption outcomes. Unfortunately, for some realizations of the data (including ours), the conditional expectation function (6) may be nearly flat with respect to σ near its true value. In essence, the first moments of the sample may contain too little information to estimate the variance components in (11) accurately. To resolve this problem, it is necessary to incorporate additional information into estimation.

We employ a generalized method of moments (GMM) procedure based on first- and second-moment differences between observed and expected annual consumption:

$$\begin{aligned} u_1 &= x^a - h_1(\mathcal{W}, \theta) \\ u_2 &= (x^a)^2 - h_2(\mathcal{W}, \theta) - 2\,h_1(\mathcal{W}, \theta)\,(x^a - h_1(\mathcal{W}, \theta)), \end{aligned}$$

present some evidence on this issue for gas vs. electric home heating systems. In earlier work we attempted to account for this possible endogeneity in a homoscedastic model (where the household-level error did not depend on the appliances owned; cf. equation (11)). For appliance instruments we used 30-year averages of local weather data. The results from this model did not differ noticeably from an un-instrumented homoscedastic model.

where $h_r(\mathcal{W}, \theta) = E[(x^a)^r \mid \mathcal{W}]$ denotes the r-th conditional moment of annual consumption, θ the unknown parameters to be estimated, and $\mathcal{W}$ all observable variables influencing the household's annual consumption. The second equation bases inference on the centred second moment of annual consumption.[17] Let β denote the demand parameters from (10) and ξ a vector of variance terms from (11), so $\theta = (\beta, \xi)$. Since optimal instruments in this setting involve (covariance-weighted) derivatives of the conditional moments h_1 and h_2, we set

$$z_1(\mathcal{W}, \theta)' = \nabla_\beta\, h_1(\mathcal{W}, \theta) \qquad \text{and} \qquad z_2(\mathcal{W}, \theta)' = \begin{bmatrix} \nabla_\beta\, h_2(\mathcal{W}, \theta) \\ \nabla_\xi\, h_2(\mathcal{W}, \theta) \end{bmatrix},$$

and base estimation on the orthogonality conditions $E[z_r' u_r] = 0$, $r = 1, 2$.[18] Note that the gradient of h_1 with respect to the variance parameters is excluded from the instruments, for the sample analogue contains no useful information (it is essentially singular—this is the reason the variance parameters are not identified by (6) alone).[19]

The functional form of $h_1(\mathcal{W}, \theta)$ is given by (6) and (7). The functional form of $h_2(\mathcal{W}, \theta)$ is derived similarly, and involves the second moment of the truncated normal distribution. In doing so, an additional complication arises due to temporal aggregation of consumption. While computing h_1 involves only the mean and variance of the stochastic term ε in the underlying monthly demand specification, evaluating h_2 requires an assumption about the correlation of ε over time. We assume that the value of ε in the household's demand specification (10) is independent from month to month. Jointly estimating an autocorrelation structure for the 12 monthly unobservables appears impractical with annual consumption data.

Estimation sequentially minimizes the metric $||A\, u(\theta)||^2$, where A is a weighting matrix held fixed during each minimization, and $u(\theta)' = [u_1(\theta)'\ u_2(\theta)']$ is the $2n$-vector of "stacked" first and second conditional moment differences for all n households. The matrix $A = \tilde{R}\,\tilde{Z}'D$, where D is a diagonal matrix containing the survey sampling weight for each observation, $\tilde{Z}$ the matrix of instruments evaluated at an initial (consistent) estimate of θ, and $\tilde{R}$ the (Cholesky) root such that $\tilde{R}'\tilde{R} = [D\tilde{Z}'\tilde{\Omega}\tilde{Z}D]^{-1}$. Here $\tilde{\Omega}$ is the true covariance function matrix $E[u(\theta)u(\theta)' \mid \mathcal{W}]$, evaluated at the initial estimate of θ. These covariance functions are directly computable (the non-zero elements being the second through fourth conditional moments of annual consumption), and we use their analytic expressions in estimation.

To obtain final parameter estimates, we iterated minimization of the GMM distance metric six times using successive updates of the matrix A. Full optimization required approximately three minutes on a 2·0 GHz computer, with 270 moment equations and 212 estimated parameters. Numerical optimization was performed using an efficient trust-region subspace minimization algorithm (Nocedal and Wright, 1999) and implemented in Matlab.

5. DATA AND EMPIRICAL SPECIFICATIONS

We estimate the model using data from the *Residential Energy Consumption Survey* (RECS). The RECS is conducted every three to four years by the U.S. Department of Energy to collect information on household appliances and energy use. The survey is a nationally representative

17. Centring (via the cross-product term $-2h_1(x^a - h_1)$) considerably improves sampling precision: if $(x^a)^2 > h_2$ then the cross-product term tends to be negative, and conversely if $(x^a)^2 < h_2$, which reduces the sampling variance of u_2.

18. It may be verified by direct analysis that these instruments preserve a unique solution for θ to equations $E[z_r' u_r] = 0$, $r = 1, 2$, provided that the variance function $\sigma(d_1, d_2, \ldots, d_K)^2$ is bounded away from zero.

19. In estimation we use a re-parameterization of the variance function (11) that facilitates estimation but at the cost of increasing the number of parameters. Estimation is easier because the re-parameterized GMM objective function is orthogonal in each of the 154 variance parameters. This re-parameterization imposes positive definiteness but otherwise places no restrictions on the covariance matrix in (11).

probability sample of households, with representative subsamples for several large states. We use the California subsamples of the 1993 and 1997 survey waves. Together they provide information on 1307 California households.

The survey is conducted through in-home interviews. Interviewers inventory the household's appliances, assess physical characteristics of the residence, and collect demographic information. The survey also includes weather data (heating and cooling degree-days) for each household, which are obtained from the nearest National Weather Service (NWS) station during the survey year. Each household's metered energy consumption data are collected by the survey directly from its electric utility. Further details about the RECS data and survey design are available in EIA (1994, 1996).

The appliance information, representativeness, and quality of the consumption data make the RECS particularly valuable for analysing household electricity demand. There are, however, two noteworthy shortcomings of the RECS data. The first is that the RECS public-use files only provide *annual* household electricity consumption and expenditures, as noted in Section 2. The second shortcoming pertains to the limited electricity tariff information available in the survey. Inadequate pricing data are a first-order problem for many previous studies of electricity demand and for other researchers using the RECS. Our considerable efforts to rectify this problem merit a brief digression here.

5.1. Prices

During the sample period most California households faced an increasing two-tier electricity price schedule each month, such as the one depicted in Figure 1. These schedules vary by service provider, climate zone, household heating system, household income, and season. For example, the state's largest utility, Pacific Gas and Electric (PG&E), had 72 variants of its standard residential rate schedule in effect during 1993 and 1997. A similar structure applies to the state's other major utilities.

The RECS data provide two summary price measures for each household. The first is the household's annual average electricity price, in cents per kilowatt-hour. The second is the local electric utility's annual average revenue per kilowatt-hour sold to all its residential customers. Either of these price measures unfortunately presents problems for modelling electricity demand at a disaggregate (household) level. As noted in Section 2, the first of these two price measures is endogenous (it rises with consumption) and bears a complex relation to the household's monthly use. The second, utility-level average price, while putatively exogenous, will typically mis-measure the actual marginal price faced by a household. Either summary price measure could therefore be expected to provide poor information regarding the marginal price facing the household each month, and thus biased price elasticity estimates.

To address these shortcomings, we developed a procedure for matching each observation in the RECS with the complete rate schedule facing the household. The data this requires that are not provided in the RECS are each household's utility and its utility-designated climate zone. To determine these, we exploit three types of information in the RECS about the household: the local utility's average electricity price, the availability and price of natural gas, and the weather information. The weather data provide considerable information regarding where in California's diverse climate zones each household is located. The utility-level electricity and natural gas price data then help pinpoint the household's service provider.

To match each RECS household to its utility and climate zone, we first used maps of utility service areas to assign each of the approximately 240 NWS stations in California to one (or two adjacent) utility service territories. We then collected the local average electricity and gas prices for each service territory in the state. These weather and price data are the same primary data

series used by the RECS and included with each household in the survey. We then determine each household's utility and climate zone by matching the household's information in the RECS with the known average price and weather data for each utility and NWS station in California.

The remaining information necessary to determine a household's specific rate schedule (namely, the household's income and its home heating system) are directly available in the survey. We also used the RECS's electricity expenditure data to determine which eligible low-income households are actually participating in their utilities' low-income electricity tariff programmes. To complete the procedure, we manually compiled the complete 1993 and 1997 electricity tariff books for each California utility, from filings archived at the California Public Utilities Commission public records library and direct contact with municipal utilities' tariff departments. In the end, the 1307 California households in the RECS sample were matched to 189 distinct rate schedules.

Table 1 provides some information on how well this matching procedure performs. As the survey is a stratified probability sample of California households, we expect (and find) reasonable agreement between what the utilities report as their number of residential accounts and the number of households implied by the survey. For the five largest utilities (which serve 93% of California households), the implied geographic distribution of RECS households by utility is quite close to that reported in the utilities' regulatory accounting data. The most notable deviations occur for the two smallest investor-owned utilities, Sierra Pacific and PacifiCorp, which serve sparsely populated mountainous northern and eastern areas of the state. We believe that the stratification design and a special segment of the RECS that oversamples low-income households may account for their overrepresentation.[20]

5.2. *Appliance demand specifications*

Our monthly appliance demand specifications are based on prior empirical research that has studied households' appliance use decisions. Principal sources are the EPRI/REEPS model described in LBL (1995) and the EIA Residential End-Use Model, EIA (1995). We model end-use electricity demand using eight distinct appliance categories: (1) baseline electricity use; (2) electric space heating; (3) central air conditioning; (4) room air conditioning; (5) electric water heating; (6) swimming pools; (7) additional refrigerators and freezers; and (8) other appliances. The baseline category accounts for the electricity consumption of appliances that are universally owned, such as the (first) refrigerator and lights. This category also implicitly includes consumption attributable to any unspecified electrical appliances below the resolution of the RECS survey (such as electric clocks, irons, hair dryers, and the like). Appliance categories two through six are energy-intensive end uses that previous research indicates exhibit some utilization price elasticity (EPRI, 1989). The final category includes less energy-intensive household appliances. A description of all appliances entering the model is provided in Table A1.

Different factors influence appliance-level electricity demand in each category. In particular, we estimate separate price and income effects for each of the first six categories. The remaining appliances are assumed to have a common price effect, as previous studies indicate most of these (refrigeration, cooking, clothes dryers, etc.) exhibit no significant electricity price elasticity. Demographic and other explanatory variables entering the model are defined in Table A2. Demographic characteristics of households are assumed constant during the survey year; the

20. We are grateful to U.S. Energy Information Administration analysts for lengthy discussions on these RECS sampling issues. One unresolved issue is the RECS sampling weights imply 350,000 more California households with electricity service than comparable figures in California utilities' regulatory accounting data (this is evident in the bottom line of Table 1). In addition, the survey's cluster sampling procedure will generally yield uneven coverage of smaller utility service areas.

TABLE 1

Average price and number of households for California electric utilities

	Average residential rate in 1993[a] (cents per kWh)	*Number of households*		*Per cent of households*	
		Actual[a]	Estimate[b]	Actual[a]	Estimate[b]
Investor-owned utilities					
Pacific Gas & Elec.	12·25	3,748,831	4,069,268	34·8	36·6
Southern Calif. Edison	12·10	3,636,295	3,655,184	33·8	32·9
San Diego Gas & Elec.	10·81	1,005,257	1,020,010	9·3	9·2
PacifiCorp (Calif.)	6·94	31,872	351,053	0·3	3·2
Sierra Pacific Pwr. (Calif.)	8·79	36,581	169,317	0·3	1·5
Investor-owned subtotal		8,458,836	9,264,832	78·5	83·3
Municipal/public utilities					
Los Angeles	9·85	1,168,229	1,169,431	10·8	10·5
Sacramento	7·65	416,364	377,054	3·9	3·4
Riverside	10·57	80,828	35,510	0·8	0·3
Imperial	8·36	67,021	7592	0·6	0·1
Santa Clara	7·30	38,129	126,735	0·4	1·1
Lompoc	9·21	12,729	61,569	0·1	0·6
Plumas-Sierra	7·70	4674	82,557	0·0	0·7
Subtotal		1,787,974	1,860,448	16·6	16·7
Other municipal/public utilities[c]		526,480	0	4·9	0·0
State total		10,773,290	11,125,280	100·0	100·0

[a]Sources: U.S. Dept. of Energy Form EIA-861 (1993), FERC Form 1 (1993).
[b]Estimate based on the 1993 RECS survey data (see text).
[c]Households served by other small municipalities, rural electric cooperatives, and public power districts.

monthly varying covariates in our specifications are the price schedules and the weather data.[21] All monetary variables are normalized to real (June 1993) prices, using the CPI-U series for California's three consolidated metropolitan statistical areas.

6. RESULTS AND IMPLICATIONS

6.1. Estimates and marginal effects

Table 2 presents the model's estimated marginal effects for the principal variables of interest. Table entries show the effect of a one unit increase in each explanatory factor on monthly kilowatt-hour consumption of each specified appliance. We compute marginal effects separately for each household (using the gradient of its conditional expectation function (6)), and then average across households using the RECS sampling weights. These are interpretable as the mean marginal effects in the population, conditional on ownership of the indicated appliance. Raw demand parameter estimates are reported in Table A3. The fitted model has a mean square error of $(2352\ \text{kWh/year})^2$, which is approximately one-third of the sample variance of consumption.[22]

21. In addition to the specifications evident in Table A3, we imposed a constraint that electricity consumption for space heating and cooling is zero during the summer and winter months, respectively. To accommodate the varied heating and cooling season lengths for different regions and elevations in California, this was implemented via a minimum (one per day) degree-day threshold for the use of these appliances.

22. Hansen's over-identification test statistic is 76·9, which under simple random sampling has $p = 0{\cdot}05$ (df = 58) asymptotically. The RECS is not based on simple random sampling, however. Its multi-stage sampling design implies the actual critical value of this test statistic will be larger (possibly much larger) than its nominal counterpart. We take an alternative formal approach to testing model fit in Section 7, using standard errors adjusted by the survey's design

TABLE 2

Estimated marginal effects (asymptotic standard errors in parentheses)

Explanatory variable	*Effect on kWh consumed per month for:* [a]					
	Baseline use	*Elec. space heating* [b]	*Central air cond.* [c]	*Room air cond.* [c]	*Elec. water heating*	*Swimming pool*
Price (cents/kWh)	0·4	−37·8	−22·5	−63·4	−34·0	−27·5
	(3·7)	(14·8)	(21·3)	(31·1)	(9·5)	(18·4)
Income ('000 $)	0·4	16·2	9·1	21·6	−32·8	6·3
	(2·3)	(13·0)	(10·6)	(20·8)	(7·5)	(9·8)
No. of members	18·0	−7·9	−38·6	−52·1	47·5	
	(3·3)	(20·3)	(16·3)	(19·9)	(10·6)	
No. of rooms	12·9	20·4	9·8	29·2	−35·3	
	(4·5)	(22·0)	(17·4)	(23·4)	(15·2)	
No. of bathrooms	27·0				119·0	
	(9·8)				(40·1)	
Heating deg.-days ('00 °F, base 60)	−10·6	43·3				
	(6·3)	(21·9)				
Cooling deg.-days ('00 °F, base 70)	−59·5		233·0	45·1		
	(22·5)		(57·0)	(123·0)		
Dummy variables						
Apt. building	−48·4					
	(14·1)					
Housing project	−78·9					
	(24·6)					
At home during day	15·8					
	(10·0)					
Urban location	−35·5					
	(11·9)					
Rural location	31·4					
	(25·1)					
	(Effects of additional appliances are shown in Table A4)					

[a] Estimated change in monthly appliance electricity consumption associated with a unit increase in the explanatory variable, *ceteris paribus*. The marginal effects shown are estimated population means, conditional on appliance ownership.
[b] Heating-season months only.
[c] Cooling-season months only.

The signs and magnitudes of the estimates in Table 2 generally agree with prior studies, although there are a few exceptions.[23] The estimated price effects vary substantially across appliances. The smallest effect is associated with baseline use, and is effectively zero. All other appliance price sensitivities are of considerable practical significance. For example, the −27·5 estimate for price and swimming pools in Table 2 implies that a one cent per kilowatt-hour (kWh) increase in the marginal price would reduce a household's annual utilization of pool pumps and motors by approximately 330 kWh per year, which is 15% of a pool's typical electricity use. The

efficiency ratios to account for its complex sampling design.

23. For example, the negative coefficients on income and on the number of rooms in the water heating specification. We suspect this may be due to confounding from unobserved variation in water heater energy efficiency, which is likely to be considerably higher in newer (larger) homes in California. The negative coefficients on the number of household members and space cooling are also of unexpected sign, and may be attributable to an omitted (positive) influence of householder age on space cooling demand.

TABLE 3

Price and income elasticities for California households

Mean elasticities of electricity demand[a]	*Price*		*Income*	
	GMM method	OLS method	GMM method	OLS method
All households	−0·39	+0·16	−0·00	+0·00
Households with:				
Electric space heating	−1·02	−0·46	−0·00	+0·01
No electric space heating	−0·20	+0·35	−0·00	−0·00
Central or room air conditioning	−0·64	+0·05	+0·02	+0·02
No air conditioning	−0·20	+0·24	−0·01	−0·01
No electric space heating nor air conditioning	−0·08	+0·39	−0·01	−0·01

[a] Annual elasticities (see text and Appendix B).

price effects for major appliances providing space heating, cooling, and water heating services differ from one another considerably, both in absolute terms and relative to typical consumption for each appliance (see Table A4).

By contrast, the income effects are mostly statistically insignificant and negligible as a practical matter. This is not entirely surprising, given that our analysis is conditional on households' appliance stocks. To the extent that income affects electricity consumption, it is evidently manifest through households' choices of appliances rather than through utilization behaviour. These results are consistent with prior studies' findings of low-to-negligible appliance utilization income elasticities at the household level (*e.g.* Parti and Parti (1980) and Dubin and McFadden (1984)).

Details on specific appliance-level consumption estimates are provided in Appendix A and Table A4.

6.2. *Price elasticities*

Table 3 presents estimated average annual household price and income elasticities. These elasticity estimates correspond to the percentage change in a household's annual electricity consumption resulting from a 1% increase in the marginal price (or household income) in each month of the year, holding the appliance stock fixed. We calculate demand elasticities separately for each of the 1307 households in the sample, and then average using the survey sampling weights. The elasticities shown in Table 3 are estimated population means for California households.

Before interpreting these numbers, it is important to note that with nonlinear tariffs there is more than one "price" involved in measuring the elasticity of demand. For example, one can calculate the elasticity of demand with respect to an increase in the intercept of the price schedule, with respect to the price of a specific tariff tier, or with respect to the consumer's marginal price. We present elasticity estimates based on the third of these interpretations, so as to reflect households' demand sensitivity on the margin. In doing so we recognize the fact that with multi-part tariffs, changing a consumer's marginal price may alter consumption within the current tariff segment or induce a discrete jump to a different price tier. Our elasticity calculations explicitly account for this possibility, using methods described in Appendix B.

We estimate the mean annual electricity price elasticity for California households to be −0·39. Previous studies of residential electricity demand data have estimated widely varying utilization price elasticities, ranging from nearly zero to about −0·6. These estimates reflect differences in the geographic regions examined, as well as considerable variation in data quality and statistical techniques. Studies conducted by electric utilities, which often have higher-quality data, tend to obtain price elasticities within a narrower range of −0·15 to −0·35 (EPRI, 1989). Our results with the California RECS data fall at this set's upper end, but are close to the −0·35 estimate contained in a much earlier Rand Corporation study of Los Angeles-area households by Acton, Mitchell and Mowill (1976).

It is useful to compare our estimates to those using more traditional estimation methods. The second column in Table 3 shows the elasticities obtained if we ignore the simultaneity of price and quantity under nonlinear pricing and simply perform OLS using the household's average price. The resulting mean price elasticity estimate is +0·16, which has the wrong sign. Such large biases are typical when simultaneity is ignored in electricity demand studies, for the simple reason that there is wide (cross-sectional) variation in demand but relatively limited variation in the price schedules. OLS techniques using the consumer's average or marginal price therefore tend (in essence) to fit the average slope of the price schedule. Similar biases are noted in Dubin (1985) and Maddock *et al.* (1992).

Additional regressions that use other summary price measures appearing in the literature (*e.g.* the midpoint of the two tiers or utility-level average prices) yield elasticity estimates of the correct sign, but much smaller in magnitude than the GMM results using the complete rate schedule. For example, estimates obtained using OLS with the (statistically exogenous) utility-level average price measure in the RECS yield a mean household price elasticity of −0·28.[24] This estimate is consistent with the bias toward zero that one would expect due to this proxy's mis-measurement of the consumer's actual marginal price. It also suggests an explanation for why our GMM estimates imply somewhat more price-elastic behaviour than many earlier studies' (particularly the utility-conducted studies noted above), in that most prior work treats tariff structure information in either an *ad hoc* manner or not at all.

Heterogeneity in price sensitivity. The disaggregate data also reveal considerable and meaningful heterogeneity in households' price and income elasticities. As noted previously, the model permits households' price and income elasticities to vary across households not just with their consumption level, but also with their appliance holdings. Table 3 illustrates the marked differences in demand elasticities for households with different heating and cooling systems. Households with electric space heating or air conditioning exhibit a much higher electricity price elasticity than households without such systems. Households that do not use electricity for either of these purposes have an estimated mean price elasticity very close to zero. This heterogeneity is consistent with the limited prior evidence on electricity price elasticity variation across households (*e.g.* Dubin, 1985). As a practical matter, it suggests that there are effectively two "types" of households with respect to electricity demand behaviour: those who use electricity for space heating or air conditioning and exhibit some electricity price elasticity, and those who do not and are price insensitive.

Further information about the heterogeneity in households' demand elasticities is provided in Figure 2. This histogram of the sample households' price elasticities is constructed (using the survey weights) to represent the distribution for the California population. The point-mass at zero

24. Price elasticity differences of seemingly small amounts (*e.g.* −0·28 vs. −0·39) are economically quite important in electricity markets. Assuming residential demand is too inelastic by this difference of −0·1 when increasing the marginal rate by (say) three cents per kWh would overestimate annual revenue for California's larger utilities by approximately 75 million dollars.

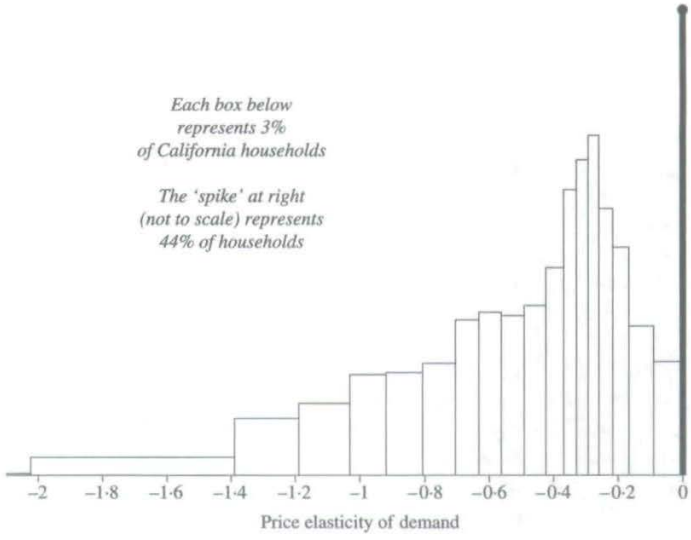


FIGURE 2
Estimated distribution of California households' electricity price elasticities

indicates that 44% of California households exhibit no short-run demand sensitivity to changes in the marginal price of electricity. This segment of the population is primarily households that own no major electric appliances other than a refrigerator, and whose minor appliances fall within the inelastic "baseline use" category of the model. The expected fraction of households whose demand curves cross their price schedules in the "gap" between the two price tiers is 1–2% each month. Thus, very few households have a locally zero estimated price elasticity due only to the discontinuity in the price schedule.

The striking feature of Figure 2 is its highly asymmetric, negatively skewed shape. This pattern indicates that most households will alter their electricity consumption very little in response to a price change. A small fraction of households, however, are actually elastic demanders (roughly 1 in every 8 families) and would react with large changes in their electricity use. This has noteworthy implications for the welfare effects of electricity price changes, inasmuch as most of the dead-weight welfare losses from a price increase would evidently be borne by a fairly small share of the consumer population.

Where a household is located in this distribution is related to its income and other demographic characteristics. Table 4 summarizes household electricity price elasticities by income and consumption levels. How price elasticities vary with household income (in the cross section) is of interest because regulatory commissions provide subsidized tariffs to low-income households, and are at times concerned with the consumption incentives of these subsidies. The conventional wisdom is that households with lower incomes are more sensitive to energy prices than households with medium-to-high incomes. The results in the top half of Table 4 are consistent with this view, although the magnitudes of these differences are not dramatic.

The lower half of Table 4 indicates how household price elasticities vary with the amount of electricity the household consumes. This relationship is of interest because the aggregate consumption and revenue effects of a tariff change depend upon how elasticities vary across the different tiers of the price schedule. Somewhat surprisingly, we find that elasticities are lower

TABLE 4

Price elasticities by household income and electricity consumption

Quartile	Quartile range	*Price elasticity*[a] GMM method	OLS method
By household annual income level:[b]			
1-st	Less than $18,000	−0·49	+0·15
2-nd	$18,000 to $37,000	−0·34	+0·17
3-rd	$37,000 to $60,000	−0·37	+0·14
4-th	More than $60,000	−0·29	+0·17
By household annual electricity consumption:			
1-st	Less than 4450 kWh	−0·46	+0·37
2-nd	4450 to 6580 kWh	−0·35	+0·04
3-rd	6580 to 9700 kWh	−0·32	−0·00
4-th	More than 9700 kWh	−0·33	−0·08

[a] Mean annual electricity price elasticity for households within each quartile.
[b] Approximate California household income quartiles, in 1998 dollars.

for households that use high amounts of electricity, despite the fact that households with energy-intensive electric space heating/cooling systems have much greater electricity price sensitivity *ceteris paribus*. This inverse relationship reflects both a weak correlation between household income and ownership of electric space heating/cooling systems, and the fact that households tend to substitute toward more price-inelastic electricity uses as income rises. Thus, from an economic efficiency standpoint, the welfare cost of raising a given amount of revenue will be minimized if the marginal price changes are disproportionately larger for the highest-demand consumers.

Further results along these lines using different data are examined in Reiss and White (2003).

7. VALIDATION: THE 1998 PRICE CHANGES

Our empirical results rest in part on the appliance demand specifications and error distribution assumptions of the model. Because we must aggregate over appliances and over time to match the consumption level of the data, these appliance demand specifications are not testable directly. In this section we examine the model's validity using both within- and out-of-sample tests.

7.1. Within-sample fit

For purposes of interpreting the out-of-sample test below, it is useful to first examine the representativeness of the RECS consumption data and in-sample model predictions. Because electric utilities are subject to extensive regulatory reporting requirements, there exist comprehensive aggregate data on utilities' actual sales and number of customers. In principle, averages from these data will differ from their counterparts for the RECS households by amounts attributable to the survey's sampling error.

Some evidence on this issue is provided in Table 5. The first numerical column in Table 5 presents actual electricity consumption per household for California and its four largest utilities. The second column presents the corresponding mean electricity consumption for the RECS

TABLE 5

Within-sample predicted and actual consumption

Electricity consumption per household, in kWh	Actual[a]	Sample data: Sample mean	Sample data: Standard error[b]	Sample data: Actual error	Estimated model: Predicted mean	Estimated model: Average within-sample error
Pacific Gas & Elec.	6531	5796	258	+735	5899	+103
Southern Calif. Edison	6238	6063	291	+175	5961	−102
San Diego Gas & Elec.	5706	4627	514	+1079	4775	+148
Los Angeles Wtr. & Power	5261	5113	454	+148	4867	−246
All California	6355	6007	157	+348	6010	+3

[a] Weighted average of the total residential sales (in kWh) divided by the number of residential accounts in each of 1993 and 1997, as reported by each utility. Source: U.S. Dept. of Energy Form EIA-861 (1993, 1997).
[b] Standards errors shown account for the multi-stage sample design of the RECS (see EIA, 1994).

sample households along with the standard error of the survey. For the state as a whole, Table 5 implies that the RECS sample under-represents actual household electricity consumption by slightly more than two standard errors. We also find that the RECS data understate average household consumption for each of the state's four largest utilities, although by sometimes less than two standard errors.[25]

The final columns compare the model's predictions to these actual and sample consumption averages. Since the model is fitted to the RECS data, the difference between the observed and predicted averages represents within-sample error. Although our model is nonlinear, the average within-sample error for the full sample is essentially zero. As with the raw sample data, however, the estimated model under-predicts actual consumption for each utility and the state overall. This is not entirely surprising, given that the model can at best capture the behaviour of the sample to which it is fitted. We conclude that while the RECS sample appears to understate actual household consumption in California, the model does reasonably well (*i.e.* within a few per cent) at fitting the sample data for each utility.

7.2. *Out-of-sample tests*

In January 1998, shortly after the end of our sample data, California's three largest investor-owned utilities reduced the price of residential electric service by 10%. This price change, by virtue of its magnitude and exogeneity to the household, provides a unique opportunity to evaluate the model's out-of-sample accuracy. We also account for the El Niño Pacific weather disturbance that occurred in 1998 and 1999, which changed California's weather patterns substantially.

Ideally, we would prefer to evaluate the model using within-household differences in predicted and actual consumption between 1997 and 1998 (*i.e.* a matched-pair test). Unfortunately, due to the triennial (and non-longitudinal) nature of the RECS, we do not have data on actual consumption after 1997 for the sample households. Instead, we base inference on

25. There are other reasons why the *utility-specific* averages might differ between the RECS and the actual (regulatory accounting) data. First, while the RECS is designed to generate a representative sample of households at the state level, the sampling scheme is not designed to produce representative samples within each utility's service territory. Second, the household-utility matching procedure we use to obtain rate schedules (in Section 5) introduces potential misclassification error. The difference in state-level average consumption between the RECS and the regulatory accounting data is not subject to these caveats, however.

TABLE 6

Out-of-sample prediction tests for 1998 and 1999

Utility electricity sales per household, in kWh	Actual[a]	Predicted	Difference	Std. error	Prob.[b]
		Panel A: 1998			
Pacific Gas & Elec.	6775	6198	+578	252	0·02
Southern Calif. Edison	6455	6233	+223	280	0·43
San Diego Gas & Elec.	5935	5005	+930	580	0·11
Los Angeles Wtr. & Power	5438	4885	+554	498	0·27
		Panel B: 1999			
Pacific Gas & Elec.	6905	6187	+718	267	0·01
Southern Calif. Edison	6423	6257	+136	292	0·64
San Diego Gas & Elec.	5964	5078	+886	647	0·17
Los Angeles Wtr. & Power	4866	4826	+40	496	0·94

[a]Total residential sales (in kWh) divided by the number of residential accounts, as reported by each utility. Source: U.S. Dept. of Energy Form EIA-861 (1998, 1999).

[b]Approximate probability of a difference between actual and predicted at least as large (in magnitude) as observed, under the model.

comparisons to the average household consumption reported in California utilities' regulatory accounting data for 1998 and 1999.

To implement a formal test we first extended the actual weather series used in the model through 1998 and 1999. We also collected the exact form of the tariff changes implemented in 1998 and 1999 for each RECS household.[26] We then use the model to predict what the RECS households would have done in 1998 and 1999, given the price change and weather conditions that occurred, and aggregate these responses to the utility level.

Table 6 compares these out-of-sample predictions to actual residential electricity consumption for California's four largest utilities in 1998 and 1999. The second-to-last column provides estimated standard errors for the difference between the actual and predicted consumption averages. These standard errors account for both the non-sampling variance in future consumption outcomes under the model, and the sampling error associated with the RECS multi-stage design.[27] The final column reports the (two-sided) probability of observing a difference at least as large as that shown, under the maintained assumptions of the model. Small p-values constitute evidence against the validity of the model.

As the within-sample results foreshadowed, the model continues to under-predict average consumption in 1998 and 1999. For three of the four utilities in each panel, however, the observed differences from the model's predictions are within the bounds of what may be ascribed to chance by conventional standards of statistical significance. The smallest p-values, for Pacific Gas and Electric in 1998 and 1999, are attributable to the particularly acute under-representativeness (relative to sampling error) of the RECS households' consumption data for

26. The January 1998 price decrease amounted to lowering each tier of the household's price schedule by 10%. The actual marginal price change thus depends upon the household's particular rate schedule. There was also a separate price increase for households served by the Los Angeles Department of Water and Power in 1999, which shows up as a notable decline in consumption for Los Angeles households between 1998 and 1999.

27. Since we have a nonlinear model and the RECS uses a multi-stage sampling design, the standard errors for this test are approximate. We use a linear approximation (delta) method to estimate the variance of average predicted consumption under simple $(1/n)$ random sampling, and then inflate the result by the design efficiency ratio of the RECS consumption series (about 1·4) to get the standard errors in Table 6. This method and related techniques are discussed in Skinner, Holt and Smith (1989).

this utility. Interestingly, for three of the four utilities in each panel, the model's average error (relative to actual) is smaller for the out-of-sample years of 1998 and 1999 than it is for the within-sample years reported in Table 5. On that basis, the model appears to deliver reasonable predictions for how California households respond to electricity price changes.

8. ANALYSING PROSPECTIVE TARIFF DESIGNS

An important feature of the model developed above is that it can be used to evaluate, on a prospective basis, the effects of complex price schedule changes. For a variety of practical reasons, regulatory agencies are often reluctant to authorize randomized-assignment pricing experiments as a means to evaluate major tariff changes. Thus, counter-factual simulations based on econometric models become the analytic method of choice. The accuracy of these simulations is a matter of considerable practical interest, inasmuch as tariff changes for electricity can affect billions of dollars in consumer expenditures.

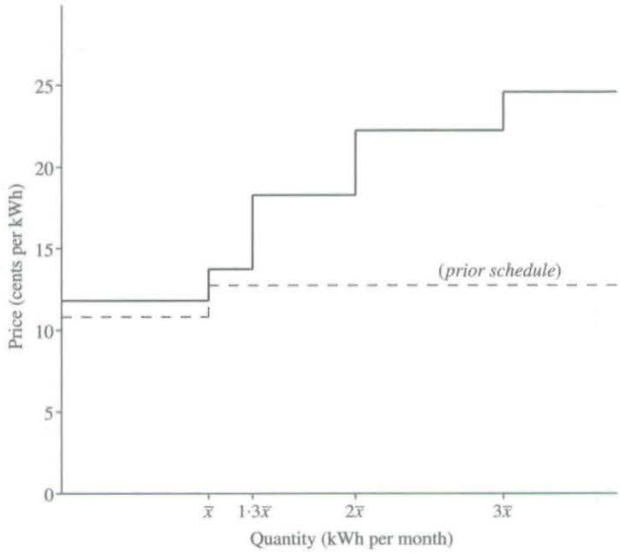
In this section, we provide consumption and expenditure estimates for a complex tariff design being implemented in California. Following a financial crisis facing that state's utilities in the spring of 2001, the California Public Utilities Commission approved new tariff structures for the state's two largest utilities. The new multi-part tariff structure for residential electric service is shown graphically in Figure 3. Under this five-tier design, the household inherits from its prior (two-tier) tariff a monthly reference quantity, $\bar{x}$. The first $\bar{x}$ kilowatt-hours of monthly electricity consumption are then billed at one price per kilowatt-hour, the next $30\% \times \bar{x}$ are billed at a higher price, and so forth as indicated in Figure 3. The reference quantity $\bar{x}$ and the specific tier prices vary based on the utility, the season, the household's climate zone and home heating system, and other factors.

This novel pricing system is intended to achieve several objectives. First and foremost is to raise additional revenue for the state's utilities. Second, the new tariff is intended to promote energy conservation, particularly among higher-demand consumers. Third, there is a distributive objective underlying this tariff design. Electricity is a necessary good (in the sense that its budget share declines as household income rises), so a uniform increase in the price of electricity can be quite regressive. By raising marginal prices more for higher levels of consumption, regulatory authorities hope to attenuate this regressivity and minimize expenditure changes for lower-income households.

Because the five-part tariff is unprecedented in historical consumption data, there is no way to extrapolate how well this new system would achieve these objectives using descriptive (*i.e.* reduced-form) econometric methods. Rather, predicting aggregate demand requires explicitly modelling consumer choice behaviour under the new tariffs. To do so, suppose j indexes the five tiers in Figure 3, p_j is the marginal price on tier j, and $\bar{x}_j$ is the j-th-tier upper boundary. Set $x_j = x(p_j, y_j, z, \varepsilon; \beta)$, where y_j denotes the household's income plus the cumulative infra-marginal price discount applicable in tier j. Conditional on observable household characteristics, the expected value of monthly household consumption is then

$$E(x^* \mid \cdot) = \sum_{j=1}^{5} P_\varepsilon(\bar{x}_{j-1} < x_j < \bar{x}_j) \cdot E_\varepsilon(x_j \mid \bar{x}_{j-1} < x_j < \bar{x}_j) + \sum_{j=1}^{4} P(x_{j+1} < \bar{x}_j < x_j) \cdot \bar{x}_j \tag{12}$$

using the conventions $\bar{x}_0 = 0$, $\bar{x}_5 = \infty$, and P_ε the distribution of ε given the observables. The first sum is the contribution to expected consumption conditional on demand crossing the price schedule on one of the five steps, and the second sum is the contribution conditional on demand crossing the price schedule in one of the "gaps" between the steps. As before, this



Notes: The reference quantity, $\bar{x}$, varies across households and seasons. The rates depicted above are for the most common residential tariff schedule for this utility. The prior schedule shown applied from 1998 through 2000.

Source: Southern California Edison PUC Advice Letter 1545E, Schedule D, Tariff Sheet 29197E (2001).

FIGURE 3

A five-tier price schedule Southern California Edison, Residential Electric Service

amounts to a probability-weighted average of expected demand within each segment of the new tariff schedule. Stated in behavioural terms, the consumer sorting-on-the-unobservables problem that occurs with multi-part tariffs must be addressed not only in demand estimation, but also when predicting consumption at new prices.[28] Such nonlinearities are why the aggregate impacts of a new tariff design depend, sometimes delicately, upon the heterogeneity in consumers' price elasticities across the population.

We use equation (12) and the estimated demand model to evaluate a five-tier tariff system adopted by the California Public Utilities Commission in May 2001. With little prior analysis, this system was implemented the following month for approximately 7·8 million households served by the Pacific Gas and Electric Company and the Southern California Edison Company. We use these utilities' tariff books to identify the terms of the new tariff applicable to each household in the RECS sample. We also evaluate these tariff changes for "normal" weather conditions, using 30-year average degree-days from the NWS station located nearest each household. The tier selection probabilities in (12), which depend upon both the household and its particular tariff schedule, are evaluated using the normality assumption and household-specific variance estimate from the econometric model. We evaluate the expected consumption equation

28. In particular, equation (12) differs from what one obtains by simply intersecting the household's estimated demand curve (assuming ε to be zero) and the new price schedule. That technique implicitly treats the tariff segment selection probabilities in (12) as either zero or one, and ignores the conditional expectation adjustment for ε in each tariff segment. Unless the variance in the household's future consumption (given the observables) is in fact zero—a highly unlikely circumstance—such a technique will systematically misestimate consumption under a new price schedule.

TABLE 7

Household consumption and expenditure changes with five-tier tariff schedules (all monetary amounts in constant 1998 dollars)

Means per household[a]	All households	By income quartile[b] 1-st	2-nd	3-rd	4-th
Consumption (kWh/year)					
With 2 tiers (1998)	6196	5524	6299	6330	7455
With 5 tiers	5578	4987	5677	5519	6637
Change (%)	−10·0	−9·7	−9·9	−9·7	−11·0
Expenditures ($/year)					
With 2 tiers (1998)	718	633	734	734	873
With 5 tiers	897	770	921	925	1120
Change (%)	24·8	21·6	25·4	25·9	28·3

[a]Estimated population means for the 7·8 million California households served by the Pacific Gas and Electric Corporation or the Southern California Edison Company. For calculation methods, see text.
[b]For income quartile breakpoints, see Table 4.

separately for each of the 1307 households in the RECS sample, and average these predictions using the survey sampling weights. A similar formula and procedure is used to estimate each household's (expected) expenditures under the new tariff.[29]

Table 7 provides estimates of average household electricity consumption and expenditures under the new five-tier tariffs. For comparison, we also show the values obtained using the prior two-tier tariff schedules in effect from 1998 through 2000. The first numerical column presents estimated population means for all the 7·8 million affected households. The results indicate their average (and aggregate) annual electricity consumption would be approximately 10% lower under the new five-tier tariff system than under the preceding tariffs over a normal weather year. The corresponding increase in annual household electricity expenditures is approximately 25%, or $179 per household (in 1998 dollars). To put this in some perspective, $179 is 8% of the average 1998 state personal income tax liability per household in California.

Our expenditure results are considerably lower than the official estimates of the California Public Utilities Commission. That agency predicted the increase in the two affected utilities' total residential electric revenues would be approximately $1·8 billion annually, or $228 per household. The difference between these two estimates can be explained largely by differences in the treatment of demand elasticities. In particular, the Commission uses a "static scoring" method for predicting the revenue change associated with a new rate schedule design. This amounts to assuming that each consumer's annual demand is completely price-inelastic, so that expenditure changes can be predicted by applying the old and new tariff schedules to the same consumption data. Inasmuch as consumers do exhibit some demand elasticity, this method overestimates revenue associated with the higher tariff structure.

Since the model we employ is estimated with survey data, we have information on individual households' income levels that can be used to examine the distributional consequences of tariff changes. This issue has not been examined quantitatively in the state regulatory agency's tariff

29. Note that approximately 10% of households participate in a low-income tariff programme that is exempt from the new tariff designs. These households appear in our sample, and our predictions for them use their (unchanged) tariffs. The predictions do not account for changes in an eligible non-participating household's incentive to apply for this programme, however.

models, as their analyses rely upon utilities' billing data that do not include income information. The additional columns in Table 7 report the model's predictions for average consumption and expenditures by household income quartile. Not surprisingly, under either tariff electricity consumption and electricity expenditures increase with household income. What is interesting to note, however, is that in percentage terms the change in household electricity consumption between the new and old tariff systems is nearly constant across income quartiles. That is, the larger marginal price increases paid by households consuming higher quantities more or less exactly offsets the increasingly inelastic demand behaviour of households with higher incomes (see again Table 4).

A similar phenomenon is evident in the estimated expenditures. In absolute terms, however, the increase in expenditures across income quantiles does not rise nearly as fast as income. This implies, and can be verified directly in the unsummarized data, that the new tariff is (slightly) more regressive than the system it replaces. It is, however, considerably less regressive than a revenue-equivalent traditional uniform rate increase, whose distributional impacts California policy-makers have sought to avoid.

9. CONCLUDING REMARKS

The practical motivation for this paper arose from an acrimonious—and, we believe, poorly informed—debate over the consequences of major electricity price changes in California. Our objective is not to impugn the decisions ultimately made and examined here, however; rather, it is to show how more sophisticated empirical methods, in conjunction with detailed micro-survey data now available, can be productively harnessed to resolve *ex ante* the policy-making uncertainties that fuel such debates.

It is worth noting that substantively similar methodological issues arise in a variety of other markets. Regulatory pricing of local telephone service (a perennially controversial matter) and residential water use are leading examples. In those markets nonlinear pricing is quite common, and formal demand analysis is a largely accepted part of the price-setting process. The econometric issues addressed in this paper would appear particularly germane to those contexts. In a substantively different setting, there are close parallels between the analytic methods used here and the micro-simulation procedures commonly used to evaluate tax code changes. Specifically, the methodological aspects of implementing "dynamic" vs. "static" scoring techniques for tax revenue changes are precisely analogous to the modelling of consumers' demand elasticities in the tariff design analysis presented here.

Last, an interesting and useful extension of this research is the normative empirical analysis of nonlinear tariff designs. The methods employed above would appear to lend themselves readily to development of more economically efficient tariffs. For example, if the new five-part tariffs in California are efficient (by almost any criterion), it is by fortuity rather than by design. Despite a great deal of work in the theoretical literature on efficient nonlinear pricing schemes, there are as yet few (if any) detailed empirical studies. We leave this interesting issue a matter for future research.

APPENDIX A. APPLIANCE-LEVEL SPECIFICATIONS

A.1. Specification and parameters

A complete list of the variables entering the demand model is shown in Tables A1 and A2. The complete set of coefficient estimates are listed in Table A3. This table is organized so that each column contains the parameter estimates associated with an appliance category's electricity demand. These raw parameters are used to obtain the marginal effects in Table 2, as described in Section 6.

TABLE A1

Appliances entering electricity demand model

Mnemonic	*Appliance*	*Description*
	Primary electric space heating	1 if household has permanently installed electric space heating (electric furnace, heat pump(s), or wall resistance units)
	Central air cond.	1 if household has a central air conditioning unit
	Room air cond.	1 if household has room window/wall air conditioning units
	Electric water heat.	1 if household has an electric water heater
ELECCOOK	Electric cooking	1 if household has an electric oven and/or stove
ELECDRYR	Electric dryer	1 if household has an electric clothes dryer
FREEZER1	Separate freezer	1 if household has a separate (stand-alone) freezer
FREEZER2	Second freezer	1 if household has two (stand-alone) freezers
FRIDGE2	Second refrigerator	1 if household has a second refrigerator
CLTHWASH	Clothes washer	1 if household has an automatic clothes washer
DISHWASH	Dishwasher	1 if household has an automatic dishwasher
PORTHEAT	Portable space heat	1 if household has one or more portable electric space heaters
HOTTUB	Hot tub	1 if household has a hot tub with electric heating
POOL	Swimming pool	1 if household has a swimming pool
H2OBEDHT	Waterbed heating	1 if household has a waterbed with electric heating
MICROWV	Microwave	1 if household has a microwave oven
NTV	Number of TVs	Number of televisions in household

TABLE A2

Additional explanatory variables entering demand model

Mnemonic	*Variable*	*Description*
PRICE	Electricity price	Monthly electricity price, in 1993 cents per kilowatt-hour
INCOME	Household income	Average monthly household income, in thousand 1993 dollars
HDD	Heating degree-days	Monthly heating degree-days base 60 °F, in hundreds
CDD	Cooling degree-days	Monthly cooling degree-days base 70 °F, in hundreds
NROOMS	Number of rooms	Number of rooms in home (excluding bathrooms)
NBATHRMS	Number of bathrooms	Number of bathrooms in home
NMEMBERS	Number of members	Number of people in household
FRSIZE	Fridge/freezer size	Size of appliance, in cubic feet
ATHOME	At home	1 if someone is normally at home during the day
HUPROJ	Housing project	1 if household resides in a public housing project
APTBLDG	Apartment building	1 if household resides in an apartment building
RURAL	Rural location	1 if household resides in a rural location
URBAN	Urban location	1 if household resides in an urban location
YEAR97	Survey year 1997	1 if household data from 1997 survey wave

The model also includes 154 variance and covariance parameters (from equation (11)) not reported here. These indicate that the variance of household-level unobservable characteristics increases with appliance holdings, although it depends (in a complicated fashion) on the types of appliances owned by the household. Overall, the heteroscedasticity patterns sensibly reflect the enormous differences in potential energy consumption associated with different appliance portfolios.

A.2. Appliance consumption estimates

A useful feature of the fitted model is that it provides estimates of electricity use for each appliance. These are reported in Table A4. In addition to being of direct interest to energy analysts, these appliance-level consumption estimates provide a useful check on the model since they can be compared to independent estimates.

The first numerical column is the estimated proportion of California households that own particular appliances, based on a weighted average of 1993 and 1997 sample ownership frequencies in the RECS. The second column reports the model's prediction for the average annual electricity consumption of each appliance. These estimates are obtained

TABLE A3

Electricity demand model coefficient estimates—GMM method (asymptotic standard errors in parentheses)

Explanatory variable[a]	Baseline use[b]	Elec. space heating	Central air cond.	Room air cond.	Elec. water heating	Swimming pool	Second refrig.	Separate freezer
CONST	−24·6 (49·9)	379·0 (216·0)	312·0 (276·0)	814·0 (369·0)	467·0 (107·0)	514·0 (229·0)	−23·5 (61·6)	−108·0 (57·9)
PRICE	0·4 (3·8)	−38·2 (15·0)	−23·2 (22·1)	−65·3 (32·5)	−35·3 (9·6)	−28·2 (19·3)		
INCOME	0·4 (2·4)	16·3 (13·1)	9·3 (11·0)	22·3 (21·5)	−34·0 (7·7)	6·4 (10·1)		
NMEMBERS	18·1 (3·4)	−8·0 (20·5)	−39·8 (16·8)	−53·7 (20·5)	49·3 (11·1)			
NROOMS	13·0 (4·5)	20·6 (22·3)	10·1 (17·9)	30·1 (24·1)	−36·6 (15·8)			
NBATHRMS	27·3 (9·9)				123·0 (41·8)			
HDD	−10·7 (6·3)	43·8 (22·1)						
CDD	−60·0 (22·7)		240·0 (58·8)	46·5 (128·)				
FRSIZE	6·5 (1·7)						7·8 (3·7)	9·3 (3·3)
DISHWASH	20·4 (11·5)				11·3 (37·3)			
CLTHWASH	18·8 (14·0)				71·3 (40·9)			
ELECDRYR	66·2 (13·1)							
FREEZER2	178·0 (55·7)							
ELECCOOK	21·5 (11·7)							
MICROWV	32·8 (12·1)							
HOTTUB	109·0 (32·2)							
PORTHEAT	108·0 (21·1)							
H20BEDHT	51·2 (23·7)							
NTVS	40·7 (5·8)							
ATHOME	16·0 (10·1)							
APTBLDG	−48·8 (14·2)							
HUPROJ	−79·6 (24·8)							
RURAL	31·7 (25·3)							
URBAN	−35·8 (12·0)							

Table continues on next page

TABLE A3

Continued

Explanatory variable[a]	Baseline use[b]	Elec. space heating	Central air cond.	Room air cond.	Elec. water heating	Swimming pool	Second refrig.	Separate freezer
YEAR97	2·0 (10·3)							
Model RMSE (kWh/year)	2352·0							

[a]Estimated on 1307 California households in the 1993 and 1997 Residential Energy Consumption Surveys. The dependent variable is electricity consumption, in kWh; parameter estimates are monthly demand coefficients from equation (8).

[b]This category includes all miscellaneous electrical appliances not explicitly modelled such as lights, household electronics, fans, and so forth. The first refrigerator is included in this category because ownership is nearly universal and its effect not separately identifiable from other universally owned appliances such as lights.

TABLE A4

Estimated electricity consumption by household appliance

	Present study		*Prior estimates*[a]	
			Average annual use, in kWh:	
Appliance type	Households with appliance, in per cent[b]	Avg. annual electricity use, in kWh[b]	EIA (1995)[c]	LBL (1997)[c]
Elec. space heating	23·2	1131	1185[b]	2609–3481[d]
Central air cond.	30·3	1270	1283[b]	1306–1446[d]
Room air cond.[e]	13·7	619	n.a.	476[d]
Elec. water heating	15·6	2389	2835	3658
Refrigerator	99·8	1231[f]	1141	1144
Electric cooking	46·0	258	451	822
Separate freezer	16·7	582	1013	1026
Elec. clothes dryer	32·2	795	1090	1000
Clothes washer[g]	64·1	223	n.a.	100
Dishwasher[g]	48·3	241	n.a.	250
Swimming pool	5·6	2227	n.a.	1500[h]
Hot tub	3·5	1288	n.a.	2300
Waterbed heater	5·1	606	n.a.	900
Microwave	83·4	388	n.a.	132
Televisions[e]	98·3	482	n.a.	513

Notes:

[a]Sources: U.S. Energy Information Administration (1995), Table 3.1, and public-use micro files.
Lawrence Berkeley Laboratory (1997), Tables A6 and A7.

[b]Estimates for California households.

[c]Estimates for all U.S. households, except as indicated.

[d]Range of estimates for households in southwestern U.S. states (Calif., Nev., and Ariz.).

[e]Estimates are for all units in household combined.

[f]Estimate based on second refrigerator only.

[g]Excludes energy used to heat water entering washer.

[h]Estimate for pool pump motor only.

n.a. indicates an estimate is not available.

from the fitted appliance demand equations (8), then averaged across households (using the RECS sampling weights) so as to reflect typical values in the population of appliance owners.

The third column in Table A4 contains appliance energy consumption predictions from a model developed by the U.S. Energy Information Administration (EIA, 1995). The final column is from a Lawrence Berkeley Laboratory (LBL, 1997) meta-analysis of numerous residential appliance energy consumption estimates. These estimates are derived from a wide range of direct metering, engineering, and statistical studies of energy use in different areas of the U.S. Overall, there is general agreement between these prior studies and the model's results—perhaps surprisingly so, since the present model is not fit to utilization data for individual appliances. The principal difference occurs with heating, where the LBL survey reports a significantly higher number than we or the EIA do. This can in part be explained by the broader geographic coverage of the LBL analysis and the high sensitivity of heating energy use to climate differences.

APPENDIX B. ELASTICITY CALCULATIONS

This Appendix describes the method used to calculate the elasticity estimates reported in Tables 3 and 4. There are two complications that make calculating elasticity estimates more involved here than in conventional settings. The first is the temporal issue of how to calculate an annual elasticity of demand when the consumer may face varying (and unobserved) marginal prices over the course of the year. The second is the discontinuity problem—because the price schedule is discrete, a change in the consumer's marginal price can move consumption smoothly within a single tariff segment, shift the consumer off or onto the discontinuity between tariff segments, or yield no change in consumption at all.

Addressing the discontinuity problem first, write the optimal consumption for household i in month t using the equilibrium relation from equation (1):

$$x_{it}^* = x(p_{it}^*, y_{it}^*, z_{it}, \varepsilon_{it}),$$

where $y_{it}^* = y_{it} + \bar{x}_{it} \cdot (p_{it}^* - p_{1,it})$. In this equation, p_{it}^* is the household's marginal willingness to pay for the last unit consumed (which may differ from the marginal price, if consumption occurs at the step-point $\bar{x}$ where the price rises from p_1 to p_2). To account for this discontinuous feature when calculating elasticities, we use the following decomposition. Consider an increase in the price of the specific tariff segment in which the household initially consumes. Denoting this initial marginal price as mp, and the consumer's initial marginal willingness to pay as $mwtp$, the total change in consumption can be written as

$$\frac{dx^*}{d(mp)} = \Bigg[\underbrace{\frac{\partial x^*}{\partial(mwtp)}}_{\substack{\text{slope of}\\ \text{demand}}} + \underbrace{\frac{\partial x^*}{\partial y}}_{\substack{\text{marginal}\\ \text{income}\\ \text{effect}}} \cdot \underbrace{\frac{d\,\Delta y}{d(mwtp)}}_{\substack{\text{change in}\\ \text{infra-marginal}\\ \text{expenditure}}} \Bigg] \underbrace{\frac{d(mwtp)}{d(mp)}}_{\substack{\text{0 if at } \bar{x},\\ \text{1 if not}}}$$

where $\Delta y = \bar{x}_{it} \cdot (p_{it}^* - p_{1,it})$ (cf. (3)). The first term in the square brackets is standard. The remaining terms in the bracketed expression yield the (income) effect of changing the infra-marginal price discount. For an optimizing consumer, the term outside the brackets will be zero if consumption occurs at the step-point, $\bar{x}$, and one otherwise.

For the demand specification and two-tier tariff we analyse, this expression takes the simple form:

$$\frac{dx_{it}^*}{d(mp)} = \alpha \cdot \mathbf{1}(x_{it}^* \neq \bar{x}_{it}) + \beta\, \bar{x}_{it} \cdot \mathbf{1}(x_{it}^* > \bar{x}_{it}) \tag{B.1}$$

where $\mathbf{1}(\cdot)$ is the indicator function, and α, β are the price and income coefficients from equation (10). We define a household's monthly price elasticity, η_{it}, in terms of the effect of price on the margin:

$$\eta_{it} = \frac{(mp)_{it}}{x_{it}^*} \cdot \frac{dx_{it}^*}{d(mp)}.$$

A wrinkle arises in computing η_{it}. Since our consumption data are aggregated to an annual level, we do not observe the household's monthly consumption, x_{it}^*, nor its monthly marginal price. Instead, we estimate x_{it}^* with the "plug-in" estimator

$$\hat{x}_{it}^* \equiv E[x_{it}^* \mid w_{it}; \hat{\theta}]$$

using the conditional moment equation derived in (6) evaluated at the estimated parameter values. We then obtain the marginal price estimate, $\widehat{mp}_{it}$, from the household's rate schedule in month t for the quantity $\hat{x}_{it}^*$. Finally, we can compute each household's monthly price elasticity using equation (B.1) as

$$\hat{\eta}_{it} = \frac{\widehat{mp}_{it}}{\hat{x}_{it}^*} \cdot \left[\hat{\alpha}_i \cdot \mathbf{1}(\hat{x}_{it}^* \neq \bar{x}_{it}) + \hat{\beta}_i\, \bar{x}_{it} \cdot \mathbf{1}(\hat{x}_{it}^* > \bar{x}_{it}) \right]$$

where the "hats" indicate estimated quantities.

To obtain the annual price elasticities reported in Tables 3 and 4, we calculate (pointwise) the percentage change in annual electricity consumption for a per cent change in the household's marginal price in *each month* of the year. That is, for each household in the sample we compute

$$\hat{\eta}_i = \frac{1}{x_i} \sum_{t=1}^{12} \hat{\eta}_{it} \cdot \hat{x}_{it}^*$$

where x_i is the household's actual annual electricity consumption. The tables report estimated population means obtained by averaging these household-level annual elasticity estimates using the RECS survey weights.

Income elasticities are obtained similarly, after observing that

$$\frac{dx_{it}^*}{dy} = \beta \cdot \mathbf{1}(x_{it}^* \neq \bar{x}_{it}).$$

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112.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.112.1 Please provide each customer demographic survey other than the Residential End Use Survey (REUS) that has been prepared for residential customers since January 2010. If no survey other than the REUS has been prepared since January 2010, please provide the most recent survey other than the REUS.

RESPONSE:

The REUS typically features sample sizes ranging from 4,000 to 8,000 customer households and is the most representative BC Hydro residential survey for understanding customer demographics. It typically contains ten questions on the demographics of the principle bill payer and household occupants. The most recent REUS, based on data collected in 2014 from approximately 7,500 households, is included in the Application. Please refer to Exhibit B-1, Appendix C-3F, page 1 of 348.

While BC Hydro also conducts residential surveys to collect information on customer experience and satisfaction with individual DSM programs, these surveys tend to be much smaller and less representative than the REUS. They also collect less customer demographic information than the REUS. Given the comprehensiveness and representativeness of the REUS, the 2014 REUS is more helpful in providing an understanding of BC Hydro's customer demographics than any of the individual targeted DSM program related surveys.

113.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.113.1 For BC Hydro's existing residential DSM programs, please provide:

(a) An explanation of how BC Hydro screens DSM projects;
(b) An identification of all potential DSM programs screened for its present DSM Plan;
(c) Any evaluation of the cost-effectiveness of its current DSM programs;
(d) A specification of the avoided cost estimates BC Hydro is using to screen DSM projects. Document the derivation of the avoided costs, including all workpapers and spreadsheets;
(e) The penetration rate estimated for each program together with the basis of that estimate;
(f) An estimate of the utility costs for each of BC Hydro's DSM programs;
(g) The basis of BC Hydro's forecast of energy and peak savings from each of its DSM programs;
(h) BC Hydro's total budget for DSM projects;
(i) An explanation of how BC Hydro determined how much to spend on DSM and what amount of savings to strive for;
(j) An identification of all DSM programs in which BC Hydro has been forced to shut off applications, or wait-list potential participants, due to budget constraints;
(k) An identification of all DSM programs in which BC Hydro could reach additional customers or fund additional cost-effective measures, if the program budgets were increased; and
(l) An identification and explanation of whether the DSM investment per customer is limited in any program. If so, describe those limits and explain why BC Hydro is not willing to make all cost-effective investments in DSM.

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the information sought is not relevant to and cannot aid in the review of the 2015 RDA or the orders sought in respect of it, or for the purposes of the Minister RIB Report Letter.

The requested information is extraordinarily broad in scope; it amounts to a request that BC Hydro provide a *UCA* section 44.2(1)(a) expenditure schedule for all of BC Hydro's Residential DSM programs as part of the RIB Report process. BC Hydro submits that no reasonable reading of Minister RIB Report Letter Questions 4 and 5 can support such a request. As noted in BC Hydro's response to BCOAPO IR 1.102.1, BC Hydro will be submitting a DSM expenditure schedule filing contemporaneously with or as part of the F2017 RRA in February 2016.

114.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.114.1 For the LICO x 130% customer base served by BC Hydro of customers directly paying their own energy bills, provide a distribution of the estimated number of such customers by the following ranges of LICO:

(a) 0 – 25% of LICO;
(b) 26 – 50% of LICO;
(c) 51 – 75% of LICO;
(d) 76 – 100% of LICO; and
(e) 101 – 130% of LICO.

RESPONSE:

This IR concerns BC Hydro's proposals concerning the RIB Report process. BC Hydro respectfully declines to respond to the IR using LICO multiplied by 1.3. As noted in section 5.5.1.3 of Exhibit B-1 and page 4 of BCOAPO's RIB Report submission of October 16, 2015,[1] BCOAPO agrees with BC Hydro that for purposes of the RIB Report, Statistics Canada's LICO should be used to define and identify BC Hydro's low income customers. The use of LICO multiplied by 1.3 would more than double the proportion of BC Hydro's residential customers categorized as low income, from 10 to 24 per cent (Exhibit B-1, page 5-68, lines 8 to 11).

The table below details the distribution of customer households flagged as low-income in the 2014 REUS data using Statistics Canada's standard LICOs for the 2013 tax year.

% of LICO	Frequency	Percent
0 - 25%	0	0.0
26 - 50%	39	5.4
51 - 75%	155	21.5
76 - 100%	527	73.1
Total	720	100

No customer households were categorized as falling in the 0 to 25 per cent of LICO range because the 25 per cent of LICO threshold is considerably lower than the top of the lowest income bracket in the REUS (under $20,000).

As noted in Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1, MSDSI makes direct payments to BC Hydro for about 6,000 of its clients while the remaining clients pay their own electricity bill. BC Hydro is unable to exclude the MSDSI direct payment clients from other customers with incomes at or below the pre-tax LICO.

115.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.115.1 For each band of LICO in the immediately preceding response, provide:

(a) The average income; and
(b) The median income.

RESPONSE:

BC Hydro does not collect the specific income of each customer that responds through the REUS. Instead, customers indicate which income bracket their income falls within (e.g., under $20,000, $20,000 to under $30,000, etc.). For this reason, the requested calculations cannot be conducted.

116.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.116.1 Please provide by year for each year from 2012 to 2015, inclusive, disaggregated by heating and non-heating customers:

(a) The number of low income customers whose utility bills are being paid directly by a government agency to BC Hydro that would fall within the 30% of highest residential users; and
(b) The number of low income customers whose utility bills are being paid directly by a government agency to BC Hydro that would fall within the 50% of highest residential users.

RESPONSE:

BC Hydro cannot identify MSDSI direct payment customers historically.

Among the 5,521 customers whose BC Hydro bills are currently being paid directly by MSDSI, the following are within 30 per cent and 50 per cent of highest residential users:

	Within 30% of Highest Residential Users	Within 50% of Highest Residential Users
Electric Heated	**820**	**1,433**
Non-Electric Heated	**735**	**1,130**
Total	**1,555**	**2,563**
Percentage of Direct Payment Customers (%)	**28**	**46**

117.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.117.1 Please provide all documents within BC Hydro's custody or control which, for the United States or Canada, identifies and/or otherwise discusses the penetration of market-based energy efficiency measures in low income households.

RESPONSE:

BC Hydro respectfully declines to respond to this IR, which concerns BC Hydro's RIB Report-related proposals, on the following basis:

- **The IR is vague. It is not clear what is meant by the phrase "penetration of market-based energy efficiency measures". For example, it is not clear if "market-based efficiency measures" includes government policy tools such as mandatory standards that sway purchase, retail stocking and production decisions toward energy-efficient products, or if the phrase is confined to utility delivered DSM programs or extends to third party providers; and**

- **The IR is very broad in scope, and requests documents beyond what is reasonably required to address Questions 1 to 5 in the Minister RIB Report Letter, and therefore are of limited or no relevance. The IR is unbounded in terms of time-frame. The IR appears to seek documents concerning any and all "market-based energy efficiency measures", which likely includes any and all DSM programs and perhaps codes and standards, whether initiated in in Canada or the U.S.**

118.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.118.1 Please provide an outline of any methodology or process that BC Hydro would find acceptable to dollarize and quantify the utility-related non-energy benefits (e.g., reduced bad debt, reduced arrearages, etc.) resulting from residential usage reduction generally and from low income usage reduction in particular.

RESPONSE:

BC Hydro has not undertaken a detailed review of the utility-related non-energy benefits that result from reduced Residential usage, and accordingly it is not possible for BC Hydro to identify what it would consider acceptable as a methodology.

In conceptual terms, the magnitude of non-energy benefits would depend on whether a customer's usage reduction was sufficient to enable him or her to avoid arrears altogether or if the customer continued to have arrears but the outstanding balance was lower. If arrears were avoided then BC Hydro would not incur Dunning costs and there would be no risk of bad debts. If arrears were not avoided then reduced consumption may not change the likelihood of incurring bad debts but would reduce the outstanding balance at risk of being written off.

119.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.119.1 For so-called "de facto electric heating" (defined as the situation in which a residential customer relies on portable electric heating as a primary source of heating even though the residence is configured to be heated primarily with gas service), please describe:

(a) Any DSM projects that have specifically addressed such de facto electric heating; and
(b) Any impediments to addressing such de facto electric heating within the context of BC Hydro's DSM programs.

RESPONSE:

BC Hydro does not target customers with primary gas heat for residential DSM electric heat programs. Please refer to BC Hydro's response to BCOAPO IR 1.103.3.

120.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.120.1 Please identify and provide a description of, for the years January 2010 to 2015 inclusive, all affirmative efforts by BC Hydro (outside the low income programs described in Section 5.6.2 of the Application):

(a) To target DSM marketing to low income customers (and the results therefrom);
(b) To develop information regarding the low income DSM market (and the results therefrom);
(c) To identify low income market niches to serve with DSM if a broad-based low income program is not offered (and the results therefrom);
(d) To create piggyback programs to reach low income customers with DSM (and the results therefrom); and
(e) To develop partnerships with institutions serving low income customers to have those institutions deliver DSM (and the results therefrom).

RESPONSE:

BC Hydro offers low income DSM program offerings which provide most of the energy savings opportunities found in BC Hydro's Residential DSM programs in a way that addresses the barriers specific to low income customers. In general, it is not effective or efficient to target low income customers outside of the low income program offerings, although other no-cost offers are often highlighted to low income customers through these offerings. BC Hydro also looks for opportunities to coordinate its Residential programs on an ongoing basis, which would include partnerships with institutions serving low income customers such as MSDSI, BC Housing and BC Non-Profit Housing Association.

121.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.121.1 Provide any analysis that BC Hydro has undertaken of its residential customer population since January 2005 in which it assesses the propositions that:

(a) The greater the energy consumption is in the pre-treatment period, the greater the potential for energy savings; and
(b) The greater the energy bill arrearage is in the pre-treatment period, the greater the reductions in energy consumption realized by DSM investments.

RESPONSE:

It is not clear to BC Hydro what "pre-treatment" refers to, but BC Hydro assumes it refers prior to undertaking any DSM initiatives. While BC Hydro does not have any analysis that examines elasticity pre and post DSM initiatives, BC Hydro offers the following:

- **The 2013 RIB Evaluation Report found that higher consumption is co-related with higher price elasticity. Refer to pages 5-17 and 5-18 of Exhibit B-1; and**

- **There is no evidence of a correlation between income and price responsiveness of Residential customers. In this regard please refer to BC Hydro's BCOAPO IR 1.111.1.**

BC Hydro also notes that it has no evidence that customers in bill arrearage are mainly low income customers. Please refer to Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

122.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.122.1 Provide all analyses that BC Hydro has undertaken since January 2005 of its residential population assessing the extent to which, if at all:

(a) Households with energy bill arrearages in the pre-treatment period reduce their arrearages following DSM services;
(b) The number of complete payments changes following DSM services; and
(c) The payment coverage ratio (i.e., payments as a percentage of billed revenue) changes following DSM services.

RESPONSE:

BC Hydro has not assessed the impacts on customers' on-time payment performance following participation in a low income DSM program.

123.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.123.1 Please identify and provide any documents within BC Hydro's custody or control finding or otherwise discussing whether, and if so how and to what extent, utility-funded DSM programs tend to exclude low income customers without a low income set-aside.

RESPONSE:

There are barriers to low income customers participating in Residential DSM programs, which is why BC Hydro offers low income DSM program offerings. Please refer to BC Hydro's response to BCOAPO IR 1.120.1.

BC Hydro's jurisdictional assessment of low-income DSM programs is found in Exhibit B-1, Appendix C3-D, pages 38 to 45 of 67. BC Hydro's conclusion is that its two DSM program offerings are consistent with the Canadian electric utilities that were surveyed.

124.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.124.1 Please identify all market barriers that impede or prevent a customer from installing cost-effective DSM measures in the absence of external assistance if the customer is:

(a) A residential customer irrespective of income; and
(b) A low income residential customer.

RESPONSE:

BC Hydro designs its DSM programs to address the following barriers:

- **Affordability**
- **Awareness**
- **Availability**
- **Accessibility**
- **Acceptability.**

These barriers to varying degrees apply to both (a) residential customers irrespective of income and (b) low income residential customers.

125.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.125.1 Please identify and provide any document within BC Hydro's custody or control discussing implicit discount rates (sometimes known as hurdle rates or internal rates of return) for residential DSM measures by income.

RESPONSE:

BC Hydro notes that this IR is asked in the context of BC Hydro's proposed approach to address the five questions set out in the Minister RIB Report Letter. BC Hydro has not studied implicit discount rates for Residential DSM programs by income.

126.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.126.1 Please provide all documents within BC Hydro's custody or control discussing the extent to which, if at all, DSM measures delivered to low income customers result in the following associated with the customers:

(a) Reduced arrearages;
(b) Reduced bad debt expense;
(c) Reduced credit and collection activity;
(d) Improved timeliness of payments; and
(e) Improved completeness of payments.

RESPONSE:

The evaluations of DSM measures have focussed on the energy savings resulting from the respective programs. BC Hydro has not undertaken studies to determine the impacts on payment history or arrearages.

127.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.127.1 Confirm or deny each of the following statements. If denied, provide a detailed explanation of the basis for the denial. All other things being equal:

(a) A reduced level of residential arrearages reduces BC Hydro's revenue requirement;
(b) A reduced level of residential bad debt reduces BC Hydro's revenue requirement;
(c) A reduced level of credit and collection activities reduces BC Hydro's revenue requirement;
(d) Improved timeliness of residential payments reduces BC Hydro's revenue requirement; and
(e) Improved completeness of residential payments reduces BC Hydro's revenue requirement.

RESPONSE:

As outlined in Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1, most of BC Hydro's credit and collection costs for active accounts are recovered through the Late Payment Charge and Reconnection Charge. Accordingly, reductions in most of BC Hydro's collections costs reduce the associated Standard Charges rather than BC Hydro's overall revenue requirement.

However, with this in mind, the conceptual impacts to BC Hydro's revenue requirements are as follows:

(a) Lower residential arrearage reduces BC Hydro's revenue requirement for costs of borrowing because of less delayed revenue;

(b) Lower residential bad debt reduces BC Hydro's revenue requirement for bad debt expense;

(c) Reduced credit and collection activities reduce BC Hydro's revenue requirement for the portions of those costs that are not recovered through the Late Payment Charge or Reconnection Charge. E.g., costs of disconnecting a customer that does not pay to reinstate service; and

(d) and (e) are the same as (a) in that the timeliness of payments impacts costs of borrowing.

128.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.128.1 Please explain each way in which, if at all, BC Hydro uses the following factors to target the delivery of residential DSM investments:

(a) Usage of the customer as a percentage of the residential mean or median usage;
(b) Level of arrearages of the customer;
(c) Length of residence of the customer at the housing unit to be treated; and
(d) Credit and collection or payment history of the customer.

RESPONSE:

BC Hydro uses aggregated metering data and preponderance modeling of higher electrical consumption and electric heating load to target neighbourhoods with awareness campaigns for programs that can assist customers with reducing high heating load.

BC Hydro does not use the level of arrearages of the customer or the length of residence of the customer at their home to target the delivery of DSM programs. However, credit and collection agents at the BC Hydro call centre are trained to identify customers that likely meet the criteria for BC Hydro's low income program offerings and offer enrollment in the ESK program as part of the solution to the customer's credit issues.

129.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.129.1 Please describe all ways in which there is an integration of BC Hydro's utility-funded residential DSM programs with each of the following:

(a) Requests for deferred payment plans;
(b) Disconnections for nonpayment;
(c) Requests for crisis assistance; and
(d) Receipt of direct bill payment assistance from the Government.

RESPONSE:

Regardless of call reasons, customers with outstanding balances are identified by the IVR and are routed to a special team in the call centre. Agents in this team promote BC Hydro's Residential DSM program offerings to customers.

For all other calls, all call centre agents are trained on Residential DSM program offerings and can address program details.

130.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.130.1 Please identify and provide all documents prepared since January 2010 which identify or otherwise discuss:

(a) The existing institutional capacity to deliver low income DSM in British Columbia; and
(b) The potential institutional capacity to deliver low income DSM in British Columbia.

RESPONSE:

BC Hydro respectfully declines to respond to this IR, which concerns BC Hydro's RIB Report-related proposals, on the following basis:

- **The IR is vague. It is not clear what is meant by the phrases "existing institutional capacity to deliver low income DSM programs" or "potential institutional capacity to deliver low income DSM" in B.C. For example, "institutional capacity to deliver" could refer to a wide array of potential barriers to the delivery of DSM programs; and**

- **The IR is very broad in scope, and requests documents beyond what is reasonably required to address Questions 1 to 5 in the Minister RIB Report Letter, and therefore are of limited or no relevance. The IR appears to seek documents concerning not only BC Hydro but also FortisBC and perhaps the B.C. Government's "existing" and "potential institutional capacity to deliver low income DSM programs".**

131.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.131.1 Please identify and provide a copy of all documents prepared by or for BC Hydro since January 2010 identifying and/or discussing:

(a) The technical potential for DSM savings for low income residential customers in BC Hydro's service territory;
(b) The economic potential for DSM savings for low income residential customers in BC Hydro's service territory;
(c) The percentage of technical potential for low income residential customers in BC Hydro's service territory yet to be realized; and
(d) The percentage of economic potential for low income residential customers in BC Hydro's service territory yet to be realized.

RESPONSE:

This IR is posed with respect to BC Hydro's proposed approach to the Minister RIB Report Letter. As noted in BC Hydro's response to BCOAPO IR 1.102.1, it has not been established that the RIB rate results in bill impacts of 10 per cent or greater for BC Hydro's low income customers. It is therefore premature to engage in review of BC Hydro's low income DSM programs as part of the RIB Report process.

To be responsive BC Hydro notes the following. Technical and economic potential are types of conservation potential determined during a CPR.[1] The last CPR that BC Hydro conducted was in 2007 and is therefore outside the timeline of this IR. As noted in BC Hydro's response to BCSEA IR 1.10.1, BC Hydro is working with FortisBC Energy Inc. (natural gas) and FortisBC Inc. (electricity), with involvement by Pacific Northern Gas, to conduct a joint CPR. The CPR project has recently started and as such, project milestones are still being confirmed, but it is expected that there will be results available in F2017.

It should be noted that a CPR is based on an approach where conservation potential is identified largely by buildings (including equipment and industrial processes) and does not take into account demographics such as income.

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[1] **As noted in BC Hydro's response to COPE IR 1.19.2, technical potential is the theoretical case that provides the broadest and highest definition of savings potential. Technical potential does not take into account the cost-effectiveness of potential DSM measures, while economic potential represents the adoption of all cost-effective conservation measures within a defined price threshold.**

132.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.132.1 Please identify and provide a copy of all documents prepared by or for BC Hydro since January 2010 identifying and/or discussing:

(a) The technical potential for DSM savings for residential customers irrespective of income in BC Hydro's service territory;
(b) The economic potential for DSM savings for residential customers irrespective of income in BC Hydro's service territory;
(c) The percentage of technical potential for residential customers irrespective of income in BC Hydro's service territory yet to be realized; and
(d) The percentage of economic potential for residential customers irrespective of income in BC Hydro's service territory yet to be realized.

RESPONSE:

This IR is posed with respect to BC Hydro's proposed approach to the Minister RIB Report Letter. Questions 4 and 5 of the Minister RIB Report Letter relate to DSM programs concerning low income customers and customers without access to natural gas. Accordingly, requests for CPRs concerning all Residential DSM programs is not relevant to and cannot assist with the review of the 2015 RDA or for purposes of responding to the Minister RIB Report Letter.

To be responsive, BC Hydro notes that its last CPR was conducted in 2007. Please refer to BC Hydro's response to BCOAPO IR 1.131.1.

133.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.133.1 By residential DSM measure for each year from January 2010 to present, please provide the average installed cost. Separately provide, disaggregated by heating and non-heating customers where available, the per-household total average treatment cost of a residential unit by year during the same time period.

RESPONSE:

BC Hydro respectfully declines to respond to this IR, which concerns BC Hydro's RIB Report-related proposals, on the basis that the information sought is not relevant to and cannot aid in the review of the 2015 RDA or the orders sought in respect of it, or for purposes of to the Minister RIB Report Letter. The information sought in this IR, which concerns the 'average installed cost' information for all BC Hydro Residential DSM measures which would include both program and codes and standards, and per-household total average treatment cost of a residential unit by year for a five-year period, is not reasonably required to respond to Questions 1 to 5 of the Minister RIB Report Letter.

134.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.134.1 Please identify and provide a copy of all documents within BC Hydro's custody or control describing a low income DSM electric program in the United States or Canada that is a:

(a) Parallel program, defined to be a program in which a government agency runs two programs, one funded and designed by a government agency and a parallel one funded and designed by an electric utility.
(b) Supplemental program, defined to be a program in which the program relies on utility funding to support a government agency's ongoing program, with no changes in the program's design or operation; and
(c) Coupled program, in which a government agency and electric utility fund, design and implement the energy efficiency efforts.
(d) For each program identified in response to the question immediately above, please provide a brief description of all factors, if any, that would make such a program infeasible or uneconomic for BC Hydro.

RESPONSE:

BC Hydro respectfully declines to respond to this IR, which concerns BC Hydro's RIB Report-related proposals, on the basis that the information sought is not relevant to and cannot aid in the review of the 2015 RDA or the orders sought in respect of it, or for the purposes of the Minister RIB Report Letter. The documents sought in this IR, which cover a wide range of potential low income DSM program-related information for both Canada and the U.S., are not reasonably required to respond to Questions 4 or 5 of the Minister RIB Report Letter.

BC Hydro's jurisdictional assessment of low income rates/low income terms and conditions/low income DSM programs is contained at Exhibit B-1, Appendix C-3D, pages 38 to 51 of 67. BC Hydro reviewed the low income DSM programs of Canadian jurisdictions but not of U.S. jurisdictions. BC Hydro respectfully submits that this jurisdictional information is sufficient, if required, to answer Questions 4 and 5 of the Minister RIB Report Letter.

135.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency – First Nations

1.135.1 Provide a breakdown of residential electricity consumption on First Nations reserve and treaty lands in BC by month, broken down by:

(a) Income, including LICO, LICO plus 30% and income above LICO plus 30%;
(b) Dwelling type;
(c) Heating type; and
(d) Household size.

RESPONSE:

Please refer to Attachment 1 to this IR. Note that the analysis is based on 107 accounts in the 2014 REUS that are located on First Nations reserve and treaty lands and that are billed on the RIB rate. The tables in Attachment 1 detail the mean monthly consumption values for F2015 as well as the weighted base sizes for each sub-group. Note that some base sizes are small; caution is warranted in generalizing these findings to the sub-populations of interest.

BC Hydro respectfully declines to respond to the IR using LICO multiplied by 1.3 for the reasons set out in BC Hydro's response to BCOAPO IR 1.114.1.

APR14_kWh MAY14_kWh JUN14_kWh JUL14_kWh AUG14_kWh SEP14_kWh OCT14_kWh NOV14_kWh DEC14_kWh JAN15_kWh FEB15_kWh MAR15_kWh * Income collapse 2

Income collapse 2		APR14_kWh	MAY14_kWh	JUN14_kWh	JUL14_kWh	AUG14_kWh	SEP14_kWh	OCT14_kWh	NOV14_kWh	DEC14_kWh	JAN15_kWh	FEB15_kWh	MAR15_kWh
Under $40,000	Mean	787.082	633.286	578.204	733.127	694.400	588.464	738.759	1019.217	1160.765	1094.892	897.122	905.637
	N	20	20	20	20	20	20	20	20	20	20	20	20
$40,000 to under $80,000	Mean	904.922	763.222	681.725	834.549	869.930	719.010	805.482	1104.971	1251.471	1219.865	947.215	925.738
	N	20	20	20	20	20	20	20	20	20	20	20	20
$80,000 +	Mean	785.998	676.015	635.143	865.726	835.668	640.503	685.280	1026.823	1170.391	1050.509	868.346	799.725
	N	10	10	10	10	10	10	10	10	10	10	10	10
Total	Mean	833.945	694.039	631.340	801.064	793.742	651.386	754.365	1055.056	1199.000	1135.655	911.190	891.775
	N	50	50	50	50	50	50	50	50	50	50	50	50

APR14_kWh MAY14_kWh JUN14_kWh JUL14_kWh AUG14_kWh SEP14_kWh OCT14_kWh NOV14_kWh DEC14_kWh JAN15_kWh FEB15_kWh MAR15_kWh * Final LICO Status - Final

Final LICO Status - Final		APR14_kWh	MAY14_kWh	JUN14_kWh	JUL14_kWh	AUG14_kWh	SEP14_kWh	OCT14_kWh	NOV14_kWh	DEC14_kWh	JAN15_kWh	FEB15_kWh	MAR15_kWh
No - Not Low Income	Mean	773.234	641.828	580.033	737.021	726.589	597.288	701.164	999.002	1146.671	1076.876	848.600	829.201
	N	57	57	57	57	57	57	57	57	57	57	57	57
Yes - Low Income	Mean	941.568	787.700	752.897	896.629	865.489	787.986	858.821	974.365	1064.689	1103.071	937.757	994.479
	N	8	8	8	8	8	8	8	8	8	8	8	8
Total	Mean	793.001	658.958	600.332	755.764	742.900	619.681	719.677	996.109	1137.044	1079.952	859.069	848.610
	N	64	64	64	64	64	64	64	64	64	64	64	64

APR14_kWh MAY14_kWh JUN14_kWh JUL14_kWh AUG14_kWh SEP14_kWh OCT14_kWh NOV14_kWh DEC14_kWh JAN15_kWh FEB15_kWh MAR15_kWh * Dwelling Collapse - Main

Dwelling Collapse - Main		APR14_kWh	MAY14_kWh	JUN14_kWh	JUL14_kWh	AUG14_kWh	SEP14_kWh	OCT14_kWh	NOV14_kWh	DEC14_kWh	JAN15_kWh	FEB15_kWh	MAR15_kWh
Single detached house	Mean	846.878	707.785	637.500	797.551	810.672	650.969	751.436	1025.101	1163.269	1086.049	864.393	850.399
	N	27	27	27	27	27	27	27	27	27	27	27	27
Duplex/Row/Town	Mean	1155.776	828.901	758.770	737.608	735.418	728.009	882.580	1204.174	1480.089	1512.595	1213.468	1221.227
	N	3	3	3	3	3	3	3	3	3	3	3	3
Apartment/condominium	Mean	337.405	303.292	326.625	468.665	395.935	380.195	367.640	493.820	547.616	563.382	405.780	408.958
	N	5	5	5	5	5	5	5	5	5	5	5	5
Mobile/other	Mean	790.399	662.513	600.569	772.586	746.004	624.156	738.834	1040.832	1186.367	1124.861	901.120	889.471
	N	29	29	29	29	29	29	29	29	29	29	29	29
Total	Mean	793.001	658.958	600.332	755.764	742.900	619.681	719.677	996.109	1137.044	1079.952	859.069	848.610
	N	64	64	64	64	64	64	64	64	64	64	64	64

APR14_kWh MAY14_kWh JUN14_kWh JUL14_kWh AUG14_kWh SEP14_kWh OCT14_kWh NOV14_kWh DEC14_kWh JAN15_kWh FEB15_kWh MAR15_kWh * MAIN HEATING FUEL FINAL - COLLAPSE 3

MAIN HEATING FUEL FINAL - COLLAPSE 3		APR14_kWh	MAY14_kWh	JUN14_kWh	JUL14_kWh	AUG14_kWh	SEP14_kWh	OCT14_kWh	NOV14_kWh	DEC14_kWh	JAN15_kWh	FEB15_kWh	MAR15_kWh
Electricity	Mean	1055.816	807.987	710.470	789.328	810.223	719.634	907.773	1399.867	1601.648	1503.116	1152.132	1128.303
	N	27	27	27	27	27	27	27	27	27	27	27	27
Non-Electric	Mean	605.663	555.134	523.696	734.940	695.892	550.811	587.098	705.748	802.821	776.049	649.880	649.293
	N	37	37	37	37	37	37	37	37	37	37	37	37
Not applicable - there is no home heating	Mean	0.000	0.000	105.224	384.845	454.457	111.339	21.781	0.000	0.000	0.000	0.000	0.000
	N												
Total	Mean	793.001	658.958	600.332	755.764	742.900	619.681	719.677	996.109	1137.044	1079.952	859.069	848.610
	N	64	64	64	64	64	64	64	64	64	64	64	64

APR14_kWh MAY14_kWh JUN14_kWh JUL14_kWh AUG14_kWh SEP14_kWh OCT14_kWh NOV14_kWh DEC14_kWh JAN15_kWh FEB15_kWh MAR15_kWh * Household size recode 2

Household size recode 2		APR14_kWh	MAY14_kWh	JUN14_kWh	JUL14_kWh	AUG14_kWh	SEP14_kWh	OCT14_kWh	NOV14_kWh	DEC14_kWh	JAN15_kWh	FEB15_kWh	MAR15_kWh
1	Mean	526.755	424.569	389.709	517.559	487.136	396.672	485.659	661.423	776.558	706.467	565.912	575.363
	N	14	14	14	14	14	14	14	14	14	14	14	14
2	Mean	830.453	711.752	641.360	814.746	808.934	647.005	765.309	1112.022	1256.408	1188.326	929.108	894.749
	N	32	32	32	32	32	32	32	32	32	32	32	32
3	Mean	1174.821	843.111	761.610	898.258	896.064	850.111	1176.564	1552.358	1724.820	1693.574	1345.564	1337.850
	N	3	3	3	3	3	3	3	3	3	3	3	3
4 or more	Mean	965.259	807.406	774.167	917.413	889.586	799.889	830.687	995.167	1108.205	1086.632	943.448	967.434
	N	11	11	11	11	11	11	11	11	11	11	11	11
Total	Mean	805.106	671.217	615.416	770.657	755.224	629.662	735.921	1010.457	1143.712	1085.992	871.173	859.368
	N	60	60	60	60	60	60	60	60	60	60	60	60

135.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency – First Nations

1.135.2 Provide the number of residential customer accounts on First Nations reserve and treaty lands in BC, broken down by income, including LICO, LICO plus 30% and income above LICO plus 30%.

RESPONSE:

Based on 28,342 customer accounts on First Nations reserve and treaty lands in BC Hydro's service area, the 2014 REUS estimates that: 12,174 of these households have total incomes under $40,000; 11,042 households have total incomes $40,000 to under $80,000; and 5,125 households have total incomes of $80,000 or over.

Based on 28,342 customer accounts on First Nations reserve and treaty lands in BC Hydro's service area, the 2014 REUS estimates that 3,670 of these households are low income.

BC Hydro respectfully declines to respond to the IR using LICO multiplied by 1.3 for the reasons set out in BC Hydro's response to BCOAPO IR 1.114.1.

135.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency – First Nations

1.135.3 Describe the eligibility criteria and assessment process for ECAP for First Nations and whether the eligibility criteria and assessment process are different than applications from customers who are not First Nations.

RESPONSE:

First Nations communities can participate in ECAP using a bulk application process. Through the bulk process, individual community members are not required to submit proof of income documents to BC Hydro. Instead the band identifies income qualified community members and informs them of the program and band members choose to participate in the program by completing an application form. A similar bulk process is used for non-profit housing providers.

The only difference in the assessment for First Nation communities is that the program's contractor typically hires assistant evaluators from the community to assist with the installations.

Individual on-reserve households can also apply for ECAP outside of the bulk application process by using the standard individual application process.

135.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency – First Nations

1.135.4 How does BC Hydro address privacy issues related to income verification and eligibility assessment for ECAP and ESKs, for First Nations and non-First Nations applicants, if the process is different?

RESPONSE:

Please refer to section 5.1 of Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

135.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency – First Nations

1.135.5 Is BC Hydro developing a First Nations Power Smart program?

RESPONSE:

First Nations communities can participate in all of BC Hydro's suite of Residential DSM programs, including the two low income DSM program offerings. BC Hydro is currently developing a pilot offer for First Nations and remote communities in an attempt to further address the unique market barriers for these communities.

135.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency – First Nations

1.135.5 Is BC Hydro developing a First Nations Power Smart program?

1.135.5.1 If so, please describe the program and when BC Hydro plans to implement the program.

RESPONSE:

The pilot referenced in BC Hydro's response to BCOAPO IR 1.135.5 builds on the low income program model and aims to:

- **Support education and skills training to build energy literacy in the community, empower community members to manage energy use and reduce energy costs, and foster local economic development opportunities related to energy;**
- **Facilitate access to opportunity assessments and energy efficient upgrades for homes and community buildings to reduce electric bills;**
- **Support the development and implementation of energy efficient housing policy to ensure that new homes on reserves are built to higher energy performance standards and that existing homes are upgraded to improve energy performance over time; and**
- **Support the development of community energy plans that articulate both short and long-term opportunities and priorities for community energy management.**

BC Hydro plans to run the pilot with two communities in F2016-F2017.

135.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency – First Nations

1.135.6 Does BC Hydro leverage dollars with Indigenous and Northern Affairs Canada to install ECAP where mould or other health and safety issues prevent installation of weatherization DSM measures on First Nations reserve and treaty lands?

RESPONSE:

There is no formal coordination with the federal program and ECAP. Discussions are under way with Indigenous and Northern Affairs Canada and other organizations to look for ways to coordinate funding.

135.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency – First Nations

1.135.7 How many households, annually, receive Advanced ECAP and how many receive Basic ECAP for the entire program?

RESPONSE:

In F2015, 1148 homes received ECAP Basic offerings and 62 electrically heated homes received ECAP Advanced offerings.

135.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency – First Nations

1.135.8 How many First Nations households, annually, receive Advanced ECAP and how many receive Basic ECAP?

RESPONSE:

In F2015, 111 First Nation households participated in ECAP Basic offerings. No First Nation households participated in ECAP Advanced offerings.

135.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency – First Nations

1.135.9 What fraction of households that receive ECAP do not receive any air sealing measures program wide?

RESPONSE:

In F2015, 14.4 per cent of ECAP Basic participants did not receive any air sealing measures.

135.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency – First Nations

1.135.10 What fraction of First Nations households that receive ECAP do not receive any air sealing measures?

RESPONSE:

In F2015, 13.5 per cent of First Nation ECAP Basic participants did not receive any air sealing measures.

136.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.136.1 Are there any income support programs other than those listed in the definition of "low income household" in the Demand Side Measures Regulation at: http://www.bclaws.ca/civix/document/id/complete/statreg/326_2008 that BC Hydro currently accepts as proof of income for the purpose of qualifying for ECAP and ESKs?

RESPONSE:

No, there are no other income support programs that BC Hydro currently accepts as proof of income for the purposes of qualifying for ECAP other than those listed in the definition of "low income household" in the DSM Regulation. To clarify, ESK participation does not require proof of income. Proof of income is only collected for the ECAP program.

There are cases within the ECAP program where individual proof of income requirement is waived. One example is the bulk application process with First Nations communities. The band office will identify community members that it knows meet the income requirements and those community members can choose to apply for the program. A similar process is used for non-profit housing provider or community service organizations that qualify clients on income for other purposes.

136.0 CHAPTER 5 RESIDENTIAL RATE DESIGN

Reference: Exhibit B-1, Section 5.6.2
Low income energy efficiency

1.136.2 If a BC Hydro customer receives social assistance through Indigenous Affairs and Northern Development Canada, would proof of this income be sufficient for such a customer to apply for ECAP and ESKs?

RESPONSE:

Proof of income is not required for a customer to apply for an ESK, only for the ECAP. As described in BC Hydro's response to BCOAPO IR 1.135.3, it has been BC Hydro's experience that on-reserve aboriginal community members typically participate in the program through a bulk application process, in which case BC Hydro does not collect individual income documents.

BC Hydro would be willing to consider amending its program policies regarding proof of income if it can be demonstrated that this is a barrier to participating in the low income program offerings.

137.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-8 to 6-12

1.137.1 Please clarify what is meant by customer-related costs (page 6-8) and indicate what the dollar value for customer-related costs is for the SGS class based on the F2016 COSS, providing the necessary cross-references to the F2016 COSS – per Appendix E.

RESPONSE:

As discussed in BC Hydro's response to BCOAPO IR 1.67.2 Customer-related costs are comprised of BC Hydro's Distribution metering, transformer and customer costs and Customer Care-related costs.

Total Customer-related costs assigned to the SGS class in the F2016 COS are $45.2 million, as computed in cell H5 of sheet 4.1 in the excel file attached to Appendix E of Exhibit B-1.

Specific references to the classification and allocation of the components of customer-related costs as assigned to the SGS class can be traced back through the F2016 COS excel file from cell H5 of sheet 4.1.

137.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-8 to 6-12

1.137.2 Based on the F2016 SGS billing determinants (i.e., customers and energy) please provide the calculations demonstrating that the current F2016 basic charge recovers 35% of customer-related costs.

RESPONSE:

F2016 forecast basic charge revenue is estimated to equal approximately $15.3 million, based on 185,817 accounts *multiplied by* 22.57 cents per day *multiplied by* 365 days.

F2016 forecast basic charge revenue of $15.3 million *divided by* total SGS assigned customer related costs of $45.2 million *is equal to* about 34 per cent, or 35 per cent if rounding to the nearest 5 per cent.

137.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-8 to 6-12

1.137.3 Does BC Hydro anticipate/foresee any issues arising from the fact the proposed basic charge for SGS (32 cents/day in F2017) will exceed the proposed basic charge for MGS customers (23.47 cents/day in F2017) – such that smaller customers will be seeing a higher basic charge?

RESPONSE:

BC Hydro does not foresee any issues arising from a difference between the absolute level of SGS and MGS basic charges, for the reasons set out in BC Hydro's response to BCUC IR 1.54.1.

138.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, page 55

1.138.1 Given that increasing the basic charge's recovery of customer related costs from 35% to 45% would require an increase of 28.6% (45/35) why is the escalation factor 1.36?

RESPONSE:

The description in Exhibit B-1 is rounded to the nearest 5 per cent. The precise escalation is from 33 per cent to 45 per cent; 45 per cent/33 per cent yields a factor of 1.36.

138.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, page 55

1.138.2 Please indicate how the 1.36 escalation factor for the SGS basic charge was determined.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.138.1.

139.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, page 55

1.139.1 Please provide a schedule similar to Table H-1A-43 (rows A-K) but for F2016 based on the approved rates. Please reconcile the revenues that result with those used in the COSS (Schedule 4.0) for the SGS class.

RESPONSE:

Exhibit B-1, Table H-1A-43 produced for F2016 rates is as follows

A	Basic Charge ($/day)	$	0.2257	
B	Number of accounts		180,367	October 2014 Load Forecast
C	**Forecast Basic Revenue**	**$**	**14,858,696**	**BxAx365**
D	Energy Rate ($/kWh)	$	0.1073	
E	Energy Forecast (GWh)		3,680.32	October 2014 Load Forecast
F	**Forecast Energy Revenue**	**$**	**394,898,155**	**DxEx1,000,000**
G	**Discounts**	**$**	**(87,225)**	**Est. same as SQ**
H	**Total forecast Revenue before rate rider**	**$**	**409,669,627**	**C+F+G**
I	Rate Rider		5%	
J	Forecast Revenue with Rate Rider	$	430,153,108	H x (1+I)
K	Target Revenue with Rate Rider	$	429,715,527	From Finance
L	Variance	$	437,581	J-K
M	**Variance**		**0.102%**	**L/J-1**

Schedule 4.0 of Appendix E shows a target revenue of $411.8 million, which is comparable to line H above. The difference is due to the inclusion of the NIAs, which is not part of the rate model.

140.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, pages 53-59

For purposes of modelling BC Hydro has calculated the "proposed SGS rates" for F2017-F2018 so as to be revenue neutral to revenue assuming the status quo rates for each year (page 53). BC Hydro proposes to implement the SGS changes April 1, 2017.

1.140.1 How will the increase in the basic charge for F2018 (over the F2017 basic charge) be determined, assuming the F2018 RRA increase is 3.5%?

RESPONSE:

If the implementation of the SGS changes is April 1, 2017 (F2018) and assuming that the proposed SGS rate is approved, then the basic charge will be determined by escalating the F2017 target revenue to be collected from SGS basic charge under the status quo rate structure by a factor that yields a customer-related cost recovery of 45 per cent, using the best available data at the time of the F2018 compliance filing.

140.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, pages 53-59

For purposes of modelling BC Hydro has calculated the "proposed SGS rates" for F2017-F2018 so as to be revenue neutral to revenue assuming the status quo rates for each year (page 53). BC Hydro proposes to implement the SGS changes April 1, 2017.

1.140.2 How will the F2018 energy charge be determined? Will it be determined so as to maintain revenue neutrality as if the status quo rate design had been maintained for F2018?

RESPONSE:

If the implementation of the SGS changes is April 1, 2017 (F2018) and assuming that the proposed SGS rate is approved, then the energy charge will be determined to recover the target revenue which will be based on the status quo design as informed by the approved RRA at the time of the F2018 compliance filing.

140.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, pages 53-59

For purposes of modelling BC Hydro has calculated the "proposed SGS rates" for F2017-F2018 so as to be revenue neutral to revenue assuming the status quo rates for each year (page 53). BC Hydro proposes to implement the SGS changes April 1, 2017.

1.140.3 How will revenue neutrality be defined for F2019? Will it be based on: a) revenues for F2019 assuming the status quo rate design had been maintained through to F2019 and applying the RRA increases or b) determining the F2019 revenues using the SGS rates approved for F2018 and escalating the results by the RRA for F2019?

RESPONSE:

The target revenue for the SGS rate class as informed by the approved RRA at the time of the F2019 compliance filing.

141.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, page 6-10

1.141.1 Assuming BC Hydro's rate increases for F2017 through F2019 match the rate caps set out on page 1-2, please provide a schedule that compares the SGS energy rates for F2018 and F2019 with the LRMC range for each of these years as set out in Table 2-6.

RESPONSE:

	Energy Rate of Proposed SGS Design (cents/kWh)	**Table 2-6 LRMC (Low – High) (cents/kWh)**
F2018	**11.39**	**9.65 – 11.35**
F2019	**11.73**	**9.84 – 11.58**

142.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, page 6-14

1.142.1 Please explain why, for the lowest and highest percentiles, the difference between the last two columns is not 4% - the F2017 RRA increase.

RESPONSE:

Before responding, Exhibit B-1, Table 6-3 has been revised as per BC Hydro's response to BCUC IR 1.55.1. The revised table, designated as Table 6-3A, is reproduced here for convenience. The revised values are shaded.

Table 6-3A Annual Bill Impacts of an Increase in the SGS Basic Charge to Recover 45 per cent of Customer-related Costs

Percentile by Consumption	Annual kWh	F2017 Annual Bill Status Quo ($)	F2017 Annual Bill BC Hydro Proposal ($)	Annual Bill Difference between F2017 BC Hydro Proposal and F2017 Status Quo ($)	Annual Bill Difference between F2017 BC Hydro Proposal and F2017 Status Quo (%)	Bill Impact of F2017 BC Hydro Proposal (vs. F2016 Rates) (%)
Min	1	86	117	31	36	42
10	2,001	309	337	28	9	13
20	4,773	618	642	24	4	8
30	7,797	956	975	19	2	6
40	11,184	1,334	1,348	14	1	5
50	15,288	1,792	1,800	8	0	4
60	20,648	2,390	2,390	0	0	4
70	28,435	3,259	3,247	-12	0	4
80	40,838	4,643	4,613	-30	-1	3
90	65,174	7,359	7,292	-67	-1	3
Max	615,810	68,810	67,918	-892	-1	3

BC Hydro does not see that subtracting the last two columns will provide any additional insights, as each column already shows the bill differences and bill impacts of the proposed SGS rate.

The calculations leading to the outcomes of the last two columns, for the lowest and highest percentiles (the minimum and maximum customer by consumption), are as follows:

The column "Annual Bill Difference Between F2017 BC Hydro Proposal and F2017 Status Quo" is calculated as follows:

Eq. A: (F2017 proposed rate Bill - F2017 SQ bill) / (F2017 SQ Bill) x 100%

The column "Bill Impact (%) of F2017 BC Hydro Proposal (vs. F2016 Rates) is calculated as follows:

Eq. B: (F2017 proposed rate Bill - F2016 SQ Bill)/(F2016 SQ Bill) x 100%

The illustrative bills are computed using tariff rates, excluding rate rider (for simplicity) as follows:

Consumption x energy rate + 365 days * basic charge.

For the Minimum customer,

F2017 proposed rate bill = 1 kWh * $0.1101/kWh + 365 days * $0.3200/day = $116.91
F2017 SQ bill = 1 kWh * $0.1116/kWh + 365 days * $0.2347/day = $85.78
F2016 bill = 1 kWh * $0.1073/kWh + 365 days * $0.2257/day = $82.49

Eq. A = ($116.91 – $85.78)/$85.78 x 100% = 36%
Eq. B = ($116.91 – $82.49)/$82.49 x 100% = 42%

For the Maximum customer,

F2017 proposed rate
bill = 615,810 kWh * $0.1101/kWh + 365 days * $0.3200/day = $67,917.48
F2017 SQ bill = 615,810 kWh * $0.1116/kWh + 365 days * $0.2347/day = $68,810.06
F2016 bill = 615,810 kWh * $0.1073/kWh + 365 days * $0.2257/day = $66,158.79

Eq. A = ($67,917.48 - $68,810.06)/$68,810.06x 100% = -1%
Eq. B = ($67,917.48 - $66,158.79)/$66,158.79x 100% = 3%

Note that the inclusion of DARR will not change the percentage bill difference and percentage bill impacts because it is identical for F2016 and F2017 under both designs.

143.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, page 6-32

1.143.1 Assuming BC Hydro's rate increases for F2017 through F2019 match the rate caps set out on page 1-2, please provide a schedule that compares the MGS energy rates for F2018 and F2019 with the LRMC range for each of these years as set out in Table 2-6.

RESPONSE:

	Energy Rate of Proposed MGS Design (cents/kWh)	**Table 2-6 LRMC (Low – High) (cents/kWh)**
F2018	**8.83**	**9.65 – 11.35**
F2019	**9.10**	**9.84 – 11.58**

144.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-30 and 6-34

1.144.1 Please clarify what is meant by demand-related costs and indicate what the dollar value is for the MGS class based on the F2016 COSS, providing the necessary cross-references to the F2016 COSS – per Appendix E.

RESPONSE:

Demand-related costs are comprised of BC Hydro's Generation demand, Transmission and Distribution demand and transformer costs.

Total demand-related costs assigned to the MGS class in the F2016 COS are $162.5 million, as computed in cell G6 of sheet 4.1 in the excel file attached to Appendix E of Exhibit B-1.

Specific references to the classification and allocation of the components of demand-related costs as assigned to the MGS class can be traced back through the F2016 COS excel file from cell G6 of sheet 4.1.

144.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-30 and 6-34

1.144.2 Based on the F2016 MGS billing determinants (i.e., customers, demand and energy) please provide the calculations demonstrating that the current F2016 demand charge recovers 15% of demand-related costs.

RESPONSE:

Forecast MGS demand revenue in F2016 equals $24.3 million. Dividing $24.3 million into total assigned MGS demand-related costs in the F2016 COS of $162.5 million equals 15 per cent.

Please refer to section 7 of Appendix H-1A for forecast MGS billing determinants for F2017-F2019.

144.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-30 and 6-34

1.144.3 What percentage of the customer-related costs allocated to MGS are recovered though the basic charge? In responding, please indicate what the dollar value for customer-related costs is for the MGS, providing the necessary cross-references to the F2016 COSS – per Appendix E.

RESPONSE:

Approximately 9 per cent of customer-related costs assigned to the MGS class are recovered through the basic charge.

The result is based on forecast F2017 MGS basic charge revenue of $1.45 million, as reported in Table H-1A-31 of Appendix H-1A of Exhibit B-1, *divided by* total customer-related costs assigned to the MGS class of $16.2 million, as computed in cell H6 of sheet 4.1 in the F2016 COS excel file attached to Appendix E of Exhibit B-1.

145.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-36 and 6-68

1.145.1 Please explain the difference between Figures 6-6 and 6-14. While the titles suggest both are showing the impacts of transitioning to BC Hydro's preferred MGS rate design in one year (6-6 net of the RRA and 6-14 including RRA), the differences between the values shown in the tables are more than the RRA increase for F2017.

RESPONSE:

Exhibit B-1, Figure 6-14 is bill impact including RRA, reproduced from Exhibit B-1, Appendix C-1B, page 84. It is simulated on the same vintage of assumptions as Workshop 12, so that it is comparable to the bill impacts of phase-in for Figure 6-15.

Exhibit B-1, Figure 6-6 is bill impact less RRA, simulated on the assumptions as stated in Exhibit B-1, Appendix H-1A, which is the latest available at the time of the Application.

If the RRA is removed from Figure 6-14, the outcome will be similar to Figure 6-6 and there are no substantive differences in the overall direction and magnitude of the patterns. The minor differences would be attributable to the different vintage of assumptions.

146.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, page 37

1.146.1 Please provide a schedule similar to Table H-1A-31 (rows A-AF) but for F2016 based on the approved rates. Please reconcile the revenues that result with those used in the COSS (Schedule 4.0) for the MGS class.

RESPONSE:

The table below is reproduced from BC Hydro Compliance with Commission Order No. G-48-14, ORIGINAL FILED March 18, 2015 – ERRATA No. 1 INFORMALLY SUBMITTED on March 20, 2015, Attachment 3, section 2.6, Table 11.

Schedule 4.0 shows a target revenue of $351.5 million, which is comparable to line AG divided by (1 + Rate Rider of 5%) = $351.5 million.

Line	Description	Value	Unit
A	Forecast Part 1, Tier 1 Class Load	2,514,078,934	kWh
B	Forecast Part 1, Tier 2 Class Load	1,107,498,563	kWh
C	Forecast Part 2 LRMC Class Load	11,966,801	kWh
D	Forecast Part 2 Tier 1 Class Load	(7,754,604)	kWh
E	Forecast Part 2 Tier 2 Class Load	3,111,032	kWh
F	Forecast Minimum energy charge Class load	30,408	kWh
G	Forecast Energy, MGS Class	3,628,931,135	kWh
H	Forecast Number of Accounts, MGS Class	17,155	
I	Forecast Class Demand Tier 1	6,956,764	kW
J	Forecast Class Demand Tier 2	4,423,223	KW
K	Forecast Class Demand Tier 3	12,082	kW
L	Tier 1 Energy Rate	9.89	cents/kWh
M	Tier 2 Energy Rate	6.90	cents/kWh
N	Part 2 LRMC Energy Rate	9.90	cents/kWh
O	Minimum Energy Charge	3.30	cents/kWh
P	Basic Charge	0.2257	$ / Day
Q	Tier 1 Demand Rate	-	$/kW
R	Tier 2 Demand Rate	5.50	$/kW
S	Tier 3 Demand Rate	10.55	$/kW
T	Forecast primary potential and transformation discounts	(88,391)	$
U	Tier 1 Energy Revenue	248,642,407	$
V	Tier 2 Energy Revenue	76,417,401	$
W	Part 2 LRMC Energy Revenue	1,184,713	$
X	Part 2 Tier 1 Energy Revenue	(766,930)	$
Y	Part 2 Tier 2 Energy Revenue	214,661	$
Z	Minimum Energy Charge Revenue	1,003	$
AA	Tier 1 Demand Revenue	-	$
AB	Tier 2 Demand Revenue	24,327,727	$
AC	Tier 3 Demand Revenue	127,465	$
AD	Basic Charge Revenue	1,417,109	$
AE	Rate Rider (%)	5	
AF	Total Forecasted Revenue (including rate rider)	369,051,023	$
AG	Target Revenue (including rate rider)	369,067,223	$
AH	Variance due to rates rounding	(16,200)	$
AI	Variance %	(0.004)	

147.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, page 43

1.147.1 Given that increasing the MGS demand charge's recovery of demand related costs from 15% to 35% would require an increase of 133% (35/15) why is the escalation factor 2.22 and not 2.33?

RESPONSE:

For simplicity, the MGS demand charge cost recovery percent was rounded to the nearest 5 per cent. The actual value used for the calculation was 15.8 per cent. The factor of 2.22 = 35/15.8.

147.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, page 43

1.147.2 Please indicate how the 2.22 escalation factor for the MGS demand charge cost recovery was determined.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.147.1.

148.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, pages 43-48

For purposes of modelling BC Hydro has calculated the "proposed rates" for F2017-F2018 so as to be revenue neutral to revenues assuming the status quo MGS rates for each year (page 43). BC Hydro proposes to implement the MGS changes April 1, 2017.

1.148.1 How will the flat demand charge for F2018 be determined, assuming the F2018 RRA increase is 3.5%?

RESPONSE:

If the implementation of the MGS changes is April 1, 2017 (F2018) and assuming that the proposed MGS rate is approved, then the demand charge will be determined by escalating the F2017 target revenue to be collected from demand charge under the status quo rate structure by a factor that yields a demand-related cost recovery of 35 per cent, using the best available data at the time of the F2018 compliance filing.

The basic charge will be escalated by the RRA.

The energy charge will be determined to recover the target revenue as informed by the approved RRA at the time of the F2018 compliance filing.

148.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, pages 43-48

For purposes of modelling BC Hydro has calculated the "proposed rates" for F2017-F2018 so as to be revenue neutral to revenues assuming the status quo MGS rates for each year (page 43). BC Hydro proposes to implement the MGS changes April 1, 2017.

1.148.2 How will the F2018 energy charge be determined? Will it be determined so as to maintain revenue neutrality as if the status quo rate design had been maintained for F2018?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.148.1.

148.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, pages 43-48

For purposes of modelling BC Hydro has calculated the "proposed rates" for F2017-F2018 so as to be revenue neutral to revenues assuming the status quo MGS rates for each year (page 43). BC Hydro proposes to implement the MGS changes April 1, 2017.

1.148.3 How will revenue neutrality be defined for F2019? Will it be based on: a) revenues for F2019 assuming the status quo rate design had been maintained through to F2018 and applying the RRA increases or b) determining the F2019 revenues using the MGS rates approved for F2018 and escalating the results by the RRA for F2019?

RESPONSE:

The target revenue for the MGS rate class as informed by the approved RRA at the time of the F2019 compliance filing.

149.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-49 to 6-50 and page 6-59

1.149.1 Assuming BC Hydro's rate increases for F2017 through F2019 match the rate caps set out on page 1-2, please provide a schedule that compares the LGS energy rates for F2017 to F2019 under BC Hydro's preferred option (per page 6-59) with the LRMC range for each of these years as set out in Table 2-6.

RESPONSE:

	Energy Rate of Proposed LGS Design (cents/kWh)	**Table 2-6 LRMC (Low – High) (cents/kWh)**
F2018	**5.56**	**9.65 – 11.35**
F2019	**5.72**	**9.84 – 11.58**

149.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-49 to 6-50 and page 6-59

1.149.2 At page 6-49 (lines 18-19) BC Hydro states that the improved changed (to 65% demand cost recovery from demand charges) "improves fairness and does so without a loss of efficiency". Please explain why there is no loss in efficiency when moving from 50% to 65% demand cost recovery via the demand charge decreases the energy rate (per Table 6-18) and moves it further away from the LRMC range.

RESPONSE:

BC Hydro is of the view that for the purpose of assessing whether a LGS flat energy rate is an economically efficient price signal in comparison to the energy LRMC, there is little difference between the F2017 forecast flat energy rate of 5.37 cents/kWh under its proposal (assuming 65 per cent demand cost recovery) and the alternative F2017 forecast flat energy rate of 5.98 cents/kWh (assuming 50 per cent demand cost recovery).

Please also refer also to BC Hydro's response to BCUC IR 1.75.1.

150.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-49 and 6-58

1.150.1 Based on the F2016 LGS billing determinants (i.e., customers, demand and energy) please provide the calculations demonstrating that the current F2016 demand charges recover 50% of demand-related costs. In doing so please indicate (with reference to the F2016 COSS – Appendix E) what the demand-related costs allocated to LGS are.

RESPONSE:

Forecast LGS demand revenue in F2016 equals $207 million. Total assigned LGS demand-related costs in the F2016 COS are $403.1 million, as computed in cell G7 of sheet 4.1 in the F2016 COS excel file attached to Appendix E of Exhibit B-1.

Dividing $207 million into $403.1 million equals 51 per cent, or approximately 50 per cent.

Please refer to section 6 of Appendix H-1A of Exhibit B-1 for forecast LGS billing determinants for F2017-F2019.

150.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-49 and 6-58

1.150.2 What percentage of the customer-related costs allocated to LGS are recovered though the basic charge? In responding, please indicate what the dollar value for customer-related costs is for the LGS class, providing the necessary cross-references to the F2016 COSS – per Appendix E.

RESPONSE:

Approximately 7 per cent of customer-related costs assigned to the LGS class are recovered through the basic charge.

The result is based on forecast F2017 LGS basic charge revenue of $0.57 million, as reported in Table H-1A-19 of Appendix H-1A of Exhibit B-1, *divided by* total customer-related costs assigned to the LGS class of $8.1 million, as computed in cell H7 of sheet 4.1 in the F2016 COS excel file attached to Appendix E of Exhibit B-1.

151.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, page 6-58

1.151.1 Page 6-58 indicates that for RS 1823 customers (i.e., Transmission Service customers), the demand charge recovers 65% of demand costs. How are demand cost for RS 1823 customers defined for purposes of this calculation? In particular, given there is no basic charge for RS 1823 customers, does the definition include the customer-related costs allocated to Transmission Service customers?

RESPONSE:

The customer-related costs are recovered in the RS 1823 energy charge.

The 65 per cent calculation for Transmission Service customers is based on about $196 million in demand charge revenue divided by demand-related costs of $303 million, which is found in Schedule 4.1 of the F2016 COS model, Appendix E of Exhibit B-1.

Customer-related costs associated with the transmission rate class are about $1.7 million (refer to Schedule 4.1 of the F2016 COS model, Appendix E of Exhibit B-1). If these were added to the demand-related costs when calculating the percentage of demand-related cost recovery the percentage would remain about 65 per cent (i.e., $196 million/($303 million + $1.7 million)).

151.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, page 6-58

1.151.2 Based on the F2016 billing determinants (i.e., customers, demand and energy) for Transmission service customers, please provide the calculations demonstrating that the current F2016 demand charge recovers 65% of demand-related costs. In doing so please indicate (with reference to the F2016 COSS – Appendix E) what the demand-related costs allocated to Transmission service customers are.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.151.1.

151.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, page 6-58

1.151.3 If customer-related costs are not include in the definition of "demand costs" used for purposes of calculating the 65%, please recalculate (similar to the response to part (2)) the percentage with customer-related costs included.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.151.1.

152.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, pages 19-22

1.152.1 Please provide a schedule similar to Table H-1A-19 (rows A-AE) but for F2016 based on the approved F2016 rates. Please reconcile the revenues that result with those used in the COSS (Schedule 4.0) for the LGS class.

RESPONSE:

The table below is reproduced from BC Hydro Compliance with Commission Order No. G-48-14, ORIGINAL FILED March 18, 2015 - ERRATA No. 1 INFORMALLY SUBMITTED on March 20, 2015, Attachment 3, section 2.6, Table 18.

Schedule 4.0 shows a target revenue of $815 million, which is comparable to line AF divided by (1 + Rate Rider of 5%) = $815 million.

Line	Description	Value	Unit
A	Forecast Part 1, Tier 1 Class Load	1,079,719,828	kWh
B	Forecast Part 1, Tier 2 Class Load	9,353,546,015	kWh
C	Forecast Part 2 LRMC Class Load	153,081,539	kWh
D	Forecast Part 2 Tier 2 Class Load	13,524,770	kWh
E	Forecast Minimum Energy Charge Class Load	16,187,218	kWh
F	Forecast Energy, LGS Class	10,616,059,370	kWh
G	Forecast Number of Accounts, LGS Class	6,223	
H	Forecast Class Demand Tier 1	2,591,112	kW
I	Forecast Class Demand Tier 2	7,586,686	KW
J	Forecast Class Demand Tier 3	16,317,148	kW
K	Tier 1 Energy Rate	10.66	cents/kWh
L	Tier 2 Energy Rate	5.13	cents/kWh
M	Part 2 LRMC Energy Rate	9.90	cents/kWh
N	Minimum Energy Charge	3.30	cents/kWh
O	Basic Charge	0.2257	$ / Day
P	Tier 1 Demand Rate	-	$/kW
Q	Tier 2 Demand Rate	5.50	$/kW
R	Tier 3 Demand Rate	10.55	$/kW
S	Forecast primary potential and transformation discounts	(9,784,956)	$
T	Tier 1 Energy Revenue	115,098,134	$
U	Tier 2 Energy Revenue	479,836,911	$
V	Part 2 LRMC Energy Revenue	15,155,072	$
W	Part 2 Tier 2 Energy Revenue	693,821	$
X	Minimum Energy Charge Revenue	534,178	$
Y	Tier 1 Demand Revenue	-	$
Z	Tier 2 Demand Revenue	41,726,773	$
AA	Tier 3 Demand Revenue	172,145,911	$
AB	Basic Charge Revenue	514,058	$
AC	TS No. 82 revenue effect	(488,161)	$
AD	Rate Rider (%)	5	%
AE	Total Forecasted Revenue (including rate rider)	856,203,328	$
AF	Target Revenue (including rate rider)	856,039,386	$
AG	Variance due to rates rounding	163,942	$
AH	Variance (%)	0.019	

153.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, page 26

1.153.1 Please indicate how the 1.3 escalation factor for the LGS demand charge cost recovery was determined.

RESPONSE:

The 1.3 = demand cost recovery of 65 per cent/current demand cost recovery of 50 per cent.

154.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, pages 26-30

For purposes of modelling BC Hydro has calculated the "proposed rates" for F2017-F2019 so as to be revenue neutral to revenues assuming the status quo LGS rates for each year (page 26). BC Hydro proposes to implement the LGS changes April 1, 2017.

1.154.1 How will the flat demand charge for F2018 be determined, assuming the F2018 RRA increase is 3.5%?

RESPONSE:

If the implementation of the LGS changes is April 1, 2017 (F2018) and assuming that the proposed LGS rate is approved, then the demand charge will be determined by escalating the F2017 target revenue to be collected from demand charge under the status quo rate structure by a factor that yields a demand-related cost recovery of 65 per cent, using the best available data at the time of the F2018 compliance filing.

The basic charge will be escalated by the RRA.

The Energy Charge will be determined to recover the target revenue as informed by the approved revenue requirement application at the time of the F2018 compliance filing.

154.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, pages 26-30

For purposes of modelling BC Hydro has calculated the "proposed rates" for F2017-F2019 so as to be revenue neutral to revenues assuming the status quo LGS rates for each year (page 26). BC Hydro proposes to implement the LGS changes April 1, 2017.

1.154.2 How will the F2018 energy charge be determined? Will it be determined so as to maintain revenue neutrality as if the status quo rate design had been maintained for F2018?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.154.1.

154.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, Appendix H-1A, pages 26-30

For purposes of modelling BC Hydro has calculated the "proposed rates" for F2017-F2019 so as to be revenue neutral to revenues assuming the status quo LGS rates for each year (page 26). BC Hydro proposes to implement the LGS changes April 1, 2017.

1.154.3 How will revenue neutrality be defined for F2019? Will it be based on: a) revenues for F2019 assuming the status quo rate design had been maintained through to F2018 and applying the RRA increases or b) determining the F2019 revenues using the LGS rates approved for F2018 and escalating the results by the RRA for F2019?

RESPONSE:

The target revenue for the LGS rate class as informed by the approved RRA at the time of the F2019 compliance filing.

155.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-65, 6-67 and 6-69

1.155.1 Please confirm that, based on Figure 6-12, the highest LGS bill impact shown (excluding RRA) is 4%. If not, what is the value?

RESPONSE:

As indicated on Exhibit B-1, page 6-64, line 17, the F2017 simulation shows that the maximum bill impact is 78 per cent if the proposed LGS flat rate is implemented in that year. The computation is based on F2015 customer data. The bill impact for subsequent years for all customers is modelled to be 3.5 per cent for F2018, and 3 per cent for F2019, assuming that the RRA increases equal the Direction No. 7 rate caps.

155.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-65, 6-67 and 6-69

1.155.2 Based on actual customer billing profiles: a) what is the maximum impact an LGS customer would see (including the F2018 RRA of 3.5%) and b) how many LGS customers will see a bill impact in excess of 10% (including the F2018 RRA of 3.5%)?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.155.1.

155.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-65, 6-67 and 6-69

1.155.3 Does BC Hydro agree that one of the factors affecting customer acceptance is bill impacts?

RESPONSE:

Yes.

155.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-65, 6-67 and 6-69

1.155.4 Please explain the difference between Figures 6-12 and 6-16. While the titles suggest both are showing the impacts of transitioning to BC Hydro's preferred LGS rate design in one year (6-12 net of the RRA and 6-16 including RRA), the differences between the values shown in the tables are more than the RRA increase for F2017.

RESPONSE:

Exhibit B-1, Figure 6-16 is bill impact including RRA, reproduced from Exhibit B-1, Appendix C-1B, page 75 (with the lower end of consumption adjusted down slightly to show higher impacts). It is simulated on the same vintage of assumptions as Workshop 12, so that it is comparable to the bill impacts of phase-in for Exhibit B-1, Figure 6-17.

Exhibit B-1, Figure 6-12 is bill impact less RRA, simulated on the assumptions as stated in Exhibit B-1, Appendix H-1A, which is the latest available at the time of the Application.

If the RRA is removed from Figure 6-16, the outcome is Figure 6-6 and there is similar overall direction and patterns, and minor differences in the magnitude of the impacts. The minor differences would be attributable to the different vintage of assumptions.

156.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 6-70 to 6-71

1.156.1 Given the currently existing "new" LGS and MGS customers and assuming an addition of new customers for November 15, 2015 through March 31, 2016 matching that experienced in the period November 15, 2014 through March 31, 2015, what would be the impact on BC Hydro's F2016 net income of the requested change in the new account rule for LGS and MGS customers effective January 1, 2016?

RESPONSE:

There would be no impact to BC Hydro's net income. Variances between actual and planned revenue are deferred to the Non-Heritage Deferral Account, which is recovered through the DARR.

Note that pursuant to Commission Order No. G-175-15 (Exhibit A-4), the Commission stated that it would render an order with respect to the new account 85/15 Pricing on or before February 10, 2016.

157.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1 page 6-74

1.157.1 Does BC Hydro plan/construct either transmission or distribution facilities to provide service under RS 1253?

RESPONSE:

No, BC Hydro does not plan/construct either transmission or distribution facilities to provide service under RS 1253. Electricity service under RS 1253 is on an interruptible basis and BC Hydro supplies electricity only to the extent it has energy and capacity to do so.

157.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1 page 6-74

1.157.1 Does BC Hydro plan/construct either transmission or distribution facilities to provide service under RS 1253?

1.157.1.1 If yes, who pays for these facilities?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.157.1.

157.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1 page 6-74

1.157.1 Does BC Hydro plan/construct either transmission or distribution facilities to provide service under RS 1253?

1.157.1.2 If no, is RS 1253 service denied when there are insufficient existing transmission and/or distribution facilities to deliver the requested service?

RESPONSE:

Yes.

157.0 CHAPTER 6 GENERAL SERVICE RATE DESIGN

Reference: Exhibit B-1 page 6-74

1.157.2 How are RS1253 loads and revenues treated in the COSS?

RESPONSE:

Depending on the size of the customer, loads and revenues are included in either the MGS or LGS rate classes. Total RS 1253 revenue is estimated to be about $25,000.

158.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-7

1.158.1 Does the BCUC have the jurisdiction to determine what the appropriate LRMC value is for purposes of setting the Tier 2 rate?

RESPONSE:

Yes.

158.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-7

1.158.2 Does the BCUC have the jurisdiction to alter the percentage of demand-related costs that are recovered through the demand charge?

RESPONSE:

Yes, provided that the RS 1823 Tier 2 rate does not fall below the lower end of the energy LRMC. Please refer to Exhibit B-1, page 7-8, line 5 and page 7-16, lines 10 to 15.

159.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-8 to 7-9

1.159.1 The Application states that a choice between revenue neutrality definitions must be made for F2017 but is not necessary for F2018 or F2019. Will the choice of revenue neutrality definition for F2017 affect the level of revenue that will be recovered from Transmission Service customers in F2017 – for a given level of RRA increase?

RESPONSE:

Yes.

159.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-8 to 7-9

1.159.1 The Application states that a choice between revenue neutrality definitions must be made for F2017 but is not necessary for F2018 or F2019. Will the choice of revenue neutrality definition for F2017 affect the level of revenue that will be recovered from Transmission Service customers in F2017 – for a given level of RRA increase?

1.159.1.1 If not, please explain why and demonstrate with supporting calculations.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.159.1.

159.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-8 to 7-9

1.159.2 If yes, does this mean that the definition of revenue neutrality used for Transmission Service customers could affect the level of the overall RRA increase required in F2017 (assuming the level of RRA increase is established in order to provide a certain level of revenue requirement in F2017)?

RESPONSE:

No, it does not mean that the definition of revenue neutrality used for RS 1823 customers could affect the level of the overall RRA increase required in F2017. The RRA increase is only set once and determines the revenue target. BC Hydro does not re-determine the RRA increase to account for any forecasted revenue shortfall from rates.

159.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-8 to 7-9

1.159.2 If yes, does this mean that the definition of revenue neutrality used for Transmission Service customers could affect the level of the overall RRA increase required in F2017 (assuming the level of RRA increase is established in order to provide a certain level of revenue requirement in F2017)?

1.159.2.1 If not, please explain why and demonstrate with supporting calculations.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IRs 1.159.2, 1.160.3 and 1.160.4.

159.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-8 to 7-9

1.159.3 The Application states that a choice between revenue neutrality definitions must be made for F2017 but is not necessary for F2018 or F2019. Will the choice of revenue neutrality definitions for F2017 affect the level of revenue to be that will be recovered from Transmission Service customers in F2018 and F2019 – for a given level of RRA increase?

RESPONSE:

Yes. Please refer to BC Hydro's response to BCOAPO IR 1.160.4.

159.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-8 to 7-9

1.159.3 The Application states that a choice between revenue neutrality definitions must be made for F2017 but is not necessary for F2018 or F2019. Will the choice of revenue neutrality definitions for F2017 affect the level of revenue to be that will be recovered from Transmission Service customers in F2018 and F2019 – for a given level of RRA increase?

1.159.3.1 If not, please explain why and demonstrate with supporting calculations.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.160.4.

159.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-8 to 7-9

1.159.4 If yes, does this mean that the definition of revenue neutrality used for Transmission Service customers in F2017 could affect the level of the overall RRA increase required in each of F2018 and F2019 (assuming the RRA increase is established in order to provide certain levels of revenue requirements in F2018 and F2019)?

RESPONSE:

No, the definition of revenue neutrality used for RS 1823 customers in F2017 does not affect the level of the overall RRA increase in each of F2018 and F2019. The RRA increases in F2018 and F2019 are only determined once and do not account for any revenue shortfall in F2017 due to the use of bill neutrality in determining F2017 rates.

159.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-8 to 7-9

1.159.4 If yes, does this mean that the definition of revenue neutrality used for Transmission Service customers in F2017 could affect the level of the overall RRA increase required in each of F2018 and F2019 (assuming the RRA increase is established in order to provide certain levels of revenue requirements in F2018 and F2019)?

1.159.4.1 If not, please explain why and demonstrate with supporting calculations.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IRs 1.159.4, 1.160.3 and 1.160.4.

159.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-8 to 7-9

1.159.5 Please confirm that the conclusion (page 7-9, lines 2-5) that the "RRA increases thereafter will result in RS 1823 pricing that in F2019 and F2019 satisfies all the requirements of Direction No. 7" is based on the assumption that the RRA increases will be equal to or exceed inflation.

RESPONSE:

Confirmed. The conclusion is based on the assumption that the RRA increase is 3.5 per cent in F2018 and 3 per cent in F2019, which both exceed BC Hydro's assumed inflation rate of 2 per cent.

160.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-9 to 7-10; pages 7-12 to 7-13 and Appendix H-1A

1.160.1 Please provide the forecast Transmission Service billing quantities (e.g. demand, Tier 1 energy, Tier 2 energy) for F2016 as used in the COSS.

RESPONSE:

The F2016 COS study does not use individual billing demands from customers in the Transmission Service rate class. Rather, an overall coincident load profile for the class was used in the determination of the 4 CP allocator.

Forecast F2016 RS 1823 Tier 1 and Tier 2 F2016 energy is used in the F2016 COS study and these quantities are found in BC Hydro's response to AMPC IR 1.10.1.

160.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-9 to 7-10; pages 7-12 to 7-13 and Appendix H-1A

1.160.2 Please provide a schedule setting out the calculation of the F2016 revenue for the transmission service class as presented in Appendix E, COSS Tab 4.0 ($889.32 M).

RESPONSE:

The F2016 revenue from the Transmission Service rate class is found on Schedule 14.0 of the F2015-F2016 RRA. It is the sum of revenue from:

	F2016 revenue from the Transmission Service Rate Class ($ million)
New Westminster	27
FortisBC	36
Other Transmission Customers	826
Total	889

160.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-9 to 7-10; pages 7-12 to 7-13 and Appendix H-1A

1.160.3 Please provide the derivation of the F2017, F2018 and F2019 revenues at F2016 Transmission Service rates and what the resulting revenue targets would be for F2017-F2020 using the RRA increases per Appendix H-1A (page 2).

RESPONSE:

The table below shows the estimated revenues at F2016 rates and the estimated revenue targets using the RRA increases per Appendix H-1A for F2017, F2018 and F2019. The BC Hydro October 2014 Load Forecast of RS 1823 Tier 1 and Tier 2 load is used. Note that BC Hydro has not provided a revenue target for F2020 as this is beyond the period for which BC Hydro is seeking approval of RS 1823 pricing principles.

The formula for the revenue target in each year is as follows:

F2017 Revenue Target = F2016 Tariff Rate x F17 forecast Load x F2017 RRA Increase

F2018 Revenue Target = F2016 Tariff Rate x F2018 forecast Load x F2017 RRA Increase x F2018 RRA Increase

F2019 Revenue Target = F2016 Tariff Rate x F2019 forecast Load x F2017 RRA Increase x F2018 RRA Increase x F2019 RRA Increase

October F2014 Load Forecast		**F2017**	**F2018**	**F2019**
RS 1823 Stepped Rate Load (GWh)				
Tier 1		10,374	10,286	9,629
Tier 2		491	516	441
		10,865	10,802	10,070
	F2016			
Rate ($/MWh)				
Tier 1	38.36			
Tier 2	85.03			
Revenue Target				
		Revenue		
		F2017	**F2018**	**F2019**
Revenue at F2016 Rates ($ million)		439.7	438.4	406.9
Rate Increase (%)		4.0	3.5	3.0
Revenue Target ($ million)		457.3	471.9	451.1

160.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-9 to 7-10; pages 7-12 to 7-13 and Appendix H-1A

1.160.4 Please provide the derivation of the F2017 revenues to be recovered from Transmission Service customers using the bill neutrality definition of revenue neutrality and an F2017 RRA increase of 4% under each of the three Options.

RESPONSE:

The following table shows the rates for the three RS 1823 pricing principle options shown in Table 7-3 of Exhibit B-1, the resulting forecast revenues and the resulting under/over recovery of revenue compared to the revenue targets calculated in BC Hydro's response to BCOAPO IR 1.160.3. Please note that these estimates replace the revenue impacts of the three options reported in section 7.2.3.1, page 7-13 of Exhibit B-1 and in Attachment 4 to the Workshop 5 consideration memo. The earlier analysis did not use the same rates as in Table 7-3 of Exhibit B-1 or the October 2014 Load Forecast for the Tier 1 and Tier 2 forecast loads.

The results for Option 1 in the table below show that the under recovery of revenue in F2017 due to the bill neutrality definition persists in F2018 and F2019. This is because the rates are only escalated by the RRA increase in F2018 and F2019 and do not account for the shortfall in revenue in F2017. Thus, footnote 262 on page 7-13 is incorrect in stating that "BC Hydro reported for Option 1 under recoveries of $2.3 million and $2.4 million for F2018 and F2019 respectively. However, this wrongly assumed that an under-recovery in one year continues through in future years and this is not true in the case when forecast revenue neutrality is satisfied as in F2018 and F2019."

Option 1			
Rate ($/MWh)	**F2017**	**F2018**	**F2019**
Tier 1	39.81	41.21	42.44
Tier 2	89.20	92.32	95.09
Revenues ($ million)			
Tier 1	413.0	423.9	408.7
Tier 2	43.8	47.6	41.9
Total Revenues	**456.8**	**471.5**	**450.6**
Over/(Under) Recovery	-0.5	-0.4	-0.5

Option 2			
Rate ($/MWh)			
Tier 1	39.81	41.35	42.70
Tier 2	89.20	91.00	92.80
Revenues ($ million)			
Tier 1	413.0	425.3	411.2
Tier 2	43.8	47.0	40.9
Total Revenues	**456.8**	**472.3**	**452.1**
Over/(Under) Recovery	-0.5	0.3	1.0
Option 3			
Rate ($/MWh)			
Tier 1	38.36	39.56	40.87
Tier 2	102.27	107.10	109.20
Revenues ($ million)			
Tier 1	397.9	406.9	393.5
Tier 2	50.2	55.3	48.2
Total Revenues	**448.2**	**462.2**	**441.7**
Over/(Under) Recovery	-9.1	-9.8	-9.4

160.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-9 to 7-10; pages 7-12 to 7-13 and Appendix H-1A

1.160.5 Please provide (using schedules similar to those employed for the MGS and LGS classes in Appendix H-1A), the derivation of the F2017-F2020 rates presented for each of the Options in Table 7-3.

RESPONSE:

The derivation for each of the Options is as follows:

<u>Option 1</u>

F2017

Tier 2 Rate = lower bound of LRMC

Tier 1 Rate = (RS 1823A – 0.1 x Tier 2 Rate)/0.9

F2018

Tier 2 Rate = F2017 Tier 2 Rate x F2018 RRA increase

Tier 1 Rate = (RS 1823A – 0.1 x Tier 2 Rate)/0.9

F2019

Tier 2 Rate = F2018 Tier 2 Rate x F2019 RRA increase

Tier 1 Rate = (RS 1823A – 0.1 x Tier 2 Rate)/0.9

<u>Option 2</u>

F2017-F2019

Tier 2 Rate = lower bound of LRMC

Tier 1 Rate = (RS 1823A – 0.1 x Tier 2 Rate)/0.9

<u>Option 3</u>

F2017

Tier 1 Rate = F2016 Tier 1 Rate

Tier 2 Rate = (RS 1823A – 0.9 x Tier 1 Rate)/0.1

F2018 and F2019

Tier 2 Rate = upper bound of LRMC

Tier 1 Rate = (RS 1823A – 0.1 x Tier 2 Rate)/0.9

The table below shows the information used to derive the F2017-F2019 rates presented for each of the Options in Table 7-3 of Exhibit B-1.

	F2016	F2017	F2018	F2019
RRA Increase (%)		**4.0**	**3.5**	**3.0**
RS 1823A	**43.03**	**44.75**	**46.32**	**47.71**
LRMC ($/MWh)				
Lower	**90.20**	**89.20**	**91.00**	**92.80**
Upper	**106.10**	**105.00**	**107.10**	**109.20**
Option 1 ($/MWh)				
Tier 1	**38.36**	**39.81**	**41.21**	**42.44**
Tier 2	**85.03**	**89.20**	**92.32**	**95.09**
Option 2 ($/MWh)				
Tier 1	**38.36**	**39.81**	**41.35**	**42.70**
Tier 2	**85.03**	**89.20**	**91.00**	**92.80**
Option 3 ($/MWh)				
Tier 1	**38.36**	**38.36**	**39.56**	**40.87**
Tier 2	**85.03**	**102.27**	**107.10**	**109.20**

160.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-9 to 7-10; pages 7-12 to 7-13 and Appendix H-1A

1.160.6 Please provide the derivation of the F2017 revenues to be recovered from Transmission Service customers using the forecast revenue neutral definition of revenue neutrality and an F2017 RRA increase of 4%.

RESPONSE:

Please refer to the F2017 revenue target estimated in BC Hydro's response to BCOAPO IR 1.160.3.

160.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-9 to 7-10; pages 7-12 to 7-13 and Appendix H-1A

1.160.7 Please provide a schedule similar to Table 7-3 that sets out the Transmission service rates and resulting revenues for each of the options for F2017-F2020 assuming a forecast revenue neutral definition of revenue neutrality is used for F2017.

RESPONSE:

The following provides a schedule similar to Table 7-3 of Exhibit B-1 that sets out the Transmission Service rates and resulting revenues for each of the options for F2017-F2019 assuming a forecast revenue neutral definition of revenue neutrality is used for F2017. Note that BC Hydro has not provided the rates and resulting revenues for F2020 as this is beyond the period for which BC Hydro is seeking approval of RS 1823 pricing principles.

Revenue Target	Revenues		
	F2017	F2018	F2019
Revenue at F2016 Rates	439.7	438.4	406.9
RRA Increase (%)	4.0	3.5	3.0
Revenue Target	457.3	471.9	451.1
Option 1 Rate ($/MWh)			
Tier 1	39.86	41.25	42.49
Tier 2	89.20	92.32	95.09
Revenues ($ million)			
Tier 1	413.5	424.3	409.1
Tier 2	43.8	47.6	41.9
Total Revenues	457.3	472.0	451.1
Over/(Under) Recovery	0.0	0.0	0.0
Option 2 Rate ($/MWh)			
Tier 1	39.86	41.35	42.70
Tier 2	89.20	91.00	92.80
Revenues ($ million)			
Tier 1	413.5	425.3	411.2
Tier 2	43.8	47.0	40.9
Total Revenues	457.3	472.3	452.1

Revenue Target	**Revenues**		
	F2017	**F2018**	**F2019**
Over/(Under) Recovery	**0.0**	**0.3**	**1.0**
Option 3 Rate ($/ MWh)			
Tier 1	**39.24**	**39.56**	**40.87**
Tier 2	**102.27**	**107.10**	**109.20**
Revenues ($ million)			
Tier 1	**407.0**	**406.9**	**393.5**
Tier 2	**50.2**	**55.3**	**48.2**
Total Revenues	**457.3**	**462.2**	**441.7**
Over/(Under) Recovery	**0.0**	**-9.8**	**-9.4**

160.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-9 to 7-10; pages 7-12 to 7-13 and Appendix H-1A

1.160.7 Please provide a schedule similar to Table 7-3 that sets out the Transmission service rates and resulting revenues for each of the options for F2017-F2020 assuming a forecast revenue neutral definition of revenue neutrality is used for F2017.

1.160.7.1 As part of the response, please provide (using schedules similar to those employed for the MGS and LGS classes in Appendix H-1A), the derivation of the F2017-F2020 rates presented for each of the Options using the forecast revenue neutral definition of revenue neutrality.

RESPONSE:

The following table shows the derivation of the F2017-F2019 rates presented for each of the Options using the forecast revenue neutral definition of revenue neutrality. Note that BC Hydro has not provided the rates and resulting revenues for F2020 as this is beyond the period for which BC Hydro is seeking approval RS 1823 pricing principles.

Revenue Target	**Revenues**		
	F2017	**F2018**	**F2019**
Revenue at F2016 Rates	**439.7**	**438.4**	**406.9**
RRA Increase (%)	**4.0**	**3.5**	**3.0**
Revenue Target	**457.3**	**471.9**	**451.1**
Option 1 Rate ($/MWh)			
Tier 1	**39.86**	**41.25**	**42.49**
Tier 2	**89.20**	**92.32**	**95.09**
Revenues ($ million)			
Tier 1	**413.5**	**424.3**	**409.1**
Tier 2	**43.8**	**47.6**	**41.9**
Total Revenues	**457.3**	**472.0**	**451.1**
Over/(Under) Recovery	**0.0**	**0.0**	**0.0**
Option 2 Rate ($/MWh)			
Tier 1	**39.86**	**41.32**	**42.60**

Revenue Target	**Revenues**		
	F2017	**F2018**	**F2019**
Tier 2	**89.20**	**91.00**	**92.80**
Revenues ($ million)			
Tier 1	**413.5**	**425.0**	**410.2**
Tier 2	**43.8**	**47.0**	**40.9**
Total Revenues	**457.3**	**472.0**	**451.1**
Over/(Under) Recovery	**0.0**	**0.0**	**0.0**
Option 3 Rate ($/MWh)			
Tier 1	**39.24**	**40.51**	**41.85**
Tier 2	**102.27**	**107.10**	**109.20**
Revenues ($ million)			
Tier 1	**407.0**	**416.7**	**402.9**
Tier 2	**50.2**	**55.3**	**48.2**
Total Revenues	**457.3**	**472.0**	**451.1**
Over/(Under) Recovery	**0.0**	**0.0**	**0.0**

161.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-13

1.161.1 Please provide the calculations supporting the impacts reported at lines 15-19, showing the calculation of the revenues using the different approaches and the resulting differences as reported.

RESPONSE:

The following shows the assumptions and calculations supporting the rates and the resulting impacts reported at lines 15 to 19, Exhibit B-1, page 7-13. These were originally reported in Attachment 4 to the Workshop 5 consideration memo, at Attachment C-5A of Exhibit B-1.

The derivation of the rates for each of the Options is the same as that reported in BC Hydro's response to BCOAPO IR 1.160.5. However, the LRMC values differ as shown in the following table.

	F2016	F2017	F2018	F2019
RRA Increase (%)		4.0	3.5	3.0
RS 1823A	43.03	44.75	46.32	47.71
LRMC				
Lower		92.00	93.80	95.70
Upper		108.20	110.40	112.60
Option 1 ($/MWh)				
Tier 1	38.36	39.50	40.88	42.11
Tier 2	85.03	92.00	95.22	98.08
Option 2 ($/MWh)				
Tier 1	38.36	39.50	41.04	42.37
Tier 2	85.03	92.00	93.80	95.70
Option 3 ($/MWh)				
Tier 1	38.36	38.36	39.20	40.50
Tier 2	85.03	102.27	110.40	112.60

In addition, the revenue target was calculated on a different basis i.e., F2015 forecast load was used multiplied by F2016 rates and escalated by the cumulative RRA increases for each forecast year.

	F2015		
Tier 1	10,073		
Tier 2	480		
	10,553		
Revenues			
	F2017	F2018	F2019
Revenue at F2016 Rates	427.2	427.2	427.2
Rate Increase (%)	4.0	3.5	3.0
Adjusted Revenues	444.3	459.8	473.6
Option 1 Rate ($/MWh)			
Tier 1	39.50	40.88	42.11
Tier 2	92.00	95.22	98.08
Revenues ($ million)			
Tier 1	397.9	411.8	424.2
Tier 2	44.2	45.7	47.1
Total Revenues	442.0	457.5	471.2
Over/(Under) Recovery	-2.2	-2.3	-2.4
Option 2 Rate ($/MWh)			
Tier 1	39.50	41.04	42.37
Tier 2	92.00	93.80	95.70
Revenues ($ million)			
Tier 1	397.9	413.4	426.8
Tier 2	44.2	45.0	45.9
Total Revenues	442.0	458.4	472.7
Over/(Under) Recovery	-2.2	-1.4	-0.9
Option 3 Rate ($/MWh)			
Tier 1	38.36	39.20	40.50
Tier 2	102.27	110.40	112.60
Revenues ($ million)			
Tier 1	386.4	394.8	407.9
Tier 2	49.1	53.0	54.0
Total Revenues	435.5	447.8	461.9
Over/(Under) Recovery	-8.8	-12.0	-11.7

162.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-14

1.162.1 Given that the use of the bill neutrality definition of revenue neutrality for the Transmission Service alters the F2017 revenues, couldn't this approach be viewed as implicitly rebalancing the revenue allocation between the customer classes?

RESPONSE:

No. Please refer to BC Hydro's response to CEC IR 1.73.1.

162.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-14

1.162.1 Given that the use of the bill neutrality definition of revenue neutrality for the Transmission Service alters the F2017 revenues, couldn't this approach be viewed as implicitly rebalancing the revenue allocation between the customer classes?

1.162.1.1 If not, why not?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.73.1.

163.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-21

1.163.1 Why is the difference in Mid-C monthly prices used to shape the Tier 2 rate for each season when the Tier 2 rates itself is based on LRMC and not short-term market prices?

RESPONSE:

The Tier 2 rate is a proxy for LRMC and prior to the 2015 RDA reflected the price from longer term contracts based on previous calls for tender (CFT). The Mid C price shape is used since it is the closest market hub and has been used in previous rate designs to provide a market based price signal which also reflects BC Hydro's short-term opportunity cost.

However, BC Hydro does not use a short term price shape for RS 1825. The long-term 20-year forecast Mid C monthly price shape was used to shape the RS 1825 Tier 2 rate since the Tier 2 rate is longer-term and the price shape and price should match the longer CFT contract terms.

The Mid C market forward prices represent current expectations of electricity supply/demand. These prices and the yearly price shapes are variable, as they represent price expectations over the short-term. The yearly price shape as derived from short-term forecasts will contain significant excursions from expected averages due to temporary market and supply/demand conditions.

BC Hydro considers that a more representative yearly shape is that derived from a long-term forecast.

164.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-22 to 7-23

1.164.1 Is BC Hydro proposing any restrictions as to how frequently it can alter the RS 1852 definition of HLH or how much notice customers will be given of a planned change?

RESPONSE:

No, BC Hydro is not proposing any restrictions as to how frequently it can alter the definition of HLH or any related customer notification.

The definition of HLH referred to in RS 1852 is defined in the customer's Modified Demand Agreement (TS 54) and is not changed over the one year term of each agreement. The customer has to agree to the terms of the agreement on an annual basis upon re-subscription. Given this arrangement, BC Hydro's view is that there is no need for such restrictions.

165.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1. pages 7-25 to 7-26

1.165.1 Please explain more fully why an RTP option would result in non-firm service for incremental demand above the CBL.

RESPONSE:

By offering a RTP rate with non-firm service above a CBL, BC Hydro does not include customer load above the CBL in its load forecasts and therefore it will not acquire or advance resources to serve that load.

Consequently, customers can be offered Mid C market-based rates at prices significantly less than BC Hydro's costs to supply incremental firm load. However, there are barriers and challenges with RTP rates (refer to section 2.4 of the Workshop 5 consideration memo, pages 127 to 130 of 292, Appendix C-5A of Exhibit B-1).

166.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-27 to 7-29

1.166.1 Given the potential variation in spring water flows, what is the likelihood that there will be spills in F2017-F2020, assuming no freshet rate is offered?

RESPONSE:

BC Hydro spills from some reservoirs in its system every year as required to maintain reservoirs within elevation limits and to provide required downstream flows. Spills from system storage occur infrequently.

The primary goal of the freshet rate is to provide flexibility to reduce surplus exports (or increase imports) across the freshet, thus leaving the operation of power plants within the province largely unchanged. Any additional marginal reduction in the volume of spill from system storage would have negligible impact on the frequency of spills from system storage.

166.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-27 to 7-29

1.166.2 With respect to Figure 7-2, given the export capability of BC Hydro's current interties, is the system physically able to "export" the surplus shown as it occurs or would there still be "surplus"?

RESPONSE:

In most water years, BC Hydro would be physically able to export the surplus. However, in years where large basins are at/near spilling, there would be motivation to run the power plants at high generation levels. This generation, coupled with the anticipated generation from run-of-river resources in the province, may exceed the export capability of the B.C.-U.S. intertie.

166.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-27 to 7-29

1.166.3 With respect to Figure 7-2, based on anticipated reservoir levels at the start of F2017, would BC Hydro be able to "store" the surplus identified in part (2) and, if not, what would be the anticipated amount spilled?

RESPONSE:

The BC Hydro system is not expected to be capable of storing the large volume of surplus shown on Figure 7-2 of Exhibit B-1. However, the issue is not related to available reservoir storage space at the two large storage reservoirs. It is due to the intensity of delivery of energy in the May through July period within the BC Hydro system. Across this period, minimum generation (the combination of non-dispatchable IPP resources, BC Hydro non-discretionary generation, and BC Hydro large basin storage operating at minimum loading levels) is expected to exceed the system load. As such, there would be a requirement to either export or spill the surplus energy. Please refer to BC Hydro's response to BCUC IR 1.113.1.1.

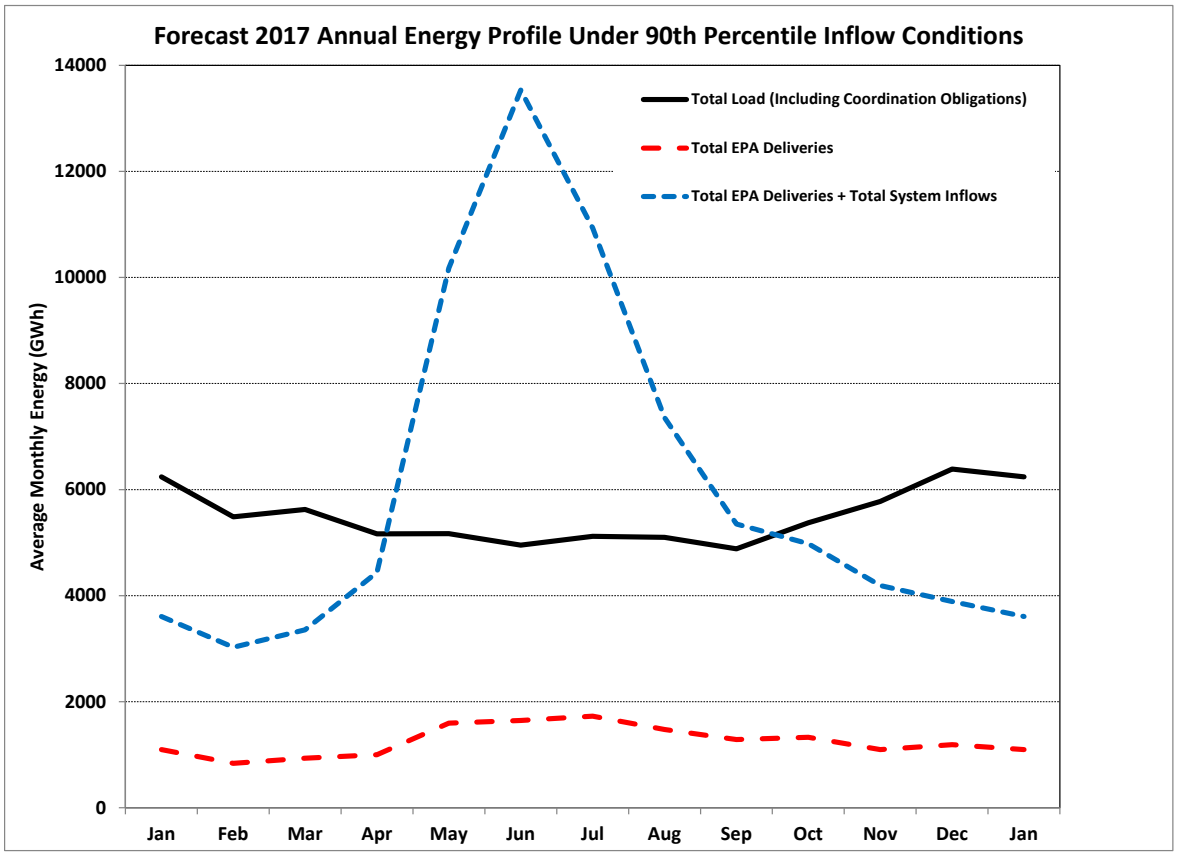
166.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-27 to 7-29

1.166.4 If practical please re-do Figure 7-2 assuming water flows at a P90 level for F2017 (i.e., water flows would only be higher 10% of the time) and provide responses to parts (2) and (3) assuming these conditions.

RESPONSE:

The requested figure is provided below while the commentary on impact of high inflows is included in BC Hydro's response to BCOAPO IRs 1.166.2 and 1.166.3.



167.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-29 to 7-32

At page 7-30 the Application states:

"At Workshop 10, BC Hydro pointed out that average August prices over the 2010 to 2014 period are noticeably higher than May to July prices and that differentials between HLH and LLH periods have generally averaged about $15/MWh during the freshet compared to about $5/MWh during other times of the year. This price spread indicates there may be greater incentive for customers to shift load from HLH to LLH during the freshet period relative to other times of the year (provided they have the ability to do so)."

1.167.1 Which "customers" is BC Hydro referring to given that the current RS 1823 provides no incentive from customers to shift from HLH to LLH?

RESPONSE:

BC Hydro is referring to RS 1823 customers, which are the only customers eligible for the freshet rate pilot. Please refer to the availability clause in the RS 1892 rate schedule found in Appendix F1-B of Exhibit B-1.

The statement in the question that the current RS 1823 provides no incentive for customers to shift from HLH to LLH is incorrect. RS 1823 provides an incentive to shift load from HLH to LLH since the peak kVA demand referent under RS 1823 for each Billing Period is only calculated during HLH.

In section 7.3.4.2 of Exhibit B-1, BC Hydro noted that there is a greater differential between HLH and LLH prices during the freshet period (about $15/MWh) than during other times of the year (about $5/MWh). All else being equal, this means that the prospective value to the RS 1823 customer of increasing load during the freshet period would be greater during LLH than HLH. Sophisticated RS 1823 customers with discrete load control capabilities (such as electrochemical plants, thermo-mechanical pulp mills, and customers with non-contracted self-generation) might have the ability to shift some portion of load between HLH and LLH during the freshet period.

167.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-29 to 7-32

At page 7-30 the Application states:

"At Workshop 10, BC Hydro pointed out that average August prices over the 2010 to 2014 period are noticeably higher than May to July prices and that differentials between HLH and LLH periods have generally averaged about $15/MWh during the freshet compared to about $5/MWh during other times of the year. This price spread indicates there may be greater incentive for customers to shift load from HLH to LLH during the freshet period relative to other times of the year (provided they have the ability to do so)."

1.167.2 Is Figure 7-4 calculated based solely on Mid-C prices or were the prices adjusted to incorporate the wheeling fee and price floor as proposed at page 7-37.

RESPONSE:

Figures 7-4 and 7-5 of Exhibit B-1 were developed using the differential between the Mid C price in Canadian dollars and the Tier 1 rate, without any wheeling fee or price floor.

167.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-29 to 7-32

At page 7-30 the Application states:

"At Workshop 10, BC Hydro pointed out that average August prices over the 2010 to 2014 period are noticeably higher than May to July prices and that differentials between HLH and LLH periods have generally averaged about $15/MWh during the freshet compared to about $5/MWh during other times of the year. This price spread indicates there may be greater incentive for customers to shift load from HLH to LLH during the freshet period relative to other times of the year (provided they have the ability to do so)."

1.167.2 Is Figure 7-4 calculated based solely on Mid-C prices or were the prices adjusted to incorporate the wheeling fee and price floor as proposed at page 7-37.

1.167.2.1 If the wheeling fee and price floor were not used in the determination of Figure 7-4, please provide a revised figure after these two elements have also been taken into account.

RESPONSE:

BC Hydro provides revised versions of Figures 7-4 and 7-5 of Exhibit B-1 below. These reflect both the wheeling fee and the price floor. Note that the price floor primarily impacts LLH periods.

Figure 7-4 HLH Differential between Tier 1 and $CDN Mid-C Price (Revised)

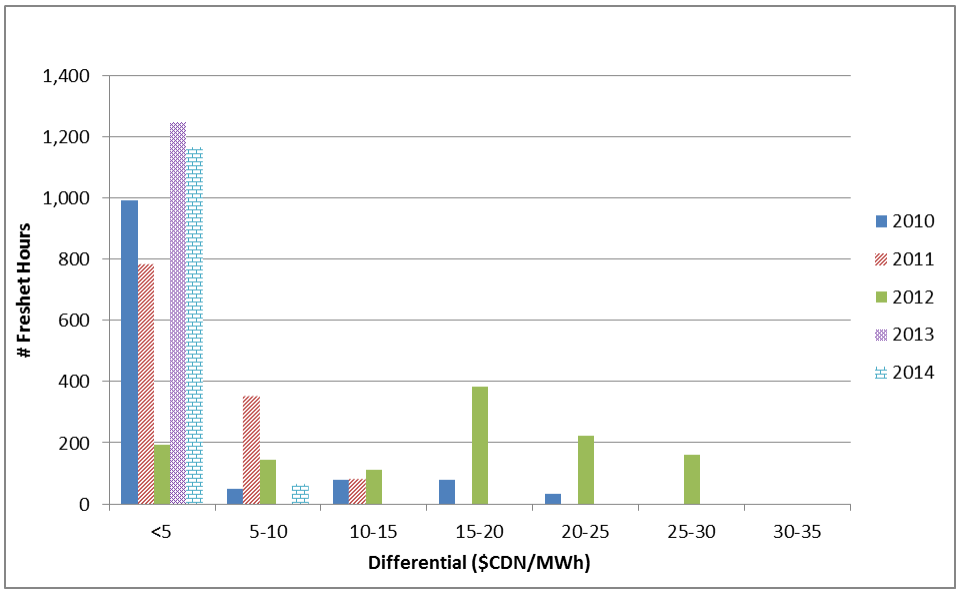
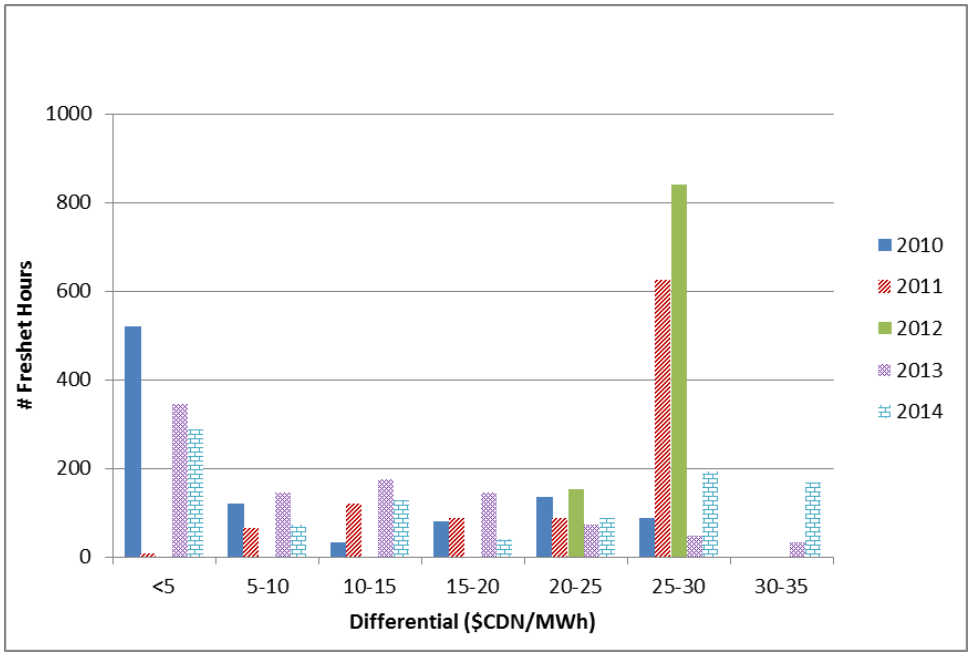


Figure 7-5 LLH Differential between Tier 1 and $CDN Mid-C Price (Revised)



168.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-32 to 7-34

1.168.1 Please describe what BC Hydro's "fairness concerns" are regarding offering (indirectly) residential customers of UBC, SFU and New Westminster market priced energy (per page 7-33).

RESPONSE:

As noted in BC Hydro's response to BCUC IR 1.110.3, natural load growth from BC Hydro's RS 1827 customers (including UBC, SFU and New Westinster), has been factored into BC Hydro's load forecasts and resource acquisitions. Accordingly, BC Hydro considers that it would be unfair for RS 1827 customers to benefit from the freshet rate in the absence of behavioural change. The concern is that such customers would purchase the same volume of electricity during the freshet period, but at a lower (market) price. In contrast, RS 1823 customers would need to change behaviour to receive a benefit.

In addition, BC Hydro considers that New Westminster, UBC and SFU's residential customers should not have access to market priced energy unless BC Hydro's own Residential customers have the same opportunity.

168.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, pages 7-32 to 7-34

1.168.2 With respect to billing, will there be any interest accumulated on the bill in recognition of the fact that RS 1892 usage in May through July will billed retroactively in August?

RESPONSE:

BC Hydro made the decision to bill RS 1892 energy in August because that is when the final incremental consumption and Net-to-Gross ratios can be determined. BC Hydro considered issuing bills for each of the three freshet months but decided this would require rebilling at the end of the period which adds administrative complexity for customers and BC Hydro.

Using the five aMW to 30 aMW take-up range for the rate, an average market price of CDN $30/MWh, an assumed 5 per cent interest rate and an assumed 45-day average payment delay, BC Hydro estimates foregone interest related revenue would range between $2,000 and $12,000. BC Hydro believes the any forgone interest revenue is offset by the administration costs avoided from issuing a single invoice at the end of the freshet period.

169.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-35

1.169.1 Is it BC Hydro's expectation that the maximum kW purchased under RS 1823 and RS 1892 will be less than the customer's (existing) contract demand?

RESPONSE:

ESA contract demands for RS 1823 customers most likely to use the freshet rate (such as electrochemical producers and thermo-mechanical pulp mills) are higher than the customer's existing peak demand. BC Hydro expects the customer's peak demand, including any incremental load under the freshet rate, to remain below its ESA contract demand.

169.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-35

1.169.1 Is it BC Hydro's expectation that the maximum kW purchased under RS 1823 and RS 1892 will be less than the customer's (existing) contract demand?

1.169.1.1 If it does exceed the contract demand for any of the months May through July, what (if any) additional charges will apply?

RESPONSE:

No additional charges would apply since the freshet rate pilot is a non-firm service. The situation would be similar to RS 1823 customers taking non-firm service under RS 1880, whereby BC Hydro retains the right to curtail the customer's incremental load if it is unable to supply the incremental energy or capacity.

169.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-35

1.169.2 Will a customer be permitted to temporarily increase its contract demand for the duration of the RS 1892 pilot?

RESPONSE:

Since the freshet rate reflects non-firm service, there is no need for a customer to temporarily increase their contract demand. Please also refer to BC Hydro's response to BCOAPO IR 1.169.1.1.

169.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-35

1.169.3 If the Net to Gross ratio is less than 100%, will there be any additional demand charges for load taken in excess of the Reference Demand?

RESPONSE:

The Net-to-Gross ratio is a component of the energy billing formula used to determine the proportion of hourly incremental freshet energy that will be billed under RS 1823 or RS 1892. It is unrelated to the customer's demand or the need for demand charges.

169.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-35

1.169.3 If the Net to Gross ratio is less than 100%, will there be any additional demand charges for load taken in excess of the Reference Demand?

1.169.3.1 If not, why not?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.169.3.

169.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-35

1.169.3 If the Net to Gross ratio is less than 100%, will there be any additional demand charges for load taken in excess of the Reference Demand?

1.169.3.2 If yes, how will they be determined?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.169.3.

170.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-38

1.170.1 Has BC Hydro attempted to quantify any of the risks noted a lines 8-21?

RESPONSE:

The three risks noted on page 7-38 of Exhibit B-1 were not quantified and BC Hydro is uncertain as to how these risks could be meaningfully quantified. To be responsive BC Hydro offers the following observations:

Risk #1:

The uncertainty during pre-schedule trading of whether or not customers will have incremental load increases. BC Hydro asked customers for notification of load increases greater than 10 MW but there is no penalty in RS 1892 that compels them to do so.

Response:

Incremental industrial load under the proposed freshet rate pilot for the upcoming trial period are not expected to have a material impact on operational or marketing flexibility. BC Hydro will be monitoring the impact of the incremental load increase, and customer load notifications, to gauge impact/benefits on both the system and marketing activities.

Risk #2:

If there are differences between the real time market and the day ahead prescheduled market. Customers are billed using the pre-schedule market price, however it is the real-time markets that BC Hydro would be making incremental transactions to cover higher RS 1892 loads. Differences in prices between the real-time and pre-schedule markets represent a risk to BC Hydro.

Response

Differences between real time and day ahead prescheduled market prices are usually symmetric, thus can be expected to net to close to zero. There will be times that differences will result in incremental costs in marketing, however given the given the anticipated small volumes likely to subscribe to the pilot program (5 aMW to about 30 aMW), the risk is not considered to be material. BC Hydro will be monitoring the marketing impact associated with variations in real time versus day ahead market prices, as part of the pilot program.

Risk #3:

Tie line constraints may limit BC Hydro's ability to import from the U.S. market, which means storage could be the source of energy used to supply incremental freshet load. In this situation, there would be opportunity costs if BC Hydro could have instead used the stored energy during a higher valued period.

Response:

Tie line limitations can occur at any point during the freshet period. Through about the mid-May to end of July period, it is anticipated that tie constraints will not be an issue provided major system spills are not anticipated or occurring. For the first half of May it is more likely that energy would be sourced from system storage. The cost of this would be limited to the differential between the system marginal price (opportunity cost) and the daily pre-scheduled market price, and is expected to be small. BC Hydro will be monitoring the impact of tie constraints, as part of the pilot program.

170.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-38

1.170.1 Has BC Hydro attempted to quantify any of the risks noted a lines 8-21?

1.170.1.1 If yes, what are the potential dollars consequences and the likelihood of them occurring?

RESPONSE:

The three risks discussed in BC Hydro's response to BCOAPO IR 1.170.1 are low consequence due to the limited energy volumes anticipated for the pilot program, and accordingly the likelihood of the events underpinning the three risks has not been examined in detail.

170.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-38

1.170.2 The possibility that customers will shift load from non-freshet months of the year into the freshet months was not identified as a risk, even if low. Why not?

RESPONSE:

The lead-in text to the listed three risks on page 7-38 of Exhibit B-1 clearly states that shifting is discussed as a risk in a separate section, namely section 7.3.4.5 of Exhibit B-1. The lead in language at page 7-38 states that shifting is a risk.

At both Workshops 5 and 10, BC Hydro identified shifting load from one customer plant to another, with no net gain in freshet consumption between both facilities, as a risk to non-participating customers. For example, refer to the Workshop 5 consideration memo, Exhibit B-1, Appendix C-5A page 118 of 292; and to the Workshop 10 consideration memo, Exhibit B-1 Appendix C-5B, pages 87 to 89 of 212. Shifting, including between sites owned by the same customer, is included in the pilot's evaluation criteria, which is described on pages 7-43 and 7-44 of Exhibit B-1.

170.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-38

1.170.3 The possibility of customers shifting load from one plant another was not identified as a risk? Does BC Hydro consider this to be a risk?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.170.2.

170.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-38

1.170.3 The possibility of customers shifting load from one plant another was not identified as a risk? Does BC Hydro consider this to be a risk?

1.170.3.1 If no, why not?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.170.2.

170.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-38

1.170.4 How was the $3/MWh value for the proxy wheeling fee established?

RESPONSE:

The $3/MWh value was established using professional judgement taking into consideration the cost and risk rationale discussed on pages 7-37 and 7-38 of Exhibit B-1. Please also refer to BC Hydro's response to BCUC IR 1.108.1, which discusses why the proxy wheeling fee is lower than the originally proposed $6/MWh.

171.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-42

1.171.1 Please clarify what is meant by "Energy is provided on an 'as available' basis at Mid-C market prices".

RESPONSE:

BC Hydro understands the reference to be to RS 1853 which is the rate schedule discussed on page 7-44 of Exhibit B-1. This means BC Hydro will supply energy to IPPs on a non-firm basis at Mid C market prices.

171.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-42

1.171.2 The text at lines 7-8 suggests that BC Hydro views shifting RS 1823 load in non-freshet months to increase RS 1892 load during the freshet months is a valid use of the freshet rate. Please confirm whether or not this is the case.

RESPONSE:

Confirmed.

171.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-42

1.171.2 The text at lines 7-8 suggests that BC Hydro views shifting RS 1823 load in non-freshet months to increase RS 1892 load during the freshet months is a valid use of the freshet rate. Please confirm whether or not this is the case.

1.171.2.1 If yes, please fully explain why and demonstrate that such shifting will be of benefit to BC Hydro and non-participating customers.

RESPONSE:

On page 7-42 of Exhibit B-1 BC Hydro acknowledged there are risks from shifting, but considers these to be low. BC Hydro also listed two potential benefits to non-participating customers from permitting shifting. The risks and benefits from shifting cannot be quantified at this time because BC Hydro does not know:

- **The volumes of freshet energy use;**
- **The extent to which customers will shift (frequency, volume, what enabled the shift);**
- **When customers will reduce load to shift (winter reductions have more value to BC Hydro);**
- **Whether or not the shift will result in a reduction of RS 1823 Tier 1 revenue or Tier 2 revenue. Although BC Hydro forecasts customer load for 2016 and 2017, it does not forecast potential CBL adjustments which would impact the proportion of load billed at Tier 1 or Tier 2; and**
- **Market prices in 2016 and 2017.**

BC Hydro committed (page 7-43 of Exhibit B-1) to explore shifting as part of its evaluation of the pilot.

172.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-44

1.172.1 Can BC Hydro terminate the supply of RS 1853 if it does not have sufficient generation or transmission capacity or is the special condition under the tariff limited to generation capacity?

RESPONSE:

BC Hydro can terminate the supply of RS 1853 if it does not have sufficient generation or transmission capacity.

172.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-44

1.172.2 The RS 1853 tariff provisions state that: "Prior to taking Electricity under this Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of energy under this Schedule" (emphasis added).

RESPONSE:

There is no question in the above-referenced IR.

172.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-44

1.172.2 The RS 1853 tariff provisions state that: "Prior to taking Electricity under this Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of energy under this Schedule" (emphasis added).

1.172.2.1 Under what circumstances would prior BC Hydro approval not be required?

RESPONSE:

Since the IPP customer is connected to BC Hydro's system, the customer will be required to notify BC Hydro of any maintenance or black-start events according to the customer's local operating order.

172.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 7-44

1.172.2 The RS 1853 tariff provisions state that: "Prior to taking Electricity under this Schedule, the Customer may be required to obtain approval from BC Hydro. BC Hydro will advise the Customer of the need to obtain approval prior to the taking of energy under this Schedule" (emphasis added).

1.172.2.2 If prior approval is not required, is the customer required to advise BC Hydro (after the fact) that it is taking service under the rate and, if so, how soon after starting to take service must notice be given?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.172.2.1.

173.0 CHAPTER 7 TRANSMISSION SERVICE RATE DESIGN

Reference: Exhibit B-1, page 45

1.173.1 Can BC Hydro terminate the supply of RS 1880 if it does not have sufficient generation or transmission capacity or is the special condition under the tariff limited to generation capacity?

RESPONSE:

BC Hydro can terminate the supply of RS 1880 if it does not have sufficient generation or transmission capacity.

174.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-6 to 8-7 and Appendix G1-B, pages 1 to 6

1.174.1 For each of the Minimum Connection charges please provide a schedule that contrasts the following with the values used in the 2007 RDA for setting the comparable charge: a) Labour, including hours required and hourly rate, b) Material Costs and Material Handling Charges, and c) Vehicle Costs.

RESPONSE:

	Labour ($)		Travel (Hours)		Site (Hours)		Vehicle ($)		Material ($)	
	2007	2015	2007	2015	2007	2015	2007	2015	2007	2015
100A OH	195.24	479.53	0.77	0.77	0.9	0.9	20.0	80.38	70.92	69.40
200A OH	195.24	479.53	0.77	0.77	0.9	0.9	20.0	80.38	94.73	100.19
100A UG	208.26	508.25	0.77	0.77	1	1	22.4	85.20	158.90	160.45
200A UG	273.34	603.01	0.60	0.60	1.5	1.5	29.4	101.08	294.40	295.83
First Install	55.32	122.04	0.60	0.60	0.25	0.25	10.2	20.46	0.00	0.00
Subsequent Meter	22.78	35.89	0.00	0.00	0.25	0.25	0.00	0.00	0.00	0.00

174.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-6 to 8-7 and Appendix G1-B, pages 1 to 6

1.174.2 With respect to the First Subsequent Meter charge, under what circumstances would this meter be required and who would pay for the cost of the actual meter?

RESPONSE:

This charge is used when BC Hydro would be installing multiple meters at the same location on the same day (i.e., condo meter rooms or for multiple townhouses in the same complex). This charge is for the first meter which includes the PLT labour and travel time.

The actual cost of the meter is paid for by BC Hydro.

174.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-6 to 8-7 and Appendix G1-B, pages 1 to 6

1.174.3 With respect to the Additional Meter Installations charge, under what circumstances would additional meters be required and who would pay for the cost of the actual meter?

RESPONSE:

This charge is used when BC Hydro would be installing multiple meters at the same location on the same day (i.e., condo meter rooms or for multiple townhouses in the same complex). This charge is used for all subsequent meters (not including the first subsequent meter already charged) for the same location installed on the same day. This charge includes the PLT labour but no additional travel time.

The actual cost of the meter is paid for by BC Hydro.

174.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-6 to 8-7 and Appendix G1-B, pages 1 to 6

1.174.4 Please provide the supporting details (i.e., labour and vehicle time and costs) to support the manual reconnection performed on overtime charge of $280 per meter.

RESPONSE:

Please refer to the public version of Attachment 1 to BC Hydro's response to BCUC IR 1.124.1.

174.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-6 to 8-7 and Appendix G1-B, pages 1 to 6

1.174.4 Please provide the supporting details (i.e., labour and vehicle time and costs) to support the manual reconnection performed on overtime charge of $280 per meter.

1.174.4.1 If there is more than one meter at the site requiring reconnection, why would each one be subject to the same $280 charge?

RESPONSE:

The proposed Overtime Reconnection charge of $280 is only applicable to the first meter at the site. If the customer has multiple meters at the same location (e.g., a second meter for E-Plus heating load) then he or she would be assessed the Meter Connection (second meter) charge of $46 (proposed) for any additional meter.

The secondary meter charge is for the incremental labour associated with manually reconnecting another meter.

175.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-9 to 8-11

1.175.1 Under what circumstances is a manual reconnection deemed to have been performed on overtime?

RESPONSE:

BC Hydro cannot guarantee same-day reconnection and can only attempt to do so on a 'best efforts' basis. Same-day reconnection may not be possible for reasons such as failure of a remote reconnection, or crew availability or proximity to the customer's location.

In these situations, the customer may request that the reconnection be done outside of regular hours. The customer is informed of the higher cost. If the customer wishes to proceed, the agent will attempt to dispatch a crew to reconnect the service.

The customer is not billed the overtime charge unless the reconnection is completed (e.g., if a crew is not available).

Regular work hours are generally 8 a.m. to 4 p.m., Monday to Friday. However, if customers request a manual reconnection after 3 p.m., they will be informed that the overtime charge may apply. In some locations work hours are extended (e.g., trouble crews based in the Lower Mainland). In these locations, the overtime charge is not applied if the reconnection is performed during regular shift hours, even if after 4 p.m.

Operationally, there are instances when BC Hydro reconnects a service outside of normal working hours without the customer's knowledge (e.g., a crew had already been dispatched but was delayed in transit). The customer is not assessed the higher charge in these cases.

175.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-9 to 8-11

1.175.2 If a customer requests a reconnection outside of normal working hours is the customer advised, in advance, whether the reconnection will be subject to a "manual reconnection performed on overtime" charge or not before the work is performed?

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.175.1.

175.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-9 to 8-11

1.175.3 Under what circumstances is the customer deemed to have "refused access" (per page 8-11). For example, if the customer is not at home and BC Hydro is unable to access the meter, is the customer deemed to have refused access?

RESPONSE:

In this context "refused access" means the customer has taken repeated and intentional steps to prevent BC Hydro from being able to access the meter. This can include installing physical barriers, making threats, repeatedly being unavailable for pre-scheduled meetings, or ignoring BC Hydro's attempts at contact for an extended period. In addition, the customer would be warned prior to having the "refused access" charge applied. Merely being not at home would not result in a customer being deemed to have refused access.

176.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, page 8-7 and Appendix G1-B, page 10

1.176.1 Please describe the circumstances under which a "Service Connection Call-Back Charge" would be levied.

RESPONSE:

Call Back charges apply to situations where BC Hydro has been scheduled by the customer to install or change the customer's service connection and the facilities provided by the customer for this purpose are found to be deficient/inaccessible. Examples can include: service box not exposed, duct blocked (on customer side), connection point not correct (mast), meter base blocked in by siding or not ready, no access to site, house not vacant when crew arrived on a demo order, customer electrical work not completed when crew arrives on site.

176.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, page 8-7 and Appendix G1-B, page 10

1.176.2 Why is the number of PLTs required for this work 1.33 as opposed to 1.0?

RESPONSE:

This number is the average of the number of PLTs required for all potential connection types (i.e., some underground work requires two PLTs while some work only requires one).

176.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, page 8-7 and Appendix G1-B, page 10

1.176.3 Please explain why there is variation in travel time for the various charges that are costed out in Appendix G1-B, ranging from 0.6 hours to 1.0 hours.

RESPONSE:

The referred to range was carried over from 1997 and the 2007 RDA. For purposes of the 2015 RDA, BC Hydro did not review the travel time component of the charges. Only the material, site time, and labour costs were reviewed for current values.

177.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.177.1 Please confirm that the purpose of BC Hydro's late payment charge is to incentivize customers to pay their bills on time.

RESPONSE:

As noted on page 8-13 of Exhibit B-1, BC Hydro views the Late Payment Charge as a means to recover collection and borrowing costs incurred because of delayed payments. Providing an inducement for timely payments is also important but is a secondary factor.

177.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.177.1 Please confirm that the purpose of BC Hydro's late payment charge is to incentivize customers to pay their bills on time.

1.177.1.1 If not confirmed, please describe the purpose of the late payment charge.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.177.1.

178.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.178.1 Assume for purposes of this Information Request that a residential bill is rendered on Day 1. Assume further the bill remains unpaid. Provide the timeline of each collection step until the bill is final-billed for nonpayment. Identify the Day on which each step of the collection process can be expected to occur. If this timeline varies depending on the account holder's credit history, please provide each possible timeline. If this question is fully answered by at Appendix C-3B, Attachment 1 (p. 2176 of the PDF file), please advise.

RESPONSE:

Exhibit B-1, Appendix C-3B, Attachment 1 contains a summarized version of the Dunning (collection) process. Please refer to Attachment 1 to this response for a complete summary of the Dunning process for active Residential accounts.

The Dunning process is based on creditworthiness. Demerit points are added whenever dunning actions take place on one of a customer's accounts. The following are the number of points assigned for each action:

- **Increase dunning level (per the dunning matrix) – Minimum 5 points**
- **Reminder/Important Reminder – 5 points**
- **Final Notice of Disconnect – 10 points**
- **Send to Operator Review – 15 points**
- **Write Off/Bankruptcy - 99 points**
- **Return Item (NSF) - 25 points**
- **Return Item (Non NSF) - 10 points**
- **Disconnect (Non-Pay) - 60 points.**

To calculate creditworthiness, the points are weighted based on how recently each action took place. The weighting is as follows:

- **Less than three months old – 4x**
- **Three months to six months – 3x**
- **Six months to nine months – 2x**

- **Nine months to 12 months – 1x.**

Creditworthiness points are held for a maximum of 12 months. This means that if a customer with a poor payment history maintains on time payments for one year from the time of the last dunning action, he or she will have no creditworthiness points remaining.

Dunning Process – Active Residential Accounts

"Days" = Days late after standard 21 day payment term)

Dunning Procedure (1)	Credit Wrthnss	Min / Max $Amount	DL1 ~ 7 Days	DL2 ~ 21 Days	DL3 ~ 35 Day	DL4 ~ 49 Days	DL5 ~ 63 Days	DL6~73 Days	DL7 ~83 Days
AA Active Account (Good)	0 – 150	> 30.00 < 10,000.00	1. No activity	1. Reminder	1. Important Notice 2. If not on Security Deposit, Print Warning	1. Final Notice of Disconnection	**>70. 00** 1. Deactivate EPP 2. Operator Review	**>70.00** 1. Operator Review	**>70.00** 1. Operator Review
AA Active Account (Medium)	151 – 325	> 30.00 < 10,000.00	1. No activity	1. Important Notice 2. If not on Security Deposit, Print Warning	1. Final Notice of Disconnection	**> 70. 00** 1. Operator Review	**> 70. 00** 1. Deactivate EPP 2. Operator Review	**>70.00** 1. Operator Review	**>70.00** 1. Operator Review
AA Active Account (Bad)	= or >326	> 30.00 < 10,000.00	1. Final Notice of Disconnection 2. Security Deposit Request (if not secured)	**> 70. 00** 1. Operator Review	**> 70. 00** 1. Operator Review	**>70. 00** 1. Operator Review	**>70. 00** 1. Deactivate EPP 2. Operator Review	**>70.00** 1. Operator Review	**>70.00** 1. Operator Review
AN Active New	All	> 30.00 < 10,000.00	1. Final Notice of Disconnection 2. Security Deposit Request (if not secured)	**> 70. 00** 1. Operator Review	**> 70. 00** 1. Operator Review	**> 70. 00** 1. Operator Review	**>70. 00** 1. Deactivate EPP 2. Operator Review	**>70.00** 1. Operator Review	**>70.00** 1. Operator Review
All Accounts	All	> 10,000.00	1. Operator Review	1. Operator Review	1. Op. Review	1. Op. Review	1. Op. Review	1. Op. Review	1. Op. Review
SD Security Deposit	All	> 70.00	1. Final Notice of Disconnection	1. Operator Review					
IP Installment Plan (IP)	All	>30.00	1. Deactivate IP						
IG GAIN IP	All	>30.00	1. Operator Review	1. Deactivate IP					

179.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.179.1 For the most recent 12-month period available, by month for residential accounts, please provide:

(a) What percentage of bills were paid by the due date of the bill.
(b) What percentage of bills were paid by the time the next month's bill is rendered.
(c) What percentage of those bills were paid by the time the second subsequent bill is rendered.
(d) What percentage of those bills were paid by the time the third subsequent bill is rendered.

RESPONSE:

BC Hydro's standard arrears reports provide consolidated account information and so do not have sufficient details to allow a response to this IR.

This notwithstanding, BC Hydro acknowledges the usefulness of this information and so is attempting to extract and analyze account-level transactional data from the billing system. Given the complexity of this analysis (it requires analysis of over 134 million points of data) it will be provided as part of BC Hydro's responses to Round 2 IRs.

180.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.180.1 Please provide the dollars of residential late fee revenue collected by month for each month January 2012 to present.

RESPONSE:

The following table identifies Late Payment Charge revenue (in $000s) by month since April 2011. Both Residential and General Service revenues are shown, as BC Hydro does not track Late Payment Charge revenue by customer type.

($)	F2012	F2013	F2014	F2015	F2016
Apr	604	734	739	818	728
May	589	646	705	737	421
Jun	589	657	600	991	616
Jul	703	672	584	622	563
Aug	522	504	523	505	554
Sep	382	499	579	599	510
Oct	430	539	484	727	432
Nov	405	292	432	512	
Dec	422	561	652	455	
Jan	638	318	740	556	
Feb	593	674	505	589	
Mar	715	671	857	733	
Total	6,592	6,768	7,399	7,844	3,825

180.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.180.2 Please provide the number of residential accounts paying a late charge by month for each month January 2012 to present.

RESPONSE:

Please refer to Attachment 1 of this IR response for the number of residential accounts that incurred Late Payment Charges.

Number of accounts incurred Late Payment Charge

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2012	146,815	132,654	150,456	143,512	151,144	150,381	150,858	155,617	132,884	158,866	135,117	124,358
2013	149,799	128,155	143,394	156,920	152,503	144,432	158,865	148,137	147,085	154,771	127,948	136,992
2014	153,668	124,704	152,607	142,566	159,678	151,576	161,534	145,168	154,121	148,894	128,812	139,670
2015	148,472	126,944	149,947	139,669	137,128	155,977	157,463	142,469	146,474	150,702		

181.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.181.1 Please provide a single copy of all studies within BC Hydro's custody or control documenting the effectiveness of a late payment charge as an incentive to pay for:

(a) Residential utility customers.
(b) Low-income residential customers.

RESPONSE:

BC Hydro does not have any studies on the effectiveness of the Late Payment Charge as an incentive to pay outstanding balances.

182.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.182.1 Please provide by month for each month January 2012 to present, a distribution of the number of residential accounts in arrears by the size of arrears by the following bands: (1) $0 - $100; (2) $101 - $200; (3) $201 - $300; (4) $301 - $500; (5) $501 - $750; (6) $751 - $1,000; (7) $1,001 - $2,000; and (8) $2,001 and above. If these bands are not available, please provide the numbers of accounts by which bands are available.

RESPONSE:

BC Hydro does not preserve historical account-level arrears data and so cannot provide this information from January 2012 as requested.

Please refer to Attachment 1 to this IR response for a breakdown of active residential account arrears based accounts in arrears on December 2, 2015.

Active Residential Accounts in Arrears on Dec 2, 2015

	Accounts		Amount		Accounts	Amount
AR Buckets	Electrically Heated	Non-Electrically Heated	Electrically Heated	Non-Electrically Heated	Total	Total
A: $0-$100	27,188	42,364	$1,093,030	$1,676,628	69,552	$2,769,658
B: $101-$200	9,362	15,942	$1,327,178	$2,240,705	25,304	$3,567,883
C: $201-$300	3,852	5,557	$934,648	$1,345,699	9,409	$2,280,346
D: $301-$500	2,344	2,842	$878,477	$1,060,232	5,186	$1,938,709
E: $501-$750	715	802	$427,342	$473,818	1,517	$901,160
F: $751-$1,000	233	266	$199,230	$229,517	499	$428,747
G: $1,001-$2,000	264	302	$362,694	$408,870	566	$771,564
H: $2,001+	129	225	$555,137	$948,745	354	$1,503,882
Grand Total	44,087	68,300	$5,777,736	$8,384,212	112,387	$14,161,948

Aging of Active Residential Accounts in Arrears on Dec 2, 2015

	B: 30-60 Days		C: 61-90 Days		D: 91-120 Days		E: 121-150 Days		F: 151-180 Days		G: 181+ Days		Grand Total
AR Buckets	Electrically Heated	Non-Electrically Heated	Electrically Heated	Non-Electrically Heated	Electrically Heated	Non-Electrically Heated	Electrically Heated	Non-Electrically Heated	Electrically Heated	Non-Electrically Heated	Electrically Heated	Non-Electrically Heated	
A: $0-$100	20,764	32,022	4,994	7,950	800	1,406	372	579	99	161	159	246	69,552
B: $101-$200	7,170	12,232	1,095	2,034	642	1,068	229	301	98	122	128	185	25,304
C: $201-$300	2,871	3,984	481	756	276	476	100	153	55	65	69	123	9,409
D: $301-$500	1,542	1,738	328	392	233	366	88	127	63	78	90	141	5,186
E: $501-$750	370	371	110	99	93	117	38	75	37	54	67	86	1,517
F: $751-$1,000	98	97	20	44	28	36	16	21	15	15	56	53	499
G: $1,001-$2,000	107	126	28	37	25	27	9	15	12	18	83	79	566
H: $2,001+	66	115	8	18	12	13	3	10	4	2	36	67	354
Grand Total	32,988	50,685	7,064	11,330	2,109	3,509	855	1,281	383	515	688	980	112,387

183.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.183.1 Please provide the total costs of the Accenture Business Service (ABSBC) credit and call center included in revenue requirement for this rate case.

RESPONSE:

As provided by section 42 of the *ATA* and section 1 of the Commission's Confidential Filings Practice Directive, BC Hydro requests confidential filing with the Commission for those parts of Attachments 1 to 3 which relate to ABSBC and other contractor cost information on the basis that:

- **Such information is financial and commercial information that is confidential and has consistently been treated as confidential by BC Hydro and ABSBC; and**
- **Disclosure of such information could reasonably be expected to result in significant harm or prejudice to ABSBC's competitive or negotiating position.**

Below is a consolidated response that addresses a number of questions requesting BC Hydro to explain and provide support for the costs it has associated with its collection activities. For this purpose, "collections" is assumed to be costs incurred to obtain payment of balances in arrears, costs incurred establishing security for accounts, and bad debt expenses if payment is not received. Costs of investigating electricity theft are excluded.

Costs have been provided for the period F2013 to F2015. This period was selected because F2013 reflects the first year in which collections began using RDR, and so prior years are not reflective of current practices. As requested in BCOAPO IR 1.220.1, all costs identified in this response exclude administrative and overhead expenses.

Collection costs for Residential and General Service customers are incurred in three departments:

1. Customer Service Operations (CSO)

CSO is part of BC Hydro's Transmission, Distribution and Customer Services business unit. CSO has primary accountability for revenue cycle operations and mass market contact channels, and so incurs most of BC Hydro's costs related to collections.

Attachments 1, 2 and 3 provide CSO's plan and actual costs, as well as supporting budget materials. Budget materials have been edited to remove employee names but are otherwise the templates used to upload the plans into the financial system, which reflect financial submissions to the Commission in prior RRAs.

The following provides line item references for CSO's F2015 plan (Attachment 3). Budget materials for all years are identical and so similar details can be identified for prior years.

Tab and Cell	Collections Activity	Source
19452_F15 (I10)	Labour	Refer to BC Hydro's response to Commission IR 1.126.4
19452_F15 (I18)	Dunning Notifications	Paper, Printing and Postage for bills and notifications are identified in TPC_F15 tab (cell S33). See below for explanation of allocation.
	Collection Agency Fees	See cell S18. Detail from TPC_F15 tab (cell S55).
	Credit Checks	Detail from TPC_F15 tab (cell S56).
19670_F15 (I42)	ABS - Collections	100% of cell K42, which equate to the collections costs specified in RAMSA
	ABS - Call Centre	Allocation of costs in ABS_F15 tab (cell AU17) based on call types and handling times. See below.
19670_F15 (I46)	Bad Debt Expense	Residential and General Service Bad Debt Expense.

As noted in the table, some of these costs are directly identified in the plan while others require allocation of costs within a larger cost category. These allocations are described as follows:

<u>Dunning Notifications</u>

The Contract Services plan and actuals include costs incurred for paper, envelopes, printing and postage, for both customer bills and non-bill correspondence (which includes Dunning notifications). The plan is based on the total volume of bills and correspondence sent and does not specifically identify the cost of Dunning notifications.

Actual volumes of each letter type are known, as are actual printing and postage costs. Accordingly, the unit cost in each month multiplied by the total number of letters related to Dunning to determine the overall cost of Dunning Notifications, as shown in Attachment 4 to this IR response, tab B.

<u>ABSBC Costs</u>

ABSBC costs for the call centre and collections are recorded within cost element 635240, which had a total plan cost of $25.4 million. Collections costs are reflected in two areas:

- **Credit and Collections, which is a specific line item under RAMSA, at a cost of $3.11 million in F2015, and**
- **Customer Service (i.e., the call centre), which had a plan cost of $15.64 million in F2015.**

These costs are shown in tab ABS_F15 of Attachment 3 to this IR response.

The estimate of collection charges in F2015 includes 100 per cent of the Credit and Collections charge from ABSBC, as well as a portion of Customer Service calls that are considered as being related to collections. Three call types are associated with collections:

- **100 per cent of calls for Payment Arrangements;**
- **10 per cent of calls for Payment Inquiry, and**
- **10 per cent of calls for Payment Options.**

The costs of these calls were determined based on operational records of volumes and handling times as recorded in the call centre telephony systems. This reflects that different call types require varying degrees of effort. The total handling time of each call type was multiplied by the loaded cost of a customer service representative to determine the collections costs incurred within the call centre. This method is consistent with how agent costs have been calculated in the derivation of Standard Charges.

Call coding was changed in F2015. In prior years, the allocation assumed 30 percent of calls coded as "Invoice/Balance/Payment Inquiry" were related to collections.

ABSBC costs relate primarily to collections on active accounts. Collections for closed accounts are performed by external collection agencies that are paid on commission as indicated in the table above.

<u>Manual Disconnections and Reconnection</u>

A small percentage of disconnections and reconnections are performed manually by Field Metering Analysts (FMAs). FMA costs are included in account 635250 – Meter Reading.

Note, however, that CSO's plan and actuals for meter reading and other field services do not reflect the direct costs of FMAs as a result of accounting methods related to SMI deferral accounts. Accordingly, the costs of performing manual disconnections and reconnections have been calculated separately, as shown in the Field & Grid Operations section below.

2. Treasury

BC Hydro's Treasury department plans for costs of interest paid on security deposits. Plan and actual amounts for F2013 to F2015 are as follows:

Fiscal Year	Plan ($000)	Actuals ($000)
2013	1,600	1,681
2014	1,600	1,819
2015	1,800	1,868

Costs of borrowing that result from delayed collection of revenue are not explicitly included in BC Hydro's budget; however, they are factored into the overall costs of borrowing.

As explained in BC Hydro's response to BCUC IR 1.126.2, the interest cost of delayed revenue is calculated at WACD. This rate was applied to the average aged accounts receivables as shown in Attachment 4 to this IR response, tab C. There is not a specific budgeted item for this cost.

Calculated interest costs from delayed revenue are as follows:

Fiscal Year	Actuals ($000)
2013	2,243
2014	2,326
2015	2,182

Note that for consistency with prior years the F2015 average Aged A/R is taken from a different source than that used for the Late Payment Charge costing discussed in section 8.3.3 of Exhibit B-1. Accordingly the calculated interest charge for F2015 above is higher than the interest identified in Table 8-5 of Exhibit B-1.

Treasury also has some labour costs related to credit and collections activities for residential and commercial operations. As noted in BC Hydro's response to BCUC IR 1.126.4, this effort has been roughly estimated as one-quarter of a FTE, or $0.05 million annually.

3. Field and Grid Operations (F&GO)

A small percentage of manual disconnections and reconnections are performed manually by Powerline Technicians or Meter Technicians from F&GO. Similar to the situation with FMAs, plan and actual budget data is not relevant because of accounting for the SMI deferral during the transition period.

Given the transition to RDR and accounting for SMI deferral accounts as described above, collection costs associated with manual disconnections and reconnections are estimated based on the Minimum Reconnection Charge.

The derivation of the Minimum Reconnection Charge is provided in BC Hydro's response to BCUC IR 1.124.1. Agent costs are already considered within the ABSBC costs described above; after removing these costs to avoid double-counting, an average weighted cost of $24.43 is attributed to the efforts of field crews to disconnect and subsequently reconnect service.

As noted in Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1, nearly all disconnections for non-payment result in the customer being reconnected. As a result, multiplying the volume of disconnections performed by the unit cost above provides a reasonable approximation of the costs incurred performing manual disconnections and reconnections following the transition to RDR. Costs are as follows:

Fiscal Year	Disconnection Volume	Cost ($000)
2013	**4,995**	**122**
2014	**20,940**	**512**
2015	**38,103**	**931**

Summary of Costs

Department	Collections Activity	F2013 ($)		F2014 ($)		F2015 ($)	
		Plan	Actual	Plan	Actual	Plan	Actual
Customer Service Operations	Labour	n/a	200	n/a	200	n/a	200
	Dunning Notifications	n/a	1,151	n/a	1,154	n/a	1,696
	Collection Agency Fees	485	571	485	635	525	715
	Credit Checks	86	107	91	109	91	127
	ABS - Collections	2944	2,944	3,020	3,020	3,105	3,105

Department	Collections Activity	F2013 ($)		F2014 ($)		F2015 ($)	
		Plan	Actual	Plan	Actual	Plan	Actual
	ABS - Call Centre	n/a	589	n/a	456	n/a	628
	Bad Debt Expense	6,800	6,949	7,300	7,209	7,300	8,746
Treasury	Interest Paid on Security Deposits	1,600	1,681	1,600	1,819	1,800	1,868
	Labour	n/a	50	n/a	50	n/a	50
	Interest Cost of Delayed Revenue	n/a	2,243	n/a	2,326	n/a	2,182
Field & Grid Operations	Manual Disconnect and Reconnect	n/a	122	n/a	512	n/a	931
Total			16,608		17,490		20,248

183.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.183.2 Separately provide the total ABSBC costs for each of the past three fiscal years.

RESPONSE:

Actual OMA costs of ABSBC credit and call centre costs were:

F2013 - $29.4 million

F2014 - $28.3 million

F2015 - $26.8 million.

183.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.183.3 For each total cost provided in response to "a", provide the allocation of those total costs to credit and collection.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.183.1.

183.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.183.4 For each allocation provided immediately above, provide both a description of the basis upon which the allocation was made and the data on which the allocation was made.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.183.1.

184.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.184.1 Please provide, in a live Excel spreadsheet, in sufficient detail to allow replication, with all formulas intact, the derivation of the weighted average interest cost cited in BC Hydro's application using a weighted average cost of debt of 4.28%.

RESPONSE:

The requested information is provided in Attachment 1 to this response.

Interest is paid on security deposits using the actual WACD for the prior fiscal year. As a result, the F2015 borrowing cost cited is based on the actual WACD for F2014, which was 4.28 per cent.

185.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.185.1 Please provide by month since January 2012:

(a) The total number of calls received for BC Hydro by ABSBC credit and call center, disaggregated by the reason for the call;
(b) All studies, evaluations, reports or other written documents of any nature that assess or otherwise discuss an allocation of staff time in hours, days, or increments of hours and/or days by the ABSBC credit and call center disaggregated by the reason for the call;
(c) All studies, evaluations, reports or other written documents of any nature that assess or otherwise discuss the degree to which in-bound calls to the ABSBC credit and call center result in first-call resolution of the reason for the call;
(d) All studies, evaluations, reports or other written documents of any nature that assess or otherwise discuss the allocation of ABSBC costs, disaggregated by the reason for the call, between in-bound calls and out-bound calls; and
(e) All studies, evaluations, reports or other written documents of any nature that assess or otherwise discuss the allocation of ABSBC costs disaggregated by calls and personal contacts.

RESPONSE:

ABSBC agents code in-bound calls by type. Please refer to Attachment 1 to this IR response for the data requested in response to (a) and (b). Note that the codes changed in May 2014 as a result of an upgrade to BC Hydro's telephone systems, and so there are two sets of data related to the requested time period.

Please refer to Attachment 1 to BC Hydro's response to BCOAPO IR 1.214.1 for information on first call resolution, as requested in (c).

BC Hydro does not have information related to items (d) and (e).

186.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.186.1 In a typical month, with Day 1 being the day a bill is issued, please provide the percentage of residential accounts making payments by day through Day 30. If reporting of such data is only by a time period other than a day (e.g., weekly), provide by the reporting by that time period.

RESPONSE:

BC Hydro's standard arrears reports provide consolidated account information and so do not have sufficient details to allow a response to this IR.

This notwithstanding, BC Hydro acknowledges the usefulness of this information and so is attempting to extract and analyze account-level transactional data from the SAP billing system. Given the complexity of this analysis (it requires analysis of over 134 million points of data) it will be provided as part of BC Hydro's responses to Round 2 IRs.

187.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3.3
Late payment charge

1.187.1 Please provide a list of all circumstances other than full payment of a bill that stop:

(a) The collection process for BC Hydro residential customers (e.g., entering into a deferred payment plan, filing a medical certificate, the winter shutoff moratorium); and
(b) The imposition of a late payment charge on a residential account in arrears.

RESPONSE:

The collection process (including disconnection) is stopped when:

- **The customer has paid the bill in full;**
- **The amount in arrears is less than $30;**
- **An Installment Plan has been created for the outstanding balance;**
- **The customer has reported a payment (disconnection stopped pending posting of payment);**
- **The customer has deferred a payment; and**
- **Dunning locks have been applied (e.g., while a meter test is being conducted or a Commission complaint is being resolved, to allow for payment due to a bill delivery issue).**

In addition to the above reasons for stopping the collections process, other reasons why the account would not be disconnected include:

- **The outstanding balance is less than $70;**
- **If the customer has a security deposit, the balance in arrears is no more than $10 more than the security deposit held;**
- **The customer has applied (or indicated they will be applying) for MSDSI assistance, during the period of MSDSI's evaluation;**

- **Compassionate issues (e.g., customer in the hospital, recent death in the family) or the disconnection would put the customer at serious personal risk, at the discretion of the credit work leader;**

- **The period falls during the Christmas – New Year disconnection moratorium; or**

- **A disconnection becomes 'stale' because it has not been executed within 21 days and requires another operator review.**

The imposition of a late payment charge on a residential account in arrears is stopped when:

- **The outstanding balance is less than $30;**

- **The outstanding balance has been transferred to an Installment Plan; or**

- **Interest locks have been applied for the same reasons a Dunning lock might be applied.**

188.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.3

1.188.1 Please provide a detailed explanation of the order in which customer payments are applied against various components of an account balance. Indicate, for example, whether late payment charges are paid before usage charges, whether unpaid balances are paid in the order in which they were incurred, etc.

RESPONSE:

A payment is applied against balances in the order in which they were incurred.

189.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.4
Security deposits

1.189.1 For each month starting from January 2012 to present, please provide:

(a) The number of residential accounts for whom cash security deposits were held;
(b) The dollar amounts of cash security deposits held for residential customers;
(c) The number of cash security deposits applied to final bills;
(d) The percentage of final bills paid by security deposits applied to said bills; and
(e) The dollars of cash security deposits applied to final bills.

RESPONSE:

With respect to (a), (b), (c) and (e), please refer to Attachment 1 of this IR response.

Results are provided for security deposits assessed in 2012 and 2013. As security deposits are normally held for 12 months, most security deposits assessed in 2014 and 2015 would not have been returned or applied by the time the data was extracted, and accordingly 2014 and 2015 data has not been provided.

With respect to (d), this information is not available.

190.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-24 to 8-28

1.190.1 With respect to security deposits, given the proposed "up to" wording change (per page 8-21), why would a tariff amendment be necessary if income becomes a criterion (per page 8-24)?

RESPONSE:

As described in Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1, BC Hydro has no evidence to suggest that credit worthiness is linked to income.

Even if security deposits were waived for low income customers, BC Hydro still desires flexibility to enable a standardized security deposit for smaller residential accounts such as apartments, as well as a graduated security deposit when the financial risk does not warrant a security of 2 times/3 times the customer's average monthly bill. These changes have administrative, collections and customer service benefits. In this regard please refer to BC Hydro's response to BCUC IR 135.4.

190.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-24 to 8-28

1.190.1 With respect to security deposits, given the proposed "up to" wording change (per page 8-21), why would a tariff amendment be necessary if income becomes a criterion (per page 8-24)?

1.190.1.1 What types of factors does BC Hydro view as being possible to take into account in applying the "up to" qualification without a tariff amendment?

RESPONSE:

As required under the current section 2.4 of the Electric Tariff, if BC Hydro determines that a customer has not demonstrated acceptable credit then the security deposit must be equal to 2 times/3 times the average monthly bill.

Accordingly, outside of BC Hydro determining that a security deposit is not required or the customer participating in Pay-As-You-Go billing, there are no factors that make it possible to apply the "up to" qualification without a tariff amendment.

190.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-24 to 8-28

1.190.1 With respect to security deposits, given the proposed "up to" wording change (per page 8-21), why would a tariff amendment be necessary if income becomes a criterion (per page 8-24)?

1.190.1.2 Given these factors, how will BC Hydro determine the level of security deposit required in any particular circumstance?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.135.4.

190.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-24 to 8-28

1.190.2 Does BC Hydro return security deposits to customers after they have established a “good payment history” (per page 8-19)?

RESPONSE:

Yes.

190.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-24 to 8-28

1.190.2 Does BC Hydro return security deposits to customers after they have established a "good payment history" (per page 8-19)?

1.190.2.1 If so, how long a period of "good payment" is required?

RESPONSE:

BC Hydro currently returns security deposits after 12 consecutive months without late payment. The security deposit is left as a credit on the customer's account but the customer can request that a refund cheque be issued.

BC Hydro is considering extending this time period for an automatic return, in view of evidence that 12 months is ineffective for rental apartments.

190.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-24 to 8-28

1.190.3 With respect to Billing Errors, what is the standard extended repayment period employed by BC Hydro?

RESPONSE:

As specified in current section 5.8 of the Electric Tariff, when Residential customers were under-billed due to billing errors, BC Hydro back-bills customers for the shorter of the duration of the billing error or six months. If requested by the customer, the repayment term will be equivalent in length to the back-billing period. Longer terms may be offered depending on the magnitude of the adjustment.

Although not billing errors, in situations such as a true-up after an extended period of estimated bills or after resolution of a billing dispute, BC Hydro may offer longer payment terms up to 12 months, again depending on the magnitude of the adjustment.

190.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-24 to 8-28

1.190.4 With respect to the Disconnection Grace Period, what are the specific process changes that BC Hydro is looking to implement?

RESPONSE:

Please refer to Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

190.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-24 to 8-28

1.190.5 With respect to Arrears Payment Arrangements, is the repayment period common for all with similar sizes of outstanding balances or is there currently some flexibility to the repayment period?

RESPONSE:

The repayment period for balances in arrears is generally up to three months; however, work leaders and Customer Relations staff have some flexibility in establishing longer repayment periods. Repayment terms are negotiated with the customer depending on the size of the outstanding balance, the customer's ability to pay, and the perceived likelihood that the customer's account will result in bad debts. As noted in Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1, a key consideration in granting a longer repayment term is whether or not the customer's arrears can be repaid prior to the upcoming winter heating season.

Longer payment terms are also offered because of billing errors or when BC Hydro's operations were a contributing factor towards the customer's arrears (e.g., true-up after consecutively estimated bills).

190.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, pages 8-24 to 8-28

1.190.6 What is BC Hydro's current policy/practice with respect to Winter Disconnects?

RESPONSE:

BC Hydro disconnects for non-payment throughout the year with the exception of a two to three-week moratorium in the Christmas – New Years holiday period. When sub-zero temperatures are expected, winter customers are provided an additional 72 hour notice to allow the customer additional time to pay their bill or prepare their premises for cold weather.

Current disconnection practice is consistent with the "Sub-Zero Disconnection Procedure" described in the June 2014 Freedom of Information request provided to BCOAPO, which was included in the stakeholder engagement materials (Exhibit B-1, Appendix C-3D, pages 11 to 17 of 67).

191.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.191.1 Disaggregated by heating and non-heating residential customers, please provide by month for each month January 2012 to the present:

(a) The average bill for all residential accounts;
(b) The average arrears of residential accounts in arrears;
(c) The average bill of residential accounts in arrears;
(d) The total dollars of residential arrears
(e) The percentage of residential dollars constituting arrears;
(f) The percentage of billed residential accounts having arrears; and
(g) The average arrears of all residential accounts disconnected for nonpayment in that month.

RESPONSE:

With respect to (a), please refer to Attachment 1 to this IR response.

Account level arrears information is required to disaggregate residential customers by heating types. BC Hydro does not preserve historical account-level arrears data and so cannot provide this information from January 2012 as requested. The information below was analyzed based on a point-in-time data extraction on December 2, 2015.

For this analysis, accounts in arrears were considered to be those with outstanding balances 30 days or more after invoicing. Only those accounts that are occupied residences and have a heating type associated with their account were included.

(b) Average active residential account arrears

Heating Type	Average Arrears ($)
Electric Heated	132
Non-Electric Heated	123

(c) Average bills of active residential accounts in arrears

Heating Type	Average Bills ($)
Electric Heated	177
Non-Electric Heated	139

(d) Total dollars of active residential arrears

Heating Type	Total Arrears ($)
Electric Heated	5,777,736
Non-Electric Heated	8,384,212

(e) The percentage of active residential arrears constituting total arrears

Heating Type	%
Electric Heated	23
Non-Electric Heated	34

(f) Percentages of active residential accounts in arrears on December 2, 2015 of total active residential accounts in December 2015.

Heating Type	%
Electric Heated	3
Non-Electric Heated	4

(g) This information is not available. Account balances constantly change. The arrears of residential accounts at the point of disconnection are not tracked and stored.

192.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.192.1 Please provide the final low income terms and conditions "business case" analysis prepared by the BC Hydro in 2015.

RESPONSE:

Please refer to Attachment 1 to this IR response.

2015 Rate Design Application

Assessment of Potential Low Income Terms & Conditions

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Table of Content

1. Introduction 4
2. Review Parameters 5
   2.1 Definition of Eligible Low Income Customers 5
   2.2 Scope of Potential Low Income Terms and Conditions 6
      Table 1: Potential Low Income Terms and Conditions 7
3 Differences Between Cost-Benefit and Cost-Effectiveness 13
      Table 2: BC Hydro Collection Costs ($000s) 15
4 Review Context 16
   4.1 Customer Segmentation by Income 16
   4.2 Update on Work with Ministry of Social Development and Social Innovation 18
   4.3 BC Hydro Collections Performance 19
      Figure 1: Bad Debt Expense by Fiscal Year 21
      Figure 2: Active Receivables Aged 60+ Days (Residential Electricity Charges) 22
      Figure 3: Disconnection Orders and Disconnections Completed, F2010 to F2014 23
      Figure 4: Residential Active Reviews and Disconnections for Non-Payment 24
5 Assessment of Potential Low Income Terms and Conditions 25
   5.1 Administrative Costs and Determining Eligibility 25
      Table 3: Potential Low Income Terms and Conditions Implementation Costs 28
   5.2 Cost-Benefit Analysis 31
   5.3 Cost-Effectiveness Analysis 31
      Table 4: Credit Action Effectiveness 32
      Figure 5: Residential Revenue Recovered per $1 Collection Cost 33
      Table 5: On-time Payments 34
      Table 6: Payment of Arrears 34
      Table 7: Disconnections for Non-Payment 35
   5.4 Assessment of Each Proposed Low Income Terms and Conditions 36
      5.4.1 Security Deposit Waiver 36
      5.4.2 Flexible Arrears Payment Arrangements 40

Figure 6: Typical Seasonal Variation in Consumption 42
5.4.3 Disconnection Grace Period 44
5.4.4 Winter Disconnections 45
Figure 7: Extreme Minimum Temperature Zones 47
Figure 8: Energy Star Climate Zones 47
Figure 9: Customers by Energy Star Zone 48
Figure 10: Disconnections by Energy Star Zone 48
Table 8: Canadian Electric Utilities Using Load Limiters During Winter Period 49
5.4.5 Late Payment Charge Waiver 52
5.4.6 Minimum Reconnection Charge Waiver 53
5.5 Discussion of Other BCOAPO Suggestions 54
5.5.1 Low Income Customer Services Unit 54
5.5.2 Winter Disconnection Survey 54
5.5.3 Low Income Advisory Group 55
5.5.4 Periodic Reporting 56
5.5.5 Additional Collections Metrics 57
5.5.6 Designation of a Third Party to Receive Collection Notices 58
5.5.7 Medical Emergencies 59
5.5.8 Application of Unclaimed Security Deposits to a Crisis Intervention Fund 60
5.6 Summary 60

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1. Introduction

BC Hydro and British Columbia Old Age Pensioners' Organization *et al* (**BCOAPO**) agreed to exchange information concerning potential low income terms and conditions. Subsection 59(1) of the *Utilities Commission Act* places constraints on public utilities such as BC Hydro – public utilities must not make, demand or receive "an unjust, unreasonable, unduly discriminatory or unduly preferential rate for service by it" in British Columbia (**B.C.**). As noted in section 8.6, page 8-23, lines 2-5 of the 2015 Rate Design Application (**Exhibit B-1**), BC Hydro communicated its view to BCOAPO that if BC Hydro were able to demonstrate that adoption of low income terms and conditions will lower BC Hydro costs such as reductions in bad debt and/or collection costs, low income terms and conditions would not be unduly preferential/unduly preferential or otherwise unlawful.

This document provides BC Hydro's initial review of potential low income terms and conditions for service. The document is organized as follows:

- Section 2 describes the two main parameters of the review: (1) how to define eligible low income customers; and (2) the scope of potential low income terms and conditions. As noted in section 5.1 of Exhibit B-1, BC Hydro's review of potential low income terms and conditions does not include: (i) a low income rate pursuant to which low income customers are charged a lower rate for electricity as compared to the remainder of BC Hydro's residential customers, funded by a charge on other ratepayers or some other mechanism; or (ii) emergency bill assistance grants funded by ratepayers such as the Ontario's Low Income Energy Assistance Program (**LEAP**) pursuant to which eligible low income customers are provided a maximum of $500 per household per calendar year (maximum of $600 per household per calendar year for electrically heated homes);

- Section 3 discusses the two approaches used to assess potential low income terms and conditions: (1) cost-benefit analysis, which requires demonstrating that the dollars saved through low income terms and conditions offset the dollars expended on/revenue foregone resulting from adoption of low income terms and conditions; and (2) cost-effectiveness analysis, which requires demonstrating that adoption of low income terms and conditions is a lower cost response to BC Hydro's bad debt and/or collection cost performance as opposed to other alternatives such as devoting increased effort in collections;

- Section 4 sets out the context for the review, including: (1) residential customer segmentation, and in particular the difficulty in establishing that BC Hydro's collection

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results are worse for low income customers as compared to the rest of residential customer base; (2) recent work BC Hydro has undertaken with the B.C. Ministry of Social Development and Social Innovation (**MSDSI**), the B.C. Government entity that among other things can provide crisis supplements for essential utilities if recipients have exhausted all resources and are unexpectedly unable to maintain utilities for their home when served with a disconnection notice or faced with the inability to re-establish utilities;[1] and (3) review of BC Hydro's collections, bad debt and arrearage performance over the period 2010-2015; and

- Section 5 presents BC Hydro's assessment of whether adoption of low income terms and conditions has the potential to either lower BC Hydro costs or otherwise be a cost-effective response to collections, bad debt and/or arrearage performance.

2. Review Parameters

2.1 Definition of Eligible Low Income Customers

A definition of (and verification process concerning) eligible low income customers would be required for adoption of at least three of the potential low income terms and conditions: (1) mandatory waiver of security deposits; (2) mandatory waiver of the Late Payment Charge; and (3) mandatory waiver of the Minimum Reconnection Charges. The definition of '**Eligible Low Income Customer**' for purposes of this review consists of the two criteria:

> A residential customer (1) who has a pre-tax household income at or below the pre-tax Low Income Cut-off (**LICO**) according to Statistics Canada (2) as qualified by a social service agency or government agency such as MSDSI as meeting (1).

Based on the 2014 Residential End Use Survey (**REUS**), approximately 170,000 customers would be eligible for the potential low income terms and conditions (10 per cent of 1.728 million residential customers).

Refer to section 5.5.1 of Exhibit B-1 for the reasons why BC Hydro used Statistics Canada's LICO as the method of defining low income customers. As noted at Exhibit B-1 page 5-67, lines 14-16, the estimated incidence of low income BC Hydro customer households based on Statistics

[1] BC Hydro understands from BCOAPO that crisis supplements for essential utilities can be difficult to access given the test MSDSI applies to determine eligibility: namely, the applicant must establish that (1) they have an unexpected need or expense, (2) they have no other resources available to meet the expense, and (3) failure to meet the expense will result in imminent danger to their physical health or safety.

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Canada's pre-tax LICO measures is 10 per cent across BC Hydro's service area in regards to the 2013 tax year.

BCOAPO suggests the Demand-Side Measures (**DSM**) Regulation approach of proof of income (LICO) or the account holder receiving the benefits listed in the definition of "low income household" in the DSM Regulation. The DSM Regulation section 1 definition of "low-income household" provides a list of pre-qualified recipients of various government income and housing assistance programs. BC Hydro agrees with BCOAPO's proposed DSM Regulation approach to determine eligibility when possible subject to the list of eligible programs being reviewed and adjusted as necessary to reflect a threshold of LICO rather than 130 per cent of LICO as specified in the DSM Regulation. BCOAPO's position is that the DSM Regulation list of benefits should be expanded to include recipients of social assistance on reserve,[2] as well as customers who are eligible for the Leisure Access Program (Vancouver)[3] and equivalent programs in other municipalities, as these programs are income tested. Processes for determining eligibility are further discussed in section 5.1 below.

BC Hydro's review assumes the use of third-parties (social agency and/or government agency, referred to as the intake agency) to determine and communicate eligibility to applicants. BCOAPO indicated its agreement that eligibility for low income terms and conditions should generally be determined by external parties where BC Hydro does not already have that information through MSDSI direct payments or income data collected for BC Hydro's DSM low income Energy Conservation Assistance Program (**ECAP**) eligibility assessments, and that BC Hydro should accept such external determination as adequate.

2.2 Scope of Potential Low Income Terms and Conditions

The six potential low income terms and conditions are set out in Table 1 below:

- As noted in Exhibit B-1, section 8.6, and Appendix C-3D, pages 23 and 24 of 67, BC Hydro and BCOAPO agreed that the Ontario Energy Board (**OEB**)'s Low Income Customer Rules[4] would serve as a starting point for the review.[5] The OEB Low Income Customer

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[2] For a description of how to qualify for social assistance on reserve, see Legal Services Society, Social Assistance on Reserve in BC, January, 2014: http://aboriginal.legalaid.bc.ca/resources/pdfs/pubs/Social-Assistance-on-Reserve-in-BC-eng.pdf.

[3] http://vancouver.ca/parks-recreation-culture/leisure-access-card.aspx.

[4] http://www.ontarioenergyboard.ca/oeb/Consumers/Consumer%20Protection/Help%20for%20Low-Income%20Energy%20Consumers/Low-Income%20Energy%20Assistance%20Program%20%28LEAP%29.

[5] As noted in Exhibit B-1, Table 1 of Appendix C-3D (page 26 of 67), the OEB Low Income Rules were developed through an OEB-initiated engagement process commencing in July 2008, with the OEB Low Income Rules introduced in 2011 with the LEAP. Review of various Ontario electric utility conditions of service indicate that definitions of 'eligible low income customer' were introduced into such conditions of service in October 2011; see, for example, Hydro One Network Inc.'s Distribution Customers: Conditions of Service, 1 January 2015,

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Rules are found in the OEB's Distribution Code, Retail Settlement Code and Standard Supply Service Code. This resulted in five potential low income terms and conditions (security deposit waivers; flexible arrears payment arrangements; disconnection grace period; billing errors; and equalized billing). After discussion with BCOAPO, it was agreed that BC Hydro had substantially achieved the billing error and equalized billing payment portions of the OEB Low Income Customer Rules for the reasons set out in the 'BC Hydro Comments' and 'BC Hydro Response to BCOAPO Comments' columns found in Appendix C-3D, pages 30-33 of 67.

- BCOAPO requested BC Hydro also assess: (1) winter disconnection moratoriums; (2) Late Payment Charge waiver; and (3) Minimum Reconnection Charge waiver. BC Hydro updated the Canadian portion of its jurisdictional review set out at Exhibit B-1, Appendix C-3D, pages 38 to 51 of 67 to determine how many Canadian electric utilities have adopted any of (1), (2) or (3).

Table 1: Potential Low Income Terms and Conditions

Potential Low Income Term/Condition	Jurisdiction and Description	Existing Electric Tariff Provision/ BC Hydro Practice as of September 2015 RDA Filing
1. Security Deposit Waiver	OEB Low Income Customer Rules: Mandatory waiver if low income customer requests waiver; if paid, low income customer can request the return of the security deposit if there are no arrears on the bill. Nova Scotia Power Inc. (**NSPI**) is the only other Canadian jurisdiction that contains a low income-related security deposit waiver in its customer service tariff. The waiver is only available in limited circumstances. Section 6.6 of NSPI's	The existing Electric Tariff security deposit provisions are found in section 2.4: (1) new residential customers are required to provide security deposit or participate in Pay As You Go if he or she has not established credit satisfactory to BC Hydro; (2) existing residential customers are required to provide security deposit or participate in Pay As You Go if he or she has not

Section 4 (Glossary of Terms), "Eligible Low-Income Customer" (effective 1 October 2011), page 125; http://www.hydroone.com/MyHome/MyAccount/ConditionsofService/Documents/HydroOne_Conditions_of_Service_2015_ENGLISH.pdf.

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Potential Low Income Term/Condition	Jurisdiction and Description	Existing Electric Tariff Provision/ BC Hydro Practice as of September 2015 RDA Filing
	Regulations[6] provides: (i) customers receiving social assistance or other similar types of income security payments are not required to make deposits *unless they have a history of a bad credit relationship with NSPI*; and (ii) notwithstanding having a history of bad debt, *if such a customer is unable to pay the deposit*, *NSPI will waive the requirement for a deposit, but a deposit is required if, following the waiver, the customer subsequently defaults in payment or is seeking reconnection following disconnection for non-payment and had a security deposit previously waived with respect to the account that was disconnected*.	maintained credit satisfactory to BC Hydro. As part of the 2015 RDA (section 8.4 of Exhibit B-1) BC Hydro is proposing amendments to section 2.4 of the Electric Tariff to provide BC Hydro with flexibility in the amount assessed, and to enable changes in business practices which will benefit low income customers. This is discussed in Exhibit B-5, BC Hydro's response to BCUC Information Request (**IR**) 1.135.4. Refer to section 5.4.1 below for BC Hydro's assessment of, and proposal concerning, a mandatory security deposit waiver for Eligible Low Income Customers.
2. Flexible Arrears Payment Arrangements	OEB Low Income Customer Rules: Low income customers are allowed more time to pay outstanding balances (8-16 months depending on the amount owed) as compared to BC Hydro's installment plans, which typically provide up to three months and is available to all residential customers. Utilities can cancel the arrears agreement if an eligible low income	Currently, BC Hydro's installment plans are typically up to three months and are available to all residential customers. If a customer defaults on the installment plan the plan cancels and the full balance becomes due immediately. The plan may be re-established if the customer

[6] http://www.nspower.ca/site/media/Parent/Regulations%20-%20January%201%202015%20-%20effective%20June%2029%20Regs%201.1%20and%205.5.pdf.

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Potential Low Income Term/Condition	Jurisdiction and Description	Existing Electric Tariff Provision/ BC Hydro Practice as of September 2015 RDA Filing
	customer defaults more than twice on making an arrears payment, a current bill payment, a security deposit due or an under-billing adjustment. The defaults must occur over at least a 2 month period. In addition, if service is disconnected the low income customer will not have to pay the disconnection/reconnection charge, and non-payment fees and load control device charges are also waived. BC Hydro understands from BCOAPO that Hydro Quebec offers more flexible payment arrangements for low income customers.[7]	does not have a history of failed installment plans. Refer to section 5.4.2 for BC Hydro's assessment of, and proposal concerning, adoption of the OEB's longer installment plan terms and related cancellation conditions.
3. Disconnection Grace Period	OEB Low Income Customer Rules: There is a mandatory suspension of disconnection process for 21 days if an Ontario social agency partner advises that the low income customer may be eligible for emergency assistance.	Currently there is no formal disconnection grace period. Refer to section 5.4.3 for BC Hydro's assessment of, and proposal concerning, adoption of the OEB's 21 day disconnection grace period.
4. Winter Disconnection Moratorium	*Note: No Canadian jurisdiction has implemented winter disconnection policies/moratoriums solely for low income customers; rather, winter disconnection moratoriums apply to all residential customers*. NSPI – Section 6.2(A) of NSPI's Regulations provides that NSPSI will not	BC Hydro's existing sub-zero policy is to provide customers with a 72-hour warning to protect property from possible weather impacts with a disconnection. During the winter holiday season, BC Hydro suspends disconnections for ~2 weeks

[7] Hydro Quebec 2013 Sustainability Report, page 45; http://www.hydroquebec.com/publications/en/docs/sustainability-report/rdd_2013_en.pdf.

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Potential Low Income Term/Condition	Jurisdiction and Description	Existing Electric Tariff Provision/ BC Hydro Practice as of September 2015 RDA Filing
	disconnect electrical service to a residential customer when the weather temperature is 0 degrees Celsius or below or forecast to be 0 degrees Celsius or below anytime in the week following the planned disconnection; Hydro One (Ontario): BC Hydro understands that Hydro One has a policy of not disconnecting residential customers during the winter;[8] Hydro Quebec: Pursuant to section 12.4 of Hydro Quebec's Conditions of Electricity Service, Hydro Quebec will not interrupt service or delivery of electricity between 1 December and 31 March inclusive;[9] Manitoba Hydro: Subsection 104.1(2) of the Manitoba *Public Utilities Board Act*[10] provides that no utility will disconnect residential premises between 1 October and 14 May where the disconnection will affect the supply of heat to the occupied residential premises; Alberta electric utilities: Subsection 2(2) of the Distribution Tariff Regulation[11] states that electric services cannot be fully disconnected between 15 October	prior to the new year but that is connected to staffing, not weather (need staff to be able to reconnect customers following disconnection). Refer to section 5.4.4 for BC Hydro's assessment of, and proposal concerning, adoption of a winter disconnection policy.

8 http://www.thestar.com/news/canada/2015/03/11/hydro-one-blasted-for-threatening-to-cut-off-customers-power-in-winter.html.
9 http://www.hydroquebec.com/publications/en/docs/condition-electricity-service/conditions_service.pdf.
10 C.C.S.M. c. P280; copy available at https://web2.gov.mb.ca/laws/statutes/ccsm/p280e.php.
11 Alberta Regulation 162/2003; http://www.qp.alberta.ca/documents/Regs/2003_162.pdf.

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Potential Low Income Term/Condition	Jurisdiction and Description	Existing Electric Tariff Provision/ BC Hydro Practice as of September 2015 RDA Filing
	and 15 April or any other time when the temperature is forecast to be below 0 degree Celsius in the 24-hour period immediately following the proposed disconnection. However, a load limiter can be installed on a meter to limit the amount of electricity that can be used during this period. It appears to BC Hydro that most U.S. states have winter disconnection policies.[12] The typical trigger is temperatures falling to 32 degrees F or below (and in some cases, temperatures of 98 degrees F and above) or dates between 1 November and 31 March, or both. BC Hydro canvassed the policies of U.S. Pacific Northwest states: Idaho (winter disconnection policy: 1 December - 28 February); Montana (1 November - 1 April); Oregon (no, except with medical certificate); and Washington states (15 November - 15 March).	
5. Late Payment Charge Waiver	The OEB Low Income Customer Rules concerning flexible arrears payment arrangements set out above provide that a utility need to not waive outstanding late payment charges when an eligible customers enters into a low income arrears arrangement; however, such an	Currently, the Late Payment Charge is waived for the period of time a residential customer is on an installment plan; as noted above under #2 (Flexible Arrears Payment Arrangements), BC Hydro's

[12] http://www.liheapch.acf.hhs.gov/Disconnect/disconnect.htm.

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Potential Low Income Term/Condition	Jurisdiction and Description	Existing Electric Tariff Provision/ BC Hydro Practice as of September 2015 RDA Filing
	eligible low income customer cannot be charged additional late payment charges on the amount that is covered by the agreement after he or she has entered into the low income arrears agreement.[13] Aside from the OEB Low Income Customer Rules, BC Hydro is not aware of any Canadian jurisdiction that has adopted mandatory waivers of Late Payment Charges for low income customers.	current installment plans are typically up to three months as compared to the OEB Low Income Customer Rules 8-16 months. Refer to section 5.4.5 for BC Hydro's assessment of, and proposal concerning, a mandatory Late Payment Charge waiver for Eligible Low Income Customers.
6. Minimum Reconnection Charges Waiver	The OEB Low Income Customer Rules concerning flexible arrears payment arrangements set out above provide that a utility is to waive charges related to collection, disconnection, non-payment and/or load control devices when an eligible low income customer enters into a low income arrears agreement for the first time or after he or she has successfully completed a previous such agreement.[14]	Refer to section 5.4.6 for BC Hydro's assessment of, and proposal concerning, a mandatory Minimum Reconnection Charges waiver for Eligible Low Income Customers.

BCOAPO has also suggested that BC Hydro consider several other low income customer service practices that would not necessarily require an amendment to the Electric Tariff:

- A Customer Service initiative for low income customers, specifically a low income customer services unit consisting of staff specifically trained on low income problems. BCOAPO recommended Tacoma Public Utilities in Washington State in this regard. Refer to section 5.5.1 below;

[13] OEB, Ontario Electricity Support Program and Low Income Energy Assistance Program Manual (October 2015), pages 29-30; http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/OESP_LEAP_Program_Manual.pdf.

[14] *Ibid*.

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- Creation of a winter disconnection survey to assess on an annual basis the number of Residential customers who have been disconnected for nonpayment who will enter a heating season without service reconnected. Refer to section 5.5.2;

- Creation of a standing BC Hydro Low Income Advisory Group, which could include (among others) representatives from BC Public Interest Advocacy Center (**BCPIAC**), MSDSI and several client organizations of BCPIAC. Refer to section 5.5.3 below;

- Periodic reporting of specified credit and collection-related data based on data recommended in the United States by the National Association of State Utility Consumer Advocates (**NASUCA**). Refer to section 5.5.4;

- Implementation of additional metrics related to collections performance to provide additional insight into the cost-effectiveness of collections related to low income customers. Refer to section 5.5.5;

- Adoption of an internal business practice of allowing customers to designate a third party to receive collections notices at the same time the customer receives such notices. Refer to section 5.5.6;

- Create a business practice allowing for a delay in the disconnection of service when a customer can certify that the customer, or a permanent resident of the customer's household, has a medical emergency that would be caused by or exacerbated by the disconnection of service. Refer to section 5.5.7;

- Enable unclaimed security deposits to be applied to a crisis intervention fund. Refer to section 5.5.8 below.

BC Hydro and BCOAPO jointly acknowledge that certain rate design proposals that BCOAPO might advocate for, such as a low income rate and an emergency bill assistance program, are outside the scope of this discussion of terms and conditions, and the silence of the parties on these matters does not connote either opposition or support of such proposals.

3 Differences Between Cost-Benefit and Cost-Effectiveness

This review uses two tests:

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- Cost-benefit analysis: Operational cost savings offset revenue losses and administration and other costs associated with implementing the potential low income terms and conditions, including for the process for identifying who is an Eligible Low Income Customer. A cost-benefit analysis is generally used when costs and benefits can be quantified and dollarized;

- Cost-effectiveness analysis: Used to determine which of a set of alternative activities achieves the greatest outcome for the costs expended, e.g., are low income terms and conditions more cost-effective than increased collection action? The purpose of cost-effectiveness analysis is to assess whether an intervention provides value for money.

BCOAPO advised that it disagrees with the use of cost-benefit analysis as a legitimate means to assess low income terms and conditions for four reasons:

- First, a cost-benefit analysis does not specify the public policy decision that has been made that utility service should be preserved where feasible;

- Second, a cost-benefit analysis would need to identify the entire range of benefits over time, a task that would be difficult, if not impossible, to do. For example, the reduced financing costs arising from increased stability in revenue would be difficult to determine;

- Third, a cost-benefit analysis in this instance would assume that all financial and economic benefits can be identified, dollarized and measured. BCOAPO asserts that this assumption would be wrong;

- Fourth, preparing a cost-benefit analysis would require the utility to identify the incremental costs of low income terms and conditions. BCOAPO asserts that BC Hydro would need to determine, over time, what incremental amount of billed revenue would not be collected because of the proposed low income terms and conditions.

As shown in Table 2, BC Hydro incurs costs of approximately $20 million annually because of late and non-payment from customers. Half of these costs are recovered through standard charges applied to customers in arrears and half are recovered through general rates. Details of these costs are further described in Exhibit B-5, BC Hydro's response to BCOAPO IR 183.1.

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Table 2: BC Hydro Collection Costs ($000s)

Cost Driver	F2013	F2014	F2015	Notes
Credit and Call Centre	$3,533	$3,476	$3,733	See BC Hydro's response to BCOAPO IR 1.183.1.
Late Payment Communications	1,151	1,154	1,696	Costs of printing and postage as explained in BC Hydro's response to BCUC IR 1.126.3.
BC Hydro Operations and Maintenance	250	250	250	High-level estimate as explained in BC Hydro's response to BCUC IR 1.126.4.
Credit Checks for New Customers	107	109	127	
Interest on Borrowings for Delayed Revenues	2,243	2,326	2,182	Calculated at weighted average cost of debt (**WACD**). Please refer to BC Hydro's response to BCOAPO IR 1.183.1.
Interest Paid on Security Deposits	1,681	1,819	1,868	
Disconnection	47	198	361	Calculated based on weighted average costs of $9.48 per disconnection and $14.95 per reconnection. Please refer to BC Hydro's response to BCUC IR 1.124.1.
Reconnections	75	313	570	
Bad Debt Expense	6,949	7,209	8,746	Please refer to BC Hydro's response to BCUC IR 1.135.2.
Collection Agency Commissions	571	635	713	
Total	**$16,608**	**$17,490**	**$20,248**	
Method of Cost Recovery				
Standard Charges: • Minimum Reconnection Charge • Late Payment Charge	8,731	$9,287	$10,410	
General rate increases (Revenue Requirement Applications (**RRAs**)	7,877	8,203	9,838	

The above costs are intended to provide context to the types and magnitudes of expenditures that BC Hydro incurs when customers do not pay their bills on time, as well as in implementing processes to mitigate risks of writing-off uncollectible revenue.

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4 Review Context

4.1 Customer Segmentation by Income

BC Hydro has residential customer segmentation information concerning location, primary heating type, size of average bill and dwelling type but does not collect in its billing system the income data from its customers except through the REUS as described in section 5.5.1.1 of Exhibit B-1. Accordingly, BC Hydro has limitations on its ability to correlate collections activities to low income.

BC Hydro was able to obtain some insight into the composition and payment histories of low income customers through both the 2012 REUS and the 2014 REUS, which include questions related to income, and a February 2014 assessment of customers that participated in BC Hydro's low income DSM programs (Energy Savings Kits (**ESKs**) and ECAP; refer to section 5.6.2 of Exhibit B-1 for a description of each; a copy of the February 2014 assessment is found at Attachment 1 to BC Hydro's response to BCOAPO IR 1.208.1) or lived in non-profit housing. Key findings of these reviews were:

- 10 per cent of residential customers would be classified as low income based on pre-tax LICO household income;
- Average annual consumption of low income customers is lower than that of other customers for all dwelling types, although as indicated at page 5-15 and Figure 5-12 of Exhibit B-1, low income customer annual median consumption is only slightly lower overall than for the overall residential customer population, likely due to the higher share of low income customer apartment dwellers compared to the overall residential customer population;
- The "Senior" sample group (aged 65 and above) identified as low income has a similar BC Hydro credit worthiness[15] to the overall "Senior" residential population;
- The "Junior" sample groups (under age 65) identified as low income has a slightly lower credit worthiness than the overall "Junior" residential population:

[15] 'Credit worthiness' is determined based on payment behaviour in the preceding 12 months. Customers are assigned a credit worthiness rating of "good", "medium" or "bad" depending on factors such as the timeliness of payments, returned payments or disconnection of service.

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- 4 per cent had "bad" credit worthiness as compared to 3 per cent for the general "Junior" population;
- 9 per cent had "medium" credit worthiness as compared to 7 per cent for the general "Junior" population;
- 87 per cent had "good" credit worthiness as compared to 90 per cent for the general "Junior" population.

In 2015, BC Hydro also analyzed bad debts for neighbourhoods with incomes identified as being below LICO using postal code income data from Statistics Canada. The key findings were:

- One per cent of BC Hydro residential accounts are located in neighborhoods with household incomes below LICO;[16]
- Only 2.7 per cent of accounts in bad debt were from neighborhoods with incomes below LICO; and
- Only six per cent of accounts receiving MSDSI Direct payments are located in neighborhoods with household income below LICO.

The data does not indicate that income is a factor in a customer's payment history. BC Hydro also concluded that postal code income data is not a good proxy for household income for the purpose of account segmentation, as the finding that only one per cent of accounts are in low income neighbourhoods is not consistent with 2014 REUS findings of 10 per cent of residential customers being low income. BCOAPO conveyed their agreement that neighborhood income, as used by BC Hydro, is not a good proxy for household income for purposes of account segmentation.

BCOAPO believes that segmentation on factors other than income might benefit BC Hydro's understanding of how low income terms and conditions might benefit BC Hydro. BCOAPO provided examples of such segmentation analyses from gas and electric utilities (Wisconsin Public Service).

[16] Assumed 3 occupants per household.

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4.2 Update on Work with Ministry of Social Development and Social Innovation

It is estimated that MSDSI[17] provides income assistance to about 130,000 of BC Hydro's customers; this is approximately two-thirds of the customers that could be eligible for low income terms and conditions. MSDSI's clients are categorized as:

- Direct – MSDSI pays BC Hydro directly for the customer's electricity bills and deducts this amount from his or her income assistance;

- Indirect – The customer pays his or her own electricity bill and MSDSI does not have any involvement with BC Hydro unless the customer applies for a crisis supplement to rectify an account that is in arrears and faces disconnection.

Direct Payments - MSDSI makes Direct payments to BC Hydro for approximately 6,000 of its clients while the remaining clients pay their own electricity bills. In October 2015, BC Hydro and MSDSI created an Information Sharing Agreement to enable sharing of customer data for these customers for the purpose of allowing MSDSI to make payments automatically using Electronic Funds Transfer. This will speed up payments, reduce error rates, tighten information handling security and reduce administrative costs.

Disconnection Grace Period - BC Hydro and MSDSI have recently been working together to improve the experience of low income customers while also reducing operating costs for both organizations. BC Hydro committed to and implemented a process for deferring disconnection for low income customers that have applied (or are about to apply) for social assistance or a crisis supplement until MSDSI completes its review. This is below in section 5.4.3 below with respect to the OEB Low Income Rule concerning the mandatory suspension of disconnection process for 21 days if an Ontario social agency advises that the low income customer may be eligible for emergency assistance.

Reduced Number of Disconnections - File status is now reviewed during daily conference calls between BC Hydro's collections team and MSDSI's Employment Assistance Workers. During the first three months of operation it was estimated that 60 per cent of crisis supplement applications were discussed through this channel, with the result that fewer low income customers were disconnected – in addition to the avoided inconvenience, this also saved those

[17] MSDSI's BC Employment and Assistance (**BCEA**) Summary Report - Cases by Program and Family Type – October 2015, found at: http://www.hsd.gov.bc.ca/research/keyfacts.pdf, shows that as of October, 2015, there were a total of 136,435 BCEA cases (households) and 177,474 BCEA clients throughout B.C.

customers from paying the Minimum Reconnection Charge once MSDSI approved the crisis supplement and service was reconnected.

Security Deposit Waiver - BC Hydro and MSDSI are also developing a process for waiving security deposits for MSDSI's Direct low income customers. BC Hydro has a low risk of bad debts for these customers because payments are coming from MSDSI directly. MSDSI has also suggested that if an Indirect client was assessed a security deposit it would extend the offer to make payments directly on the client's behalf to have the deposit waived.

Future Steps - BC Hydro and MSDSI are currently developing an additional Information Sharing Agreement to help the process for the waiving of security deposits for MSDSI clients that receive a Final Notice of Disconnection with a security deposit warning. The potential for a further Information Sharing Agreement has been discussed in the context of enabling enhanced analysis of payment histories of low income customers, as identified in section 5.5 below.

4.3 BC Hydro Collections Performance

The discussion in section 5.3 considers the cost effectiveness of BC Hydro's collection processes, and if cost-effectiveness would be improved if low income terms and conditions were introduced. Accordingly, it is useful to understand BC Hydro's approach to collections, as well as the performance of the collections process over the past several years.

Because electricity is consumed before it is billed, utilities have limited methods available to manage the risk of non-collection. In general, collections for active accounts are managed through 'Dunning' notices and ultimately the disconnection of service. ('Dunning' is the commonly-used term to describe the process of communicating with customers to ensure collection of accounts receivable). Risks of future non-payment on closed accounts are mitigated through security deposits, while collection agencies and the potential to transfer outstanding balances to new accounts provide additional opportunities for reducing uncollectable revenues that are expensed as bad debts.

Dunning Notices and Disconnections –The objectives of the dunning process are to maximize the collection of billed revenue and to prevent accounts from continuing to accrue outstanding balances that cannot be collected and must be expensed as bad debts.

BC Hydro's dunning process involves the following progressive warnings:

- Late Payment Reminder;
- Important Notice;

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- Final Notice of Disconnection, and
- Agent phone call or auto-dialer message.

The customer's account is then disconnected if:

- The outstanding balance exceeds $70; and
- Payment has not been received or reported; or
- An installment plan or other payment arrangements has not been created.

Customers that have a good payment history will receive all four of these warnings, and disconnection would not occur until the account has been in arrears for more than two months. However, a customer with a bad payment history would first receive the Final Notice of Disconnection and could be disconnected after three-weeks in arrears.

Refer to Exhibit B-5, BC Hydro's response to BCOAPO IR 1.178.1 for a detailed summary of Dunning actions and timelines.

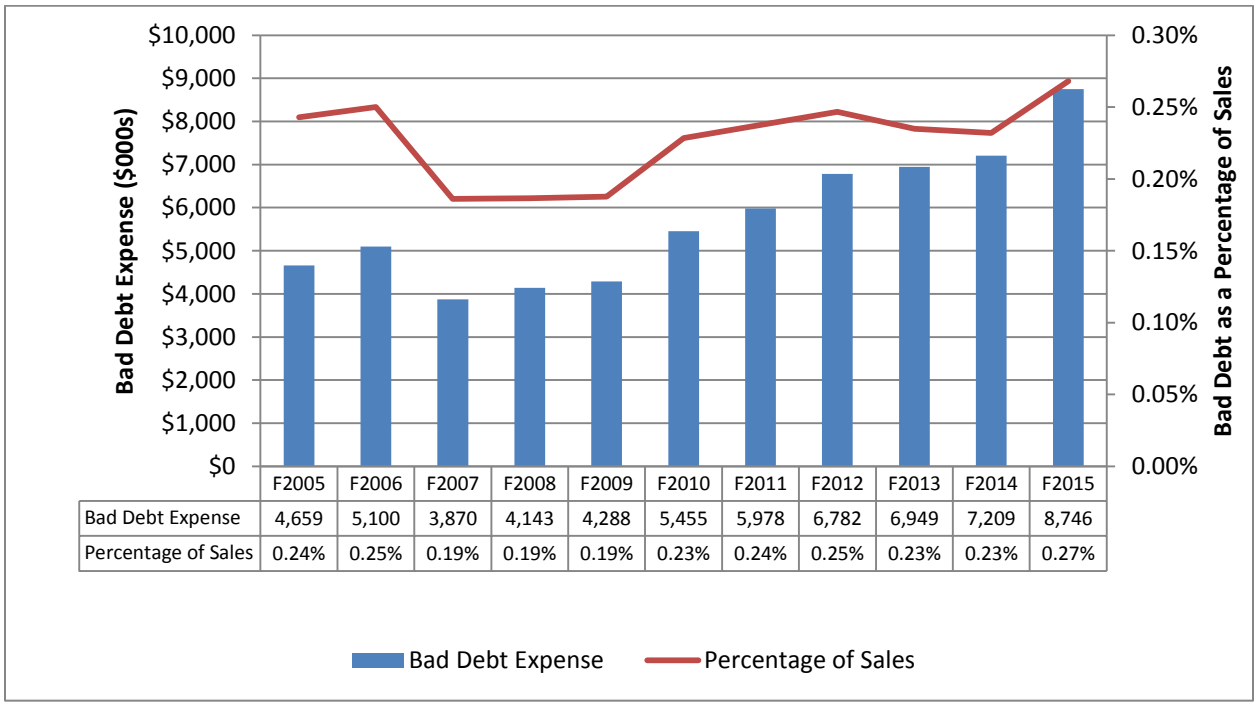
Bad Debt - Bad debt expense is comprised of four components:

- Immediate write-offs of revenue from accounts that declare bankruptcy;
- A gradual write-off of accounts that are closed by customers and for which the customers do not pay the final outstanding balance;
- A gradual write-off of accounts that are closed by BC Hydro because they were disconnected for non-payment and were not reconnected, or because they did not inform BC Hydro they were terminating service and another customer took responsibility for the premises; and
- Changes in the balance sheet provision for bad debt based on periodic assessments of payments and collections performance.

Bad debt expense is measured both in dollars and percentage of sales (lagged by eight months). As shown in Figure 1, the total residential and commercial bad debt metrics increased in F2010 as compared to the prior years – this is attributed to poorer economic conditions as compared to the preceding years, but is also consistent with bad debt performance prior to F2007. Since F2010, bad debt has increased in dollar terms but remained relatively constant when expressed as percentage of sales, which normalizes for customer growth and general rate increases through RRAs.

The increase in F2015 bad debt expense is attributed to the reasons discussed below with respect to aged receivables.

Figure 1: Bad Debt Expense by Fiscal Year



	F2005	F2006	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015
Bad Debt Expense	4,659	5,100	3,870	4,143	4,288	5,455	5,978	6,782	6,949	7,209	8,746
Percentage of Sales	0.24%	0.25%	0.19%	0.19%	0.19%	0.23%	0.24%	0.25%	0.23%	0.23%	0.27%

Aged Active Accounts Receivables (**A/R**) – the number and amount of receivables remaining uncollectible after 60 days – followed a similar trend to bad debt. While there are seasonal variations in A/R for residential customers (as a result of higher bills during winter heating periods), there was an overall increase in Aged A/R for active accounts from F2010 to F2015. This is shown in Figure 2. Consistent with bad debts, Aged A/R is expressed in absolute dollar amounts as well as normalized for general rate increases.

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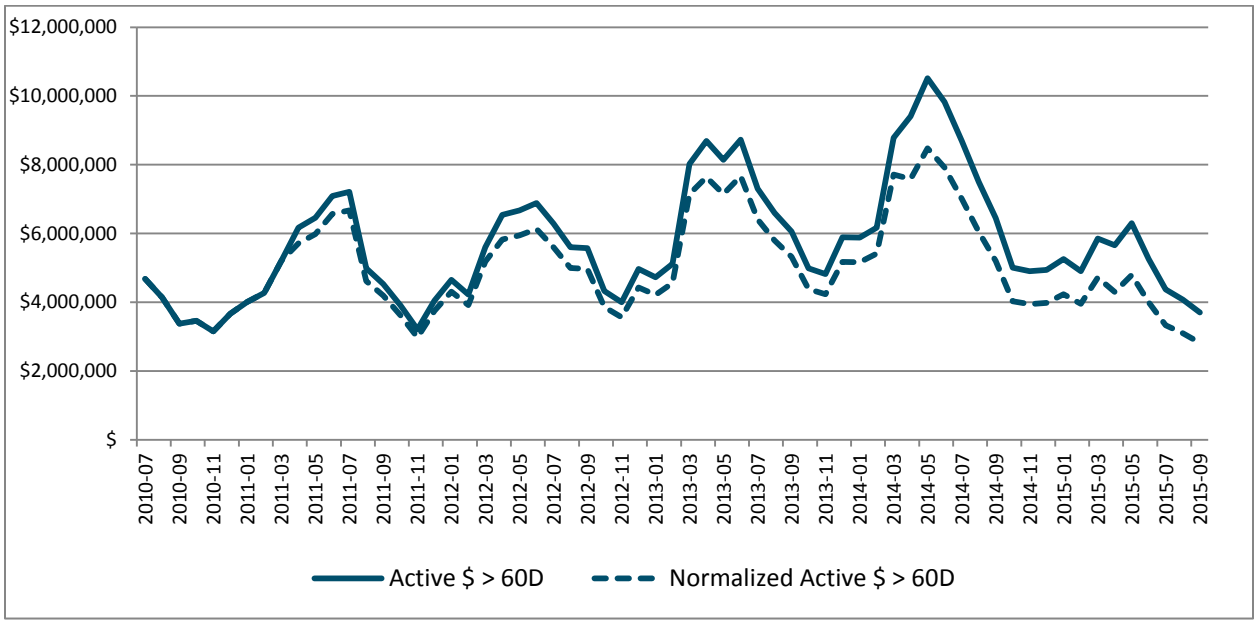
Figure 2: Active Receivables Aged 60+ Days (Residential Electricity Charges)



Managing active A/R is important to minimize bad debt expense: if receivables on active accounts can be minimized then BC Hydro also limits the magnitude of potential write-offs if the accounts are closed. Accordingly, it is not surprising that the increases in bad debts shown in Figure 1 correspond with the increase in Aged A/R for active accounts.

BC Hydro's analysis indicates there are several reasons for the increases in bad debts and Aged A/R for active accounts, including:

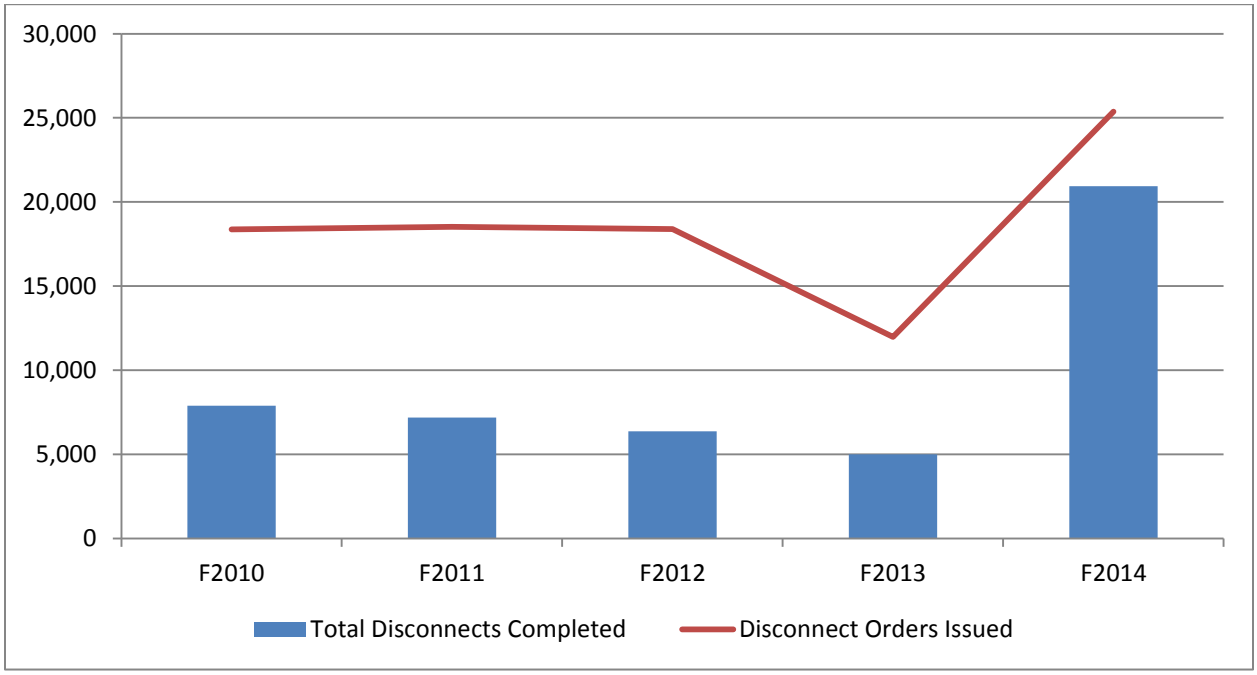
1. High consumption accounts – In calendar 2014, one per cent of residential accounts resulting in bad debt had average monthly bills of over $500; however, these accounts totaled 19 per cent of the total residential bad debt. BC Hydro has evidence to suggest that many of these accounts were marijuana grow operations that signed up for service (i.e., rather than stealing electricity) but did not pay their final months' bills. [Refer to BC Hydro's response to BCUC IR 1.135.3];

2. Ineffective security deposits for small accounts – To reduce administrative burden, BC Hydro's business practice has been to not request security deposits for new accounts unless the deposit totals at least $110. This means that most small accounts – predominately apartments – did not have security deposits applied. However, the analysis indicated that apartments comprised 54 per cent of accounts resulting in bad

debts, despite just 27 per cent of residential accounts classified as apartments. [Refer to the assessment provided in BC Hydro's response to BCOAPO IR 1.198.2];

3. Transition to automated meter readings and remote disconnect/reconnect – Prior to the introduction of Remote Disconnect/Reconnect (**RDR**), BC Hydro had a low success rate in being able to disconnect customers once a disconnect order was issued. This condition was exacerbated in F2013 as credit activities were impacted by the introduction of smart meters, the transition of the meter reading workforce to automated meter reading, and stabilization of the smart metering communications infrastructure to enable RDR. Without an effective method of disconnecting customers during this period, BC Hydro had less ability to manage its outstanding accounts. See Figure 3.

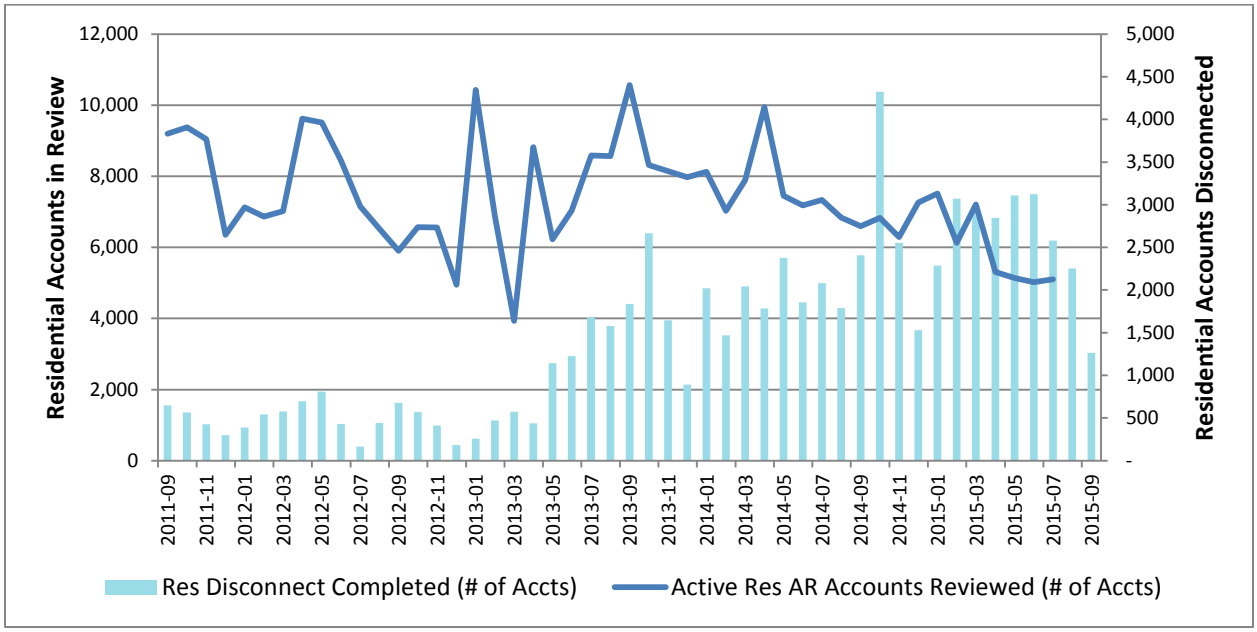
Figure 3: Disconnection Orders and Disconnections Completed, F2010 to F2014



As a result of this deteriorating performance, in Quarter 2 of F2015 BC Hydro placed additional focus on managing Active A/R by making several improvements to its automated 'credit analyzer', developing new processes for reviewing high consumption accounts and ensuring that credit review backlogs were cleared. This resulted in the start of significant improvement in the Aged A/R as shown in Figure 2 above.

Also, as shown in Figure 4, the number of residential accounts 'in review"' has decreased to its lowest point in the past four years. Accounts 'in review' are at an advanced stage in the dunning process (i.e., Final Notice of Disconnection has already been issued) and are being reviewed by credit agents for disconnection. This stage involves the final contact with customers so they may enter into payment arrangements rather than having service interrupted. Based on discussions with other utilities using RDR, BC Hydro anticipated that collections activities would eventually decrease as customers learned that BC Hydro was able to complete disconnections in a timely manner and so would start to prioritize payment of electricity bills. The downward trend in accounts in review indicates that this shift in behaviour may be taking hold.

Figure 4: Residential Active Reviews and Disconnections for Non-Payment



This improved performance is also shown in Figure 2 above, which shows that Aged A/R has been significantly lower in 2015 than results from comparable periods in prior years. On a normalized basis, Aged A/R is currently at its lowest level in five years, which again indicates that the recent focus on arrears management has had positive financial impacts.

Although lagged by many months, bad debt performance has improved significantly from F2015. Based on actual F2016 results to the end of November, BC Hydro is forecasting a year-end bad date expense of 0.23 per cent of sales, which is consistent with historical averages. Bad debt accounting practices vary but through conversations with other Canadian electric utilities

BC Hydro notes that BC Hydro's bad debt performance is average to above-average in comparison with peers.

5 Assessment of Potential Low Income Terms and Conditions

5.1 Administrative Costs and Determining Eligibility

The cost of identifying residential customers as being Eligible Low Income Customers is one of the key difficulties concerning the extent to which BC Hydro can or should be required to implement low income terms and conditions. If administrative costs to BC Hydro are disproportionately high then the benefits of implementing such programs could be reduced or lost.

This section discusses potential costs and methods of determining customer eligibility. It also discusses the privacy implications of obtaining income data and other personal information from customers that in absence of low income terms and conditions would not be required by BC Hydro to provide electricity service. The section also addresses a number of IRs submitted by BCUC and BCOAPO related to eligibility processes and privacy concerns.

Determining Eligibility

Confirmation of income eligibility is necessary for any proposed Terms and Conditions applied only to low income customers, namely the waivers on Security Deposits, Late Payment Charge and Minimum Reconnection Charge. Confirmation is not required for terms and conditions available to all customers (i.e., winter disconnection moratorium, flexible payment arrangements) or policies related to the circumstances of a specific customer that would be verified separately (i.e., disconnection grace period when applying for assistance, medical emergency).

BC Hydro assumes that the eligibility of a customer for low income terms and conditions could be determined in several ways, including:

1. Confirmation from MSDSI or other acceptable government programs

   MSDSI indicated it has approximately 130,000 clients receiving some form of income assistance. While not all MSDSI clients are located in BC Hydro's service area and others may not actually be BC Hydro account holders, it is possible that up to two-thirds of customers with household incomes below LICO could be identified from MSDSI's client list.

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Eligibility could also be established through participation in other recognized programs using the DSM Regulation approach discussed above.

2. Online Program Applications

For the new Ontario Electricity Support Program (**OESP**) directed by the Ontario Minister of Energy,[18] the OEB created an online application form that is integrated with Canada Revenue Agency (**CRA**) to validate income. A similar approach could be implemented if warranted by the nature of the programs and the number of customers that may not already be identified through MSDSI or other governmental program.

3. Third Party Intake Agencies

Ontario's LEAP established a network of external intake agencies to determine eligibility; this network will continue under OESP, for customers unable to apply online. Intake agencies include large organizations such as United Way, Salvation Army and YMCA, as well as smaller community-based groups.

4. Direct Application to BC Hydro

BC Hydro has already created processes to validate eligibility for its low income DSM programs. Although BC Hydro would prefer not to undertake eligibility reviews for low income Terms and Conditions, this is an option.

All of these options will require the development of new business processes and technology. Administrative costs can be reduced by linking eligibility to participation in programs operated by government agencies such as MSDSI; however, incremental costs cannot be eliminated for a number of reasons:

- At most, only two-thirds of the eligible low income customers would be clients of MSDSI. Other sign-up procedures would necessary to verify eligibility for the remainder;

[18] On 23 April 2014 the Ontario Minister of Energy pursuant to section 35 of the *Ontario Energy Board Act* requested the OEB's advice on an electricity rate/affordability program for low income electricity customers. Refer to BC Hydro's low income rate/low income terms and conditions/low income DSM program jurisdictional review at Exhibit B-1, Appendix C-3D, page 19 of 29. As noted in BC Hydro's response to BCOAPO IR 1.98.1, the Ontario government introduced legislation to enable implementation of the OESP. Schedule 31 of the *Building Ontario Up Act (Budget Measures, 2015* amended the *Ontario Energy Board Act* by introducing section 79.2 authorizing the OEB to make provision for rate assistance to rate-assisted customers having regard to their economic circumstances in approving just and reasonable rates for an Ontario utility distributor.

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- Program participant lists are not static – they constantly change as clients enter or leave their programs. Accordingly, IT systems must be integrated such that eligibility is kept up to date;
- Additional effort would be required to link any agency's or program's client lists with BC Hydro accounts. This is not done currently except for customers having their electricity bills paid directly by MSDSI;
- While it is assumed that many of the accounts could be matched automatically based on name and service address, there are situations in which eligibility would require additional investigation (e.g., the BC Hydro account is registered to a family member of the MSDSI client);
- Budget-constrained governmental agencies may require a contribution towards the costs they incur to provide data or change business processes;
- Even if third party intake agencies were able to verify income with minimal incremental administrative costs, BC Hydro would still be required to build and maintain the IT tools used by the intake agencies;
- BC Hydro would need to engage in ongoing communications and training with intake agencies, as they would need to be familiar with the low income terms and conditions so that they may better assist low income customers;
- There would need to be upfront and ongoing communications so that customers would become aware of any potential low income programs and take steps to apply; and
- BC Hydro assumes for this review that it would be its responsibility to provide Eligible Low Income Customers with access to the applicable low income terms and conditions. Eligible Low Income Customers would contact BC Hydro to take advantage of some or all of the low income terms and conditions, which would increase call centre and correspondence costs.

It is also possible that the same systems could be used to determine eligibility for low income DSM programs, provided that procedures reflected the differences in household income (i.e., LICO vs. 130 per cent of LICO). However, the upfront implementation costs of billing system changes would increase with the number of Terms and Conditions or rates affected. [Refer to BC Hydro's response to BCUC IR 1.97.1].

Once income is verified it would be not be necessary to re-verify the customer's eligibility within a defined time period (e.g., two years). Instead, the customer's account record would be flagged as being a "Confirmed Low Income Customer" and automatically made eligible for terms and conditions during the period of eligibility. BCOAPO communicated that in addition to

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verifying eligibility, flagging customers as "Confirmed Low Income Customers" would also be used to convey to BC Hydro's customer service staff that a customer is low income and may need some specialized assistance. BCOAPO also communicated that if BC Hydro or the BCUC is concerned about the two-year eligibility period being too lengthy, BCOAPO would support spot audits being completed for a percentage (7-10 per cent, for example) of Confirmed Low Income Customers on an annual basis.

Implementation Costs

Upfront investments in business processes and IT systems will be necessary regardless of which organization performs the review. BC Hydro prepared a high-level cost estimate of an eligibility program, as shown in Table 3. This estimate assumes that eligibility is verified through intake agencies. Please note that this was prepared for the purpose of a ballpark budgetary estimate – a more accurate estimate would not be possible until specific program criteria and requirements were identified:

Table 3: Potential Low Income Terms and Conditions Implementation Costs

Item	High-Level Cost ($000s)
Billing System Enhancements	$800
System Integration with Intake Agencies	$400
Process Design and Agent Training	$50
Total	**$1,250**

The above estimate does not include any changes to bchydro.com or interfaces to CRA to enable online income verification.

Ongoing operational costs will also be incurred by both BC Hydro and the intake agency/agencies. BC Hydro estimates that its incremental operational costs to support low income Terms and Conditions would be $0.4 million annually.

Privacy Implications

In BC Hydro's response to BCUC IR 1.44.1, BC Hydro notes that it is subject to the B.C. *Freedom of Information and Protection of Privacy Act* (***FOIPPA***) and, as such, is required to protect personal privacy by preventing the unauthorized collection, use or disclosure of personal information. A Privacy Impact Assessment has not been completed for proposed low income terms and conditions but, in general, the following issues would need to be addressed to ensure compliance with *FOIPPA*.

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FOIPPA does not restrict public bodies from collecting personal information such as household income where it is necessary for the operation of a legally authorized program. However, it is necessary for the individual to consent to its use. There are also strict protocols that must be followed to ensure that personal information is protected from unnecessary access, or from unauthorized use or disclosure.

In this instance, customers would need to provide consent for the collection and use of the personal information for the purpose of enrolling in a low income program. If eligibility is verified by MSDSI or a third party, the customer would also have to provide consent for those agencies/organizations to share required information with BC Hydro.

The need to obtain consent could limit the ability for any low income term and condition to be introduced without making it voluntary. This would potentially be the case even for low income customers already receiving MSDSI assistance – while their application to MSDSI includes consent that necessary personal information can be shared with utilities, it is uncertain if the terms of consent for existing clients would allow BC Hydro to enrol them in a low income terms and conditions without further consent being provided. However, going forward, changes could be made to MSDSI's consent form. It is also possible to argue that disclosure of MSDSI client lists is warranted because it would be done for the benefit of affected individuals.

It is noted that with up to 170,000 customers potentially eligible for low income terms and conditions, it would be necessary to develop forms of automated data transfers with any government agency or external organization involved in confirming eligibility. BC Hydro would need to create Information Sharing Agreements with these organizations.

BC Hydro already has safeguards on its customers' personal information; however, the collection of income information may necessitate changes to some business practices. Access to a customers' personal information is on a 'need to know' basis and regulated through user profiles and IT security features. The need for additional security with respect to low income eligibility indicators would be reviewed during the Privacy Impact Assessment.

For operational purposes, BC Hydro would only need to know that the account is eligible for low income Terms and Conditions:

- Income data would not be kept in the billing system – call centre agents would only see a flag indicating eligibility;

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- Privacy risks can be minimized through limited access and secured storage of documentation of a customer's proof of family income:
    - If eligibility was determined by BC Hydro, a specialized team could be used to verify income so as to restrict access to detailed income information;
    - As being implemented for OESP in Ontario, customers applying online would not need to share their income information with BC Hydro or other agency provided that the automated income verification with CRA was successful.

The Office of the Information and Privacy Commissioner would be consulted to obtain its feedback for the adequacy of procedures and adherence to *FOIPPA*.

These procedures are consistent with how BC Hydro manages its ESK and ECAP programs. Applications, which include household income, include terms and conditions that provide customer consent for the collection and use of personal information for the purpose of determining ESK and ECAP eligibility. Consent is also granted for sharing of required data with FortisBC, as applicable when the customer's premises is heated by natural gas.

The applications are processed by a small operations team so as to limit the visibility to personal information not otherwise required for BC Hydro's operations. Only the results of the application (i.e., eligible or not eligible) and not the customer's actual income are then added to the customer information system and made available to the customer service representatives in the event that the customer has an enquiry. [Refer to BC Hydro's responses to BCOAPO IRs 1.109.16 and 1.109.17].

Similar processes are used when applications are being submitted by First Nations governments or community-based social agencies on behalf of their members. Consent is first obtained from the BC Hydro account-holder, indicating that he or she is willing to have their account information shared with the organization, as well as that the organization has authority to act on their behalf. The customers' personal information may then be shared with the organizations, typically using encrypted email and password protected files to maintain privacy.

BC Hydro does note, however, that it can only maintain the privacy of personal information it has in its custody. Despite the existence of Information Sharing Agreements or other established protocols, BC Hydro cannot prevent unauthorized disclosure of a customer's personal information held by another organization.

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5.2 Cost-Benefit Analysis

As noted in section 3 above, BC Hydro incurs costs of approximately $20 million annually because of late payment and non-payment from residential customers. In BC Hydro's view, the introduction of low income term and conditions will not completely offset BC Hydro's costs. For example, late payment communications and payment arrangements would continue, and a percentage of revenue would still be written-off as bad debts. Therefore, low income terms and conditions are not supported through a benefit-cost analysis in which implementation and operational costs would be offset by savings. This is particularly the case if potential increases to bad debt expenses are considered.

5.3 Cost-Effectiveness Analysis

BCOAPO communicated that BC Hydro should assess the proposed terms and conditions in light of both the effectiveness and efficiency of collections. BCOAPO contends that low income terms and conditions can be expected to improve the productivity of collection activities from two different but related perspectives. On the one hand, the terms and conditions will affect how much revenue (outputs) is generated by each collection intervention. On the other hand, the terms and conditions will affect how many collection activities (inputs) are needed to generate the revenue.

BC Hydro agrees with this proposition in concept. It is logical that spending money on notices or customer contacts is pointless if the customer does not have the ability to pay. Similarly, if a customer does not have the ability to pay, conceptually, it makes sense that credit and collection responses that further increase a customer's bill may not be productive.

With this in mind, BC Hydro has assessed the overall level of its collections activities to determine where such activities are cost effective. There are, however, it faces two key constraints in performing this analysis:

1. BC Hydro does not have customer data that allows payment performance and collections activities to be assessed based on income; and
2. The standard reports available from its billing system were not developed for the purpose of this analysis. Accordingly, the necessary data is not readily available.

These constraints notwithstanding, the following analyses have been undertaken to provide indications of the cost-effectiveness of BC Hydro's collection processes, as well as to the degree in which low income terms and conditions could improve their effectiveness.

BC Hydro also notes that it has only assessed the actions and impacts from within its mandate of collecting revenue for electricity consumed; external costs and social impacts are not reflected.

Credit Action Effectiveness

BC Hydro monitors the effectiveness of its individual collections activities by identifying the percentage of customers that paid their outstanding balances within seven days of the applicable notice. As shown in Table 4, each individual activity has an effectiveness of up to about 50 per cent.

Table 4: Credit Action Effectiveness

Action	Effectiveness (F2016 to Oct 31)
Letter - Reminder	51.0%
Letter - Important Notice	39.8%
Letter – Final Notice of Disconnection	47.7%
Letter – Final Notice of Disconnection with Security Deposit Assessment	29.5%
Phone Call – Agent Contact	48.7%
Phone Call – Autodialer	45.0%

Each of the actions is cost effective when considered for the full population of Residential accounts given that the costs of the actions range from $0.89 for printing and mailing of a notice to $3.80 for an operator review. For instance, for a $30 outstanding balance, a reminder letter would only need to have a $0.89 / $30 = 3 per cent success rate to be considered effective.

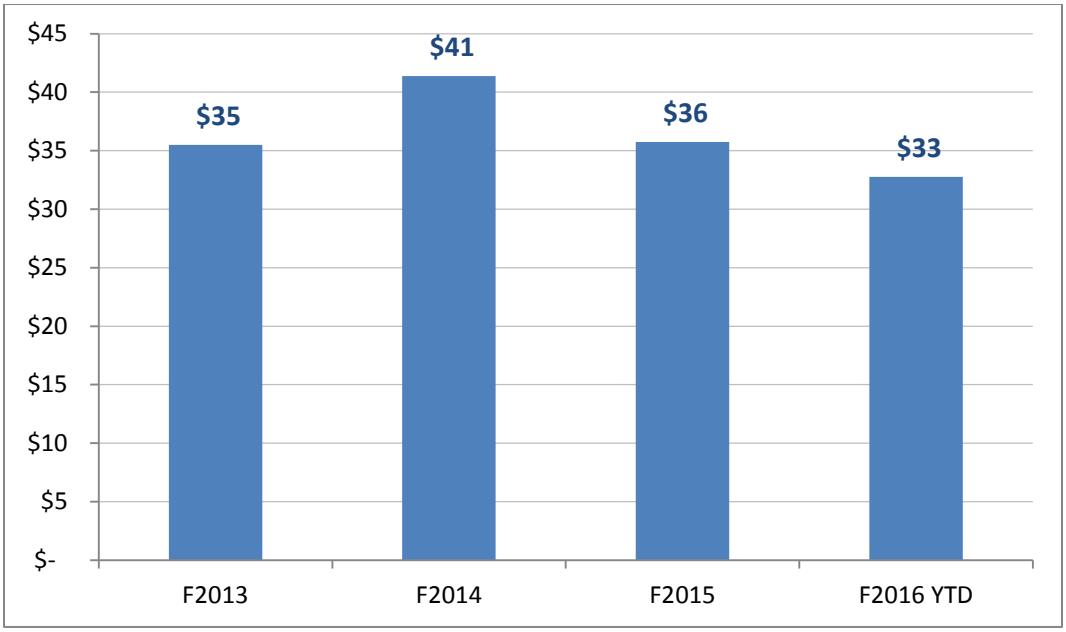
BCOAPO indicated that it does not consider this approach to be an accurate measure of the effectiveness of collections activities because it assumes that all payments occurring after a collection activity occur because of the collection activity, although some of those payments would have occurred irrespective of the collection activity. BC Hydro acknowledges this concern and agrees that it is not a definitive 'cause and effect' view of how effective each action is on its own. However, in absence of having a more detailed understanding of what caused each customer to make his or her payment, BC Hydro believes it does provide directional information that can be trended over time.

Collections per Dollar Spent

The effectiveness of the Dunning process can be measured through the amount of revenue collected from each dollar spent. For this analysis, BC Hydro compared the reduction in Active A/R (over 30 days) to the cost of collection activities (Dunning and disconnection).

BC Hydro's response to BCOAPO IR 1.201.1 shows that the average weighted cost of Dunning and disconnection is $15.94. However, as shown in Figure 5, each dollar spent on collections for aged active residential receivables results in payment of over $33. Therefore, BC Hydro's current collections practices are cost-effective when viewed on the basis of average costs and returns.

Figure 5: Residential Revenue Recovered per $1 Collection Cost



The downward trend reflects that prior to smart meters BC Hydro was unable to successfully disconnect many accounts before they became 'stale' and needed to be reviewed a second time. This meant that high dollar accounts received the primary focus for operator reviews. However, given the high success rate of RDR, collection agents are able to review more files (as shown in Figure 4 above) and more notifications are being sent. This has decreased the average amount collected per dollar spent.

BC Hydro acknowledges BCOAPO's concern that this approach is not a measure of the marginal effectiveness of its collections actions. A more comprehensive, scientifically-based evaluation would be necessary to determine the optimum level of collections efforts for different customer segments and whether BC Hydro has reached or exceeded that point.

Customer Payment Behaviour

Residential arrears data assessed over a number of years to determine customer payment behaviour and whether or not customers ultimately paid their bills. This was viewed from several perspectives.

Table 5 indicates the average percentage of Residential accounts that were paid within 30 and 60 days. As Dunning activity does not start until Day 28, the 30 day figure is essentially an analysis of on-time payments.

Table 5: On-time Payments

Percentage of Accounts Paid Within:	F2012	F2013	F2014	F2015
30 days	84.2	83.8	83.5	84.4
60 days	96.3	95.9	95.6	96.4

Table 6 indicates the percentage of residential accounts that were in arrears at Days 30-59 but were paid by Day 150.

Table 6: Payment of Arrears

	F2012	F2013	F2014	F2015
Percentage of Accounts in Arrears Day 30-59	15.8	16.2	16.5	15.6
Percentage of Above Arrears Cleared by:				
120 days	84.5	82.5	82.2	84.4
150 days	91.2	90.3	89.7	90.6

Table 7 indicates the number of disconnection orders issued as compared to the overall number of residential customers.

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Table 7: Disconnections for Non-Payment

	F2012	F2013	F2014	F2015
Residential Accounts	1,671,412	1,689,050	1,727,945	1,709,071
Number of Disconnection Orders	18,381	11,987	25,362	38,781
Percentage of Accounts Receiving Disconnection Orders	1.1	0.7	1.5	2.3
Number of Disconnections Completed	6,376	4,995	20,940	32,564
Percentage of Accounts Disconnected	0.4	0.3	1.2	1.9

In addition, BC Hydro notes that nearly all customers that are disconnected for non-payment in F2015 were eventually able to re-establish service. As set out in the Workshop 9A consideration memo (Exhibit B-1, Appendix C-3B, page 361 of 609) in F2015:

- 54.5 per cent of accounts were reconnected the same day;
- 84.7 per cent were reconnected within 7 days;
- 91.6 per cent were reconnected within 21 days;
- 96.6 per cent were reconnected within 60 days, and
- 99.0 per cent were reconnected within 133 days.

Although it is difficult to draw sound conclusions from the above statistics, the general assessment is that nearly all customers are ultimately able to pay their outstanding balances, even if their arrears reached the point that their service was disconnected. As such, the costs of Dunning notifications and service disconnection appear to be warranted.

Conclusions

While there are still opportunities to increase the productivity and effectiveness of collections processes, BC Hydro is of the view that:

- A benefit-cost analysis does not support a reduction in collection actions overall;
- With respect to cost-effectiveness, given that there is insufficient information currently available to enable increased targeting of actions for low income customers, it is difficult to reach a conclusion on whether a set of low income terms and conditions is a

cost-effective response to collection and credit costs. In BC Hydro's view, any savings on collections and credit costs is likely to be modest, and will not offset the entire amount of foregone billings.

BC Hydro notes:

- BC Hydro will continue to incur costs notifying customers of outstanding balances;
- Cost savings have been achieved – and will continue to be achieved – through automation of credit reviews, use of electronic channels (i.e., email) for collection notifications, and increased alignment of Dunning messaging with customer billing cycles; and
- With RDR, the majority of customers can be disconnected remotely with minimal incremental cost.

Recognizing that an average expenditure of $15.94 (i.e., Dunning plus disconnection) leads to payment in nearly all cases, BC Hydro contends that its collections processes are effective and that financial and operational performance would not improve significantly if BCOAPO's proposed terms and conditions are adopted.

Given that BC Hydro cannot definitively conclude that low income terms and conditions are a cost-effective response to bad debt and collection costs, and given BC Hydro jurisdictional assessment and discussions with BCOAPO, BC Hydro assessed each of the proposed low income terms and conditions.

5.4 Assessment of Each Proposed Low Income Terms and Conditions

This section provides BC Hydro's assessment of the impact of each proposed low income term or condition.

5.4.1 Security Deposit Waiver

As noted in Table 1 above, the OEB Low Income Customer Rules provide that an Eligible Low Income Customer is granted a waiver of the security deposit upon request. If already paid, the Eligible Low Income Customer can request the return of the security deposit if there are no arrears on the bill.

<u>BC Hydro Assessment</u>

BCOAPO stated that the objective of a cash security deposit is only to mitigate the risk that a customer does not pay its final bill in full and that not all nonpayment indicates or leads to such

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risk. BC Hydro agrees with this statement; however, as a customer's ability or motivation to pay his or her final bill is unknown, BC Hydro must judge the risk of non-payment either from the credit rating (for a new customer) or recent payment history (if an existing customer).

This notwithstanding, BC Hydro analyzed Residential closed accounts, bad debts and security deposits from 2010 to 2014 and identified that current security deposit practices are largely ineffective. Of findings relevant to this proposal:

1. Security deposits are not assessed from the right customers:
   a. Only 13 per cent of new residential accounts had initially been assessed security deposits;
   b. Apartments are 27 per cent of total accounts but are 54 per cent of the total accounts in bad debts;
   c. 83 per cent of closed accounts with aged balances had never been assessed a security deposit.

2. Security deposits are not held long enough:
   a. 97 per cent of security deposits collected from new or deteriorating accounts were reversed or returned before the accounts were closed'
   b. The average account length for an apartment was 14 months but security deposits are returned after 12 months.

The review is included in BC Hydro's response to BCOAPO IR 1. 198.2.

Conceptually, a reduction in security for Residential accounts (for new accounts and deteriorated payment history) would increase bad debts but also decrease interest paid on security deposits that are held. However, in view of the above analysis, BC Hydro recognizes it could sharpen its business decision rules for determining when a deposit should be required without adversely affecting bad debt expense.

BCOAPO stated that security deposits may be counter-productive to the collection of bills when customers cannot afford to pay their bills. A low income customer who has experienced a disconnection of service would face not only the financial burden of paying the unpaid bills that led to the disconnection in the first instance, but the additional financial burden of paying a new deposit. The deposit, rather than protecting the company, could represent an insurmountable barrier to the customer, thus both harming the customer and preventing the company from collecting the outstanding amount. BC Hydro acknowledges this concern.

The above analysis and findings, as well as comments from BCOAPO, are the underlying reasons why BC Hydro proposed increased flexibility in how it applies security deposits.

As noted in section 4.2, BC Hydro has been working with MSDSI to enable the waiver of security deposits for customers receiving (or who ask for) direct payment of their electricity bills. BC Hydro's rationale for waiving deposits is that these customers do not pose unacceptable financial risks because involvement of MSDSI provides a form of assurance that bills will be paid.

BCOAPO has also suggested that BC Hydro provide alternatives to the posting of a cash security deposit that would serve the company's interest while recognizing the customer's inability to pay. These could include actively promoting more guarantors such as by community-based organizations in addition to MSDSI. BCOAPO has also suggested mandatory participation in an Equal Payment Plan beginning in a low-cost month. BC Hydro agrees there is merit in these ideas and will investigate opportunities further.

These factors and opportunities notwithstanding, there are a number of drawbacks in making a security waiver mandatory for all low income customers:

- A mandatory waiver would leave BC Hydro with no security for new customers that have poor credit ratings, as well as for existing customers that have demonstrated poor payment history;
    - These are the customers that based on recent payment history BC Hydro would characterize as being at risk of non-collection of final bills;
    - Without security deposits, BC Hydro has no ability to recover revenue in the event the customer defaults; and
- There are administrative costs of this alternative, specifically:
    - Eligibility validation; and
    - Modifications to Dunning processes such that security deposits are not automatically assessed if non-payment would trigger otherwise trigger this outcome.

<u>BC Hydro Proposal</u>

BC Hydro recognizes:

- Forms of security beyond cash deposits can be as or more effective in mitigating risk of non-payment of final bills. In particular, forms of guarantees such as that provided by

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MSDSI for its Direct payment clients are preferred because they balance BC Hydro's need to mitigate risk with the customer's benefit of an avoided cash payment;

- There are shortcomings in its application of security deposits and so, as described in section 8.4 of Exhibit B-1, BC Hydro proposes amendments to security deposit-related provisions in section 2.4 of the Electric Tariff to provide BC Hydro with flexibility in the amount assessed, and to enable changes in business practices.

If these Electric Tariff proposals are approved, specific business practices changes being considered and affecting low income customers include:

- All new Residential customers without established credit will be assessed a security deposit equal to one-time their average monthly bill, rather than two- or three-times as is currently required under the tariff. For new customers in apartments, the security deposit will be established as a standard $50;

- A graduated approach will be used to assess security deposits for existing residential customers with deteriorated credit worthiness. In the first instance, a customer will be assessed a security deposit of one-time their average monthly bill, rather than two- or three-times as is currently required under the tariff. The security deposit would be increased later if the customer continues to exhibit poor payment history;

- Security deposits will be waived for low income customers whose payments are being made by MSDSI (e.g., Direct, about 6,000 customers). An amendment to section 2.4 of the Electric Tariff would not be required for situations in which MSDSI guarantees the Eligible Low Income Customer's payments over the period that MSDSI is providing assistance because the requirement in section 2.4 of the Electric Tariff regarding satisfactory credit history would be met. Refer to section 2.2 for an update of the work BC Hydro has done with MSDSI;

- BC Hydro is exploring waiving security deposits for MSDSI Indirect clients (about 124,000 of BC Hydro's low income customers). Implementing such a waiver would require BC Hydro comparing client files with MSDSI and matching such files with accounts. A method of adopting such waiver would be to amend section 2.4 of the Electric Tariff along the lines of NSPI's Regulations (refer to Table 1 above), that is, provide the waiver to MSDSI Indirect clients but require a deposit if, following the waiver, the MSDSI Indirect customer subsequently defaults in payment or is seeking reconnection

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following disconnection for non-payment and had a security deposit previously waived respect to the account that was disconnected. BC Hydro is in the process of gathering information from NSPI, and through further discussions with BCOAPO, provide its proposal on this subject as part of its responses to RDA Round 2 IRs, anticipated to be sometime in March 2016.

If the above is adopted, it would leave approximately 40,000 low income customers (170,000 LICO, subtracting MSDSI 130,000 clients) that could not be granted a security deposit waiver unless the customer's eligibility was verified. BC Hydro does not support extending the security deposit waiver without some other form of guarantee for the following reasons:

- Verifying income would incur administrative costs;
- Proposed changes to security deposit rules as described above would result in less financial burden placed upon them if they were new customers or if they did not have a sustained history of missed payments;
- BC Hydro would not have any form of security for customers with sustained periods of delinquent payments and that otherwise would be assessed the maximum security deposits; and
- Security deposits would be waived if these or other customers became eligible for MSDSI support and met the associated requirements for the waiver.

5.4.2 Flexible Arrears Payment Arrangements

The OEB Low Income Customer Rules provide that an eligible low income customer is granted payment terms of 8-16 months, which is an increase from BC Hydro's typical practice of allowing installment plans of up to 3 months. The OEB Low Income Customer Rules also include:

- a provision to not cancel an installment plan until payment has not been received twice, which is discussed below ,and
- a waiver of the Minimum Reconnection Charge if the customer is disconnected for non-payment, which is discussed in section 5.4.6.

<u>BC Hydro Assessment</u>

Cancellation of Installment Plans

BC Hydro's billing system cancels an installment plan after a single failure, though BC Hydro's business practice is to allow the customer to create new installment plan until there is a

repeated pattern of failed plans. BC Hydro recognizes the customer impact of automatically cancelling an installment plan after the first missed payment and so has included a project to delay cancellation in its billing system work plan for F2017. The need for system changes to improve customer experience notwithstanding, current practice meets the intent of the OEB rules with respect to the cancellation of plans.

Eligibility

If adopted, more flexible payment arrangements would be most effective if made available to all Residential customers, not just those identified as low income. This would eliminate the need for administrative processes to verify eligibility. It also reflects that other customers may also find themselves with unexpected billing adjustments (e.g., Equal Payment Plan anniversary true-ups) or temporary cash flow problems that require payment over a longer period.

Extended Payment Terms

BC Hydro is concerned that extended payment terms sometimes have a negative customer impact in that an outstanding balance from one winter heating period may carry-forward into the subsequent heating period. As shown in Figure 6, average and above-average residential customers have a significant variation in bills between winter and summer periods. In such an instance, the extended payment term can serve to defer, and possibly exacerbate, a non-payment issue. As a result, BC Hydro does not support the concept of installment plans being set for defined time periods, for example for 8 – 16 months depending on the outstanding balance as is required under the OEB Low Income Rules.

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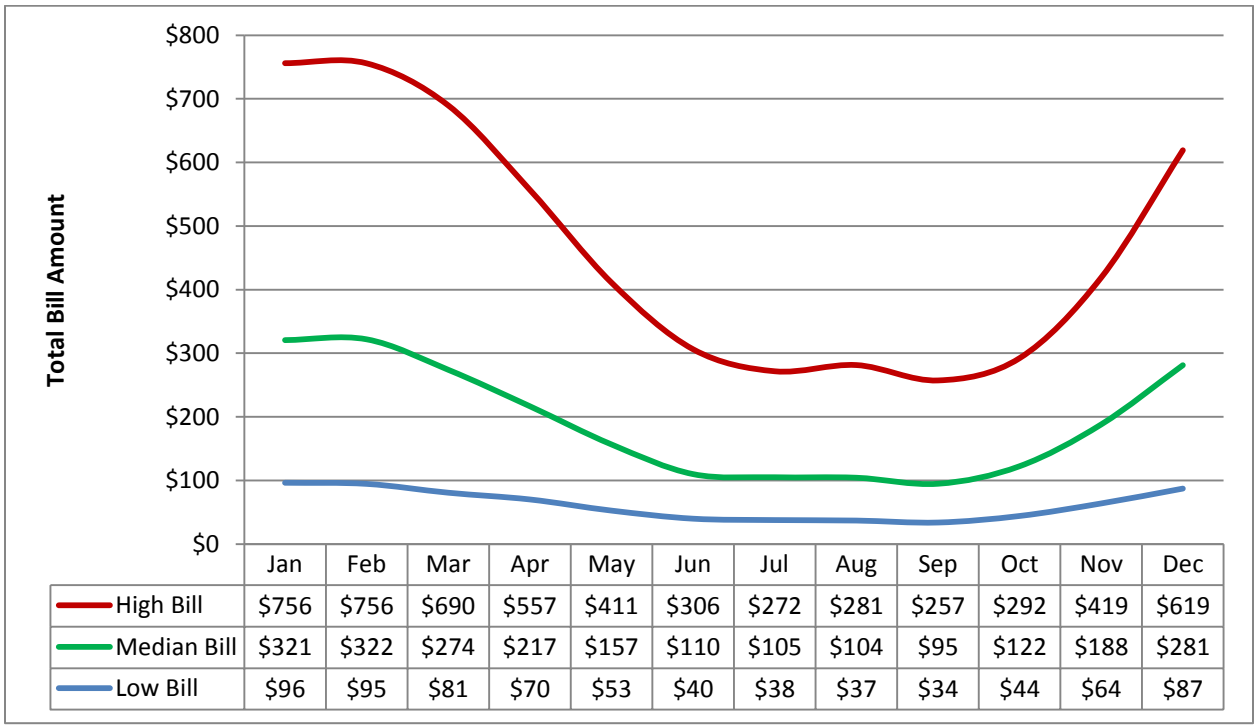
Figure 6: Typical Seasonal Variation in Consumption



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
High Bill	$756	$756	$690	$557	$411	$306	$272	$281	$257	$292	$419	$619
Median Bill	$321	$322	$274	$217	$157	$110	$105	$104	$95	$122	$188	$281
Low Bill	$96	$95	$81	$70	$53	$40	$38	$37	$34	$44	$64	$87

Note: Sample data for an electrically heated, single family dwelling in the Southern Interior. Dates July 2013 to June 2014.

BCOAPO acknowledged BC Hydro's concern about carrying forward debt from one heating season into the next, but also noted that not all payment plans address heating accounts. In addition, BCOAPO stated that the potential additional debt from such a carry-forward situation must be balanced against the non-payment that occurs before the next heating season because a payment plan imposes unaffordable, and unsustainable, bill payment obligations. However, BCOAPO indicated it is open to alternative mechanisms to address BC Hydro's carry-forward concerns through mechanisms such as, for example, mandatory budget billing that would be a part of a payment arrangement initiated in a low-cost month.

BCOAPO also stated that not all "payment arrangements" needing flexible terms must be designed to address unpaid account balances. A flexible structure of budget billing (or equal monthly payment plans) can help prevent unpaid accounts rather than responding to unpaid bills once they have been incurred. Allowing for non-annual budget billing (e.g., six-month budget billing over high cost months) would introduce flexibility; not all customers need or want an annual budget bill, but rather simply need some levelizing of bills over what would

otherwise be high cost months. BCOAPO also suggested placing a cap on payment plan payments, such as having the repayment not exceed an average monthly bill.

BC Hydro agrees while Equal Payment Plans and Installment Plans are useful tools, there are often situations that make them unsuitable for a specific customer's circumstances. BC Hydro also notes that some customer arrears and payment issues are caused by a lack of understanding of Equal Payment Plan status (i.e., is the customer on-track or expected to have a significant true-up bill) or of required payment dates and amounts for Installment Plans.

BC Hydro acknowledges that lack of effective payment options and a confusing bill are contributing factors to these issues. To address these gaps, BC Hydro has a number of billing and payment initiatives planned in the next 3 – 5 years, as noted in BC Hydro's response to COPE 378 IR 1.20.1. Although most of the projects are still in planning phase and haven't been committed for implementation, these projects could assist customer understanding and payment flexibility through enhancements under consideration that include:

- The potential to pre-schedule payments (through a mechanism such as pre-authorized payment) based on dates chosen by the customer. This would help customers avoid missed Installment Plan payments. It could also help to address BCOAPO's comment that customers may simply want to levelize bills over high cost months, by enabling them to create their own version of an Installment plan;
- More clearly identifying dates and amounts for balances included in Installment Plans, as lack of clarity is known to be a reason for missed payments;
- Improved information related to the status of the customer's Equal Payment Plan bank, as well forecasting (based on consumption in the prior year) to clearly identify if there is likely to be a debit or credit applied at the anniversary date;
- The ability to establish Installment Plans through an online, self-service function rather requiring this to be done only by speaking with an agent.

Although a date has not yet been established, potential billing enhancements also include the potential for a pre-paid program within the next five years.

<u>BC Hydro Proposal</u>

Customers receiving direct assistance from MSDSI already receive extended repayment plans for outstanding balances when assistance began. There is limited financial risk in this situation because MSDSI provides payment for current consumption.

BC Hydro recognizes there are situations in which a repayment term longer than three months is appropriate but is opposed to establishing mandatory terms for Installment Plans. Instead, BC Hydro proposes to investigate the practicality of providing collections agents with the authority to offer longer payment terms, for example, up to 6 or 8 months, provided that the outstanding balance would be paid before the next winter heating cycle.

This approach does not eliminate the expectation that collections agents should negotiate the shortest repayment terms appropriate for the customer's circumstance; however, recognizing that this treatment is sometimes offered to customers that escalate complaints, it empowers them (perhaps with a work leader's agreement) to enter into longer agreements while having a better customer experience.

If after investigation such as process remains feasible, BC Hydro would consider implementing it on a pilot basis in F2017 following the 2015-16 winter heating season. Arrears performance would then be reviewed to determine if it would be appropriate to implement this process permanently.

5.4.3 Disconnection Grace Period

BCOAPO's proposal is based on OEB Low Income Customer Rules; there is a mandatory suspension of disconnection process for 21 days if an Ontario social agency advises that the low income customer may be eligible for emergency assistance.

<u>BC Hydro Assessment</u>

No amendment to the Electric Tariff is required to implement this OEB Low Income Customer Rule.

<u>BC Hydro Proposal</u>

BC Hydro concludes that it is not necessary to formally adopt the OEB Low Income Customer Rule. BC Hydro and MSDSI have recently implemented a process to improve communications such that it is easier to identify customers that are applying for support and have been or may be disconnected. These customers will be granted extra time while awaiting MSDSI's response. With this development, BC Hydro has substantially achieved this OEB Low Income Customer Rule.

Disconnections will now be deferred for customers that indicate they are applying for assistance from MSDSI. BC Hydro will apply Interest and Dunning locks for 21 days from the

time that the customer first indicates they have applied or will apply for assistance; however, the 'grace period' will be extended if MSDSI's evaluation takes longer than 21 days.

BC Hydro also notes that Dunning procedures would not normally result in a Residential customer being disconnected with an outstanding balance less than $70 or with fewer than two notifications over a period of at least 21 days.

5.4.4 Winter Disconnections

As set out in Table 1 above, a number of Canadian jurisdictions have winter disconnection moratoriums implemented through policy, tariffs or in the case of Alberta, a regulation. No Canadian jurisdiction has implemented winter disconnection moratoriums solely for low income customers; rather, winter disconnection moratoriums apply to all residential customers.

BC Hydro Assessment

BC Hydro acknowledges that its current practices do not meet the intent of BCOAPO's proposal.

BC Hydro assessed the impacts of a winter disconnection moratorium and made the following conclusions.

1. A Disconnection Moratorium would need to be offered to all customers.

As noted, no Canadian jurisdictions offer winter disconnection moratoriums solely for low income customers. This approach has benefits in that it avoids the need to verify a customer's income. However, it also results in a substantial increase in the revenue-at-risk because of the much larger customer base affected. BCOAPO endorses cold weather protections for Residential customers irrespective of income.

2. A Disconnection Moratorium without acknowledging the climatic conditions of BC Hydro's service area would have negative financial implications.

As described in section 4.3, BC Hydro believes that use of its RDR capabilities as been a critical component in its ability to manage its Aged A/R and bad debts. As such, any restrictions on the disconnection of non-paying customers not applying for MSDSI support or entering into other forms of payment terms would jeopardize future collections performance, and thereby have detrimental effects on all customers.

BC Hydro has validated these concerns through discussions with peers at several Canadian utilities. In particular, the following impacts of a general moratorium on winter disconnections were noted:

- Customers do not take action to reduce their outstanding balances during the moratorium period. This causes Aged Receivables to increase;
- Customers do not fully pay new bills, which also increases receivables; and
- When the moratorium is lifted in the spring, many customers find they are unable to pay their balances and are subsequently disconnected.

Furthermore, feedback from Ontario utilities was that mandatory repayment terms further exacerbated these issues.

BCOAPO acknowledged the peer discussions upon which BC Hydro relies in its analysis but also notes that substantial empirical analysis has reported that cold weather shutoff protections do not result in a systematic nonpayment of bills, citing Iowa as an example. BC Hydro recognizes that impacts likely vary between utilities and regions but remains skeptical based on the anecdotal experiences of peer utilities.

3. British Columbia has different weather patterns than the remainder of the country.

As shown in Figures 7 and 8, B.C.'s weather conditions are different than those in the rest of the country, with the Lower Mainland and Vancouver Island rarely reaching freezing temperatures. Accordingly, the drivers and program conditions for a winter disconnection moratorium are very different depending on location. Any potential moratorium should reflect these differences.

Figure 7: Extreme Minimum Temperature Zones

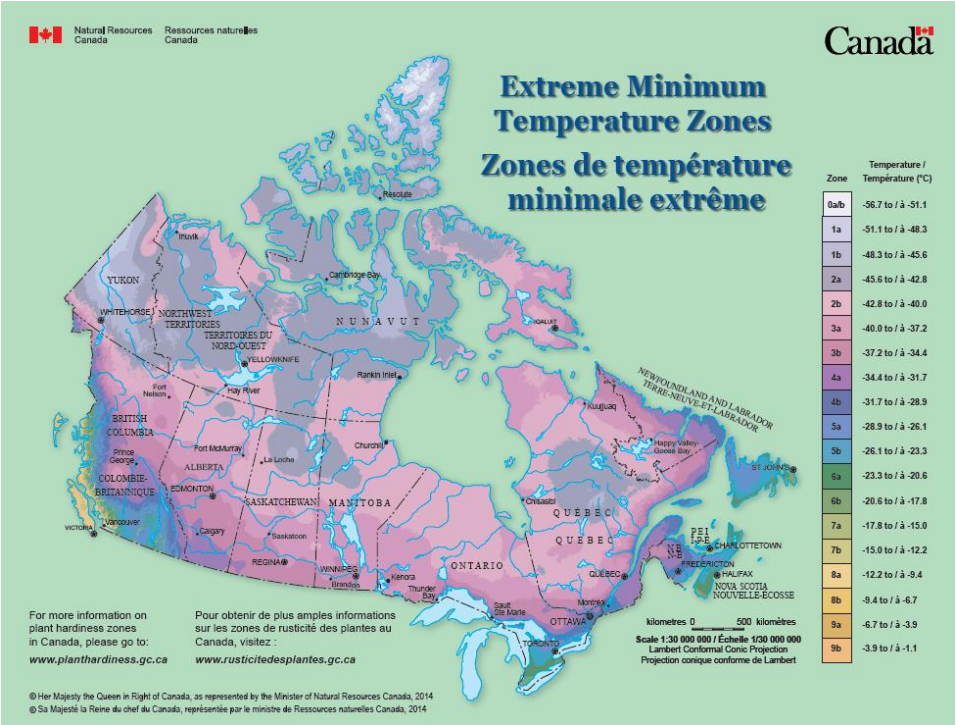


Figure 8: Energy Star Climate Zones

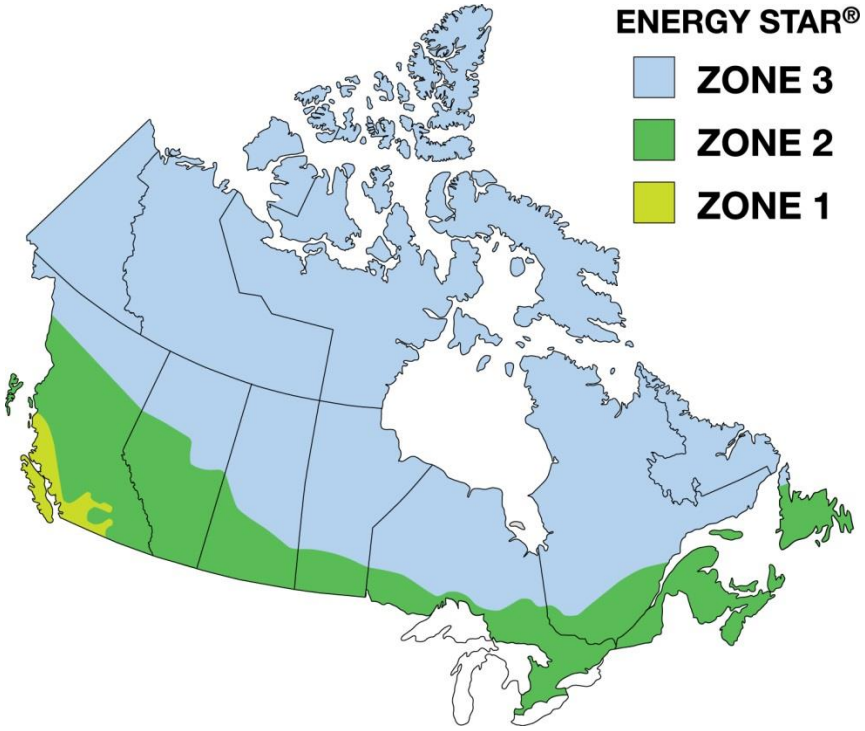
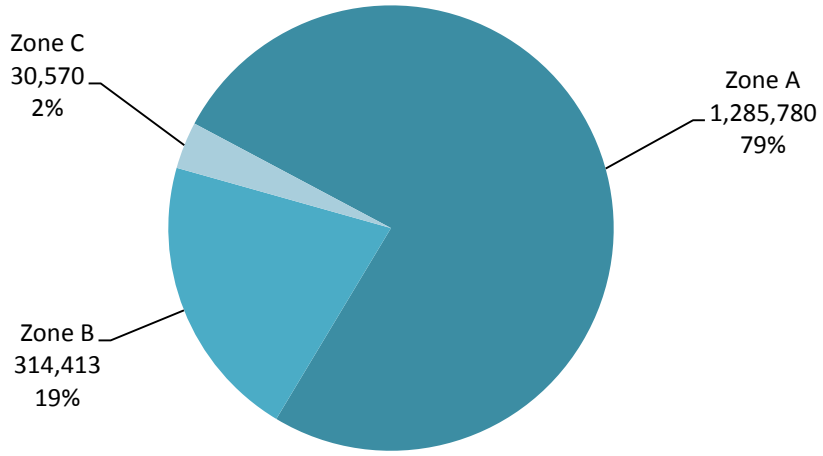


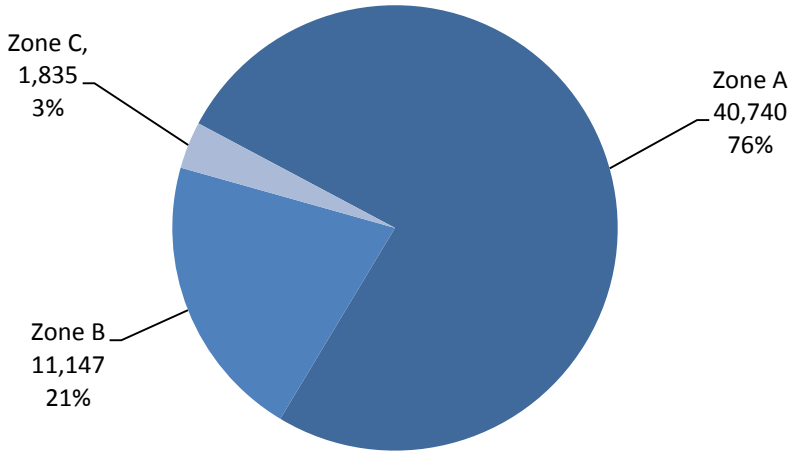
Figure 9 shows the approximate number of BC Hydro's residential customers for each of the climate zones identified in Figure 8.

Figure 9: Customers by Energy Star Zone



As shown in Figure 10, approximately 76 per cent of disconnections for non-payment from April 1, 2014 to December 10, 2015 were located in the warmer Zone A region (predominately Lower Mainland and Vancouver Island).

Figure 10: Disconnections by Energy Star Zone



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4. Flexibility would be gained through use of load limiting devices.

Load-limiting meters are in use by a number of Canadian utilities. They have been implemented to either limit the current supplied to the premises (e.g., 15 Amps for Manitoba Hydro) or as a timer that cycles supply on and off (e.g., 2.5 hours off / 0.5 hours on for Hydro Ottawa). Refer to Table 8.

Table 8: Canadian Electric Utilities Using Load Limiters During Winter Period

Utility	Description
Horizon Utilities (Ontario)	Load limiters are installed during winter months to homes that control heat.
Oakville Hydro (Ontario)	During the winter months when the temperature is below zero, utility will use a timer.
Oakville Hydro (Ontario)	In winter months use load limiters for residential customers (full disconnection two weeks after load limiter installed if no payment). The utility also allows its staff both administrative and field workers to use their judgment if they encounter a situation where additional time allowed is called for.
Hydro Ottawa	Winter moratorium of 1 December – 15 March. Customers who have a remote disconnect meter are placed on a schedule that will allow timed intervals of power of 2.5 hours off and 0.5 hours on. All other customers will have timers physically installed – with same timed intervals of power as remote meters. Disconnects are placed on hold for extreme temperatures and on a case by case basis for accounts that have been deemed sensitive in nature (i.e., illness, seniors, etc.).
SaskPower	Utility will not disconnect customers who rely on electric heat in the winter months. All other residential customers will be disconnected with a load limiter.
EPCOR	Load limiting devices are installed for residential services. All other services are fully disconnected.

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Utility	Description
Manitoba Hydro	2009 'Affordable Energy Program' summary, page 10 states that Manitoba Hydro installs load limiter which limits capacity of service to 15 amps, which Manitoba Hydro states allows enough energy for furnace fan to run, with natural gas service remaining connected throughout the 1 October to 14 May 'heating season'.

BC Hydro's smart meters have a service-limiting capability that automatically disconnects service if a defined threshold is reached. The technical specifications have been tested and the feasibility of the concept has been confirmed; however, before implementing this solution it would be necessary to conduct a more thorough review of development costs and the impacts on business processes.

BC Hydro confirmed through a review of product specifications and testing in its metering laboratory that the Itron single phase meters in use at most residential premises have functional Service Limiting capability. In the event that BC Hydro wished to invoke Service Limiting for a customer in arrears, BC Hydro could initiate the feature remotely. Once enabled, the meter disconnect switch would automatically open whenever the customer's connected load exceeds a thresholds (measured in Watts) for approximately 15 to 20 minutes. Depending on how BC Hydro chooses to implement the feature, the meter could be configured to automatically reconnect service after a pre-set time.

Based on this assessment it appears that introducing Service Limiting capability is feasible and could provide an option to continue to provide a minimal electricity supply for heating while not enabling an unencumbered supply of electricity to a customer that is in arrears. However, there remain a number of issues that need to be investigated before this could be implemented. In particular:

- How does the Watt threshold relate to a customer's load and what is the impact on an anticipated minimum level of heating?
- What IT changes are required to enable and support this feature, and how much would that cost?
- What are the business rules for determining when Service Limiting would be used, and for how long before proceeding with a full service disconnection?

Once these questions have been answered, BC Hydro would likely propose a trial project to evaluate customer behaviour and any detrimental impact on the disconnect switch before introducing it broadly.

BC Hydro Proposal

BC Hydro recognizes BCOAPO's concerns with respect to cold weather disconnections. However, it remains concerned that a general moratorium would restrict use of a highly effective collections tool for extended periods, and that in doing so other customers would incur higher costs in the form of delayed revenue and bad debts. As a result, BC Hydro does not support a general winter moratorium on disconnections. In view of practices in other jurisdictions as well as the recognition that some customers could experience greater hardship/impacts during the winter months as a result of being disconnected, BC Hydro will explore a winter disconnection policy through RDA Round 2 IRs and discussion with BCOAPO along the following lines:

Lower Mainland / Vancouver Island:

- BC Hydro would not disconnect Residential services for non-payment when the temperature is forecast to be below 0 degree Celsius in the 24-hour period immediately following the proposed disconnection.

Remainder of BC Hydro's service area:

- Where disconnection will affect the supply of heat to the occupied residential premises, BC Hydro would not fully disconnect Residential premises between 1 November and 31 March, or any other time when the temperature is forecast to be below 0 degree Celsius in the 24-hour period immediately following the proposed disconnection.

Considerations underpinning the proposals to be explored are:

- First, restrictions on winter disconnections should be regional. In general, customer impacts of disconnection will be greater in colder regions than in the Lower Mainland and Vancouver Island because longer periods of cold weather create a greater potential for damage such as freezing pipes. BC Hydro notes that it has different business rules for disconnections of vacant accounts in winter months in Lower Mainland/Vancouver Island than in areas with colder weather;

- Second, restrictions should be based primarily on temperature rather than on a date range, particularly in warmer regions.

A policy with such considerations would likely provide some balance between the need for customers outside the Lower Mainland and Vancouver Island to have a basic supply of electricity to keep their premises from freezing and BC Hydro's need to manage bad debts and avoid an increasing risk of unpaid balances.

BC Hydro intends to explore further costs associated with such a winter disconnection policy. Implementation of the winter disconnection policy would require upfront IT investment to adjust Dunning notifications and include temperature considerations within the credit analyzer (which filters and prioritizes accounts for final review by agents prior to issuing the disconnection order). The cost of these changes has not yet been estimated.

BC Hydro would also propose to retain the option of limiting service through either RDR-enabled smart meters or by installing a load limiter. This approach is consistent with Manitoba Hydro's approach, subject to the results of BC Hydro's investigation of the feasibility and cost-effectiveness of using smart meters to limit allowable load as part of a potential winter disconnection policy.

5.4.5 Late Payment Charge Waiver

BCOAPO is proposing a mandatory Late Payment Charge waiver for Eligible Low Income Customers that is consistent with OEB Low Income Customer Rules by granting a waiver of Late Payment Charge once a customer has entered into payment arrangements. BCOAPO has indicated this request is prospective only and does not extend to a waiver of Late Payment Charges incurred prior to payment arrangements being created.

<u>BC Hydro Assessment</u>

BC Hydro's current business practice meets the intent of the OEB Low Income Customer Rules. As noted in Table 1, currently the Late Payment Charge is waived for the period of time a residential customer is on an installment plan; as noted above under Table 1, item #2 (Flexible Arrears Payment Arrangements), BC Hydro's current installment plans are typically up to three months as compared to the OEB Low Income Customer Rules 8-16 months.

BC Hydro does apply the Late Payment Charge for a one-time payment deferral.

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BC Hydro Proposal

BC Hydro does not propose changes to its current business practices. BC Hydro is not aware of a Canadian electric utility that has adopted mandatory Late Payment Charge waiver for low oncome customers in all circumstances; the OEB Low Income Customer Rules confine the waiver to customers entering into payment arrangements.

5.4.6 Minimum Reconnection Charge Waiver

BCOAPO proposes to waive the Minimum Reconnection Charge when a low income customer is disconnected and reconnected.

BC Hydro Assessment

BC Hydro has the following observations regarding this proposal:

- BC Hydro will continue to incur costs of disconnecting customers for non-payment and subsequently reconnecting their service. Assuming approximately 30,000 disconnections each year, and using the 2014 REUS findings of 10 per cent of customers being low income, BC Hydro would under-recover a minimum of $90,000 in revenue annually. These costs would need to be recovered in general rates;

- The reduction in the Minimum Reconnection Charge, which has been set at $30 pending its review, means there is limited benefit to a low income customer;

- This waiver would require confirmation of income to determine eligibility. Unless eligibility was already established in conjunction with another low income initiative, the administrative costs would likely be disproportionate to the benefit;

- A mandatory of waiver of Minimum Reconnection Charges for Eligible Low Income Customers requires amendment to section 11.2 of the Electric Tariff.

BC Hydro Proposal

BC Hydro does not support a retroactive waiver of the Minimum Reconnection Charge because it would result in an under-recovery of collection costs incurred and so would need to be absorbed into general rates. Also, there isn't a scenario where not assessing the Minimum Reconnection Charge for a low income customer is cost-effective in the sense of actually saving money for the other customers.

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5.5 Discussion of Other BCOAPO Suggestions

As noted in section 2.2, in addition to its proposal that BC Hydro adopt the OEB Low Income Rules, BCOAPO also provided a number of suggestions on business practices that would not require changes to terms and conditions but would, in BCOAPO's view, increase the level of customer experience or contribute to an increase in cost effectiveness of collections actions. These are discussed below.

5.5.1 Low Income Customer Services Unit

BCOAPO proposed the creation of a specialized customer service unit to provide additional support to low income customers. BCOAPO has provided a contact name at an Eastern U.S. utility that can provide BC Hydro more information on the scope of such a program, such that it has sufficient information to address BCOAPO's proposal.

BC Hydro notes that if a customer calling its Interactive Voice Response (**IVR**) phone system has an overdue balance, he or she is automatically directed to a team of agents trained to establish payment arrangements. This is the same team that discusses the status of MSDSI client or applicant files, as described in section 4.2 above. The team will often refer customers to social assistance agencies. They also recommend DSM programs that the customer can access so as to decrease their electricity consumption and bills. BCOAPO stated to BC Hydro that referrals to social assistance agencies is another reason for having a low income specialized customer service unit, as this unit could maintain up to date information about social assistance programs and agencies.

This notwithstanding, BC Hydro acknowledges that the primary purpose of the team is to secure payment arrangements for the customer's outstanding balance and that it does not meet the full intention of the BCOAPO's proposal. BC Hydro will consider providing additional training for the team to increase the level of support it can provide for low income customers; however, BC Hydro also notes that the team will require additional resources to offset the longer handling time per call.

5.5.2 Winter Disconnection Survey

BCOAPO proposed creation of a winter disconnection survey to assess on an annual basis the number of residential customers who have been disconnected for nonpayment who will enter a heating season without service reconnected.

While BC Hydro supports the idea of a disconnection survey, agreeing to such a survey at this time is premature pending continued discussion with BCOAPO concerning BC Hydro's winter disconnection policy. As noted in section 5.3, over half of disconnected accounts are reconnected the same day, and over 90 per cent within 21 days. Moreover, BC Hydro has accurate records as to the status of its accounts. Accordingly, given that surveys take financial and labour resources to undertake, BC Hydro is uncertain that sufficient value would be obtained to justify the costs. BC Hydro would be willing to reconsider its position if BCOAPO can more clearly identify the purpose and intended uses of this information.

BCOAPO stated to BC Hydro that the primary purpose of the survey would be to identify and track dangers associated with customers who are disconnected during a non-heating season and are entering a heating season without electricity service. BCOAPO maintains that this would assist BC Hydro to identify customers that could be using dangerous heating systems such as portable propane systems and ovens to heat their homes. Finally BCOAPO stated that another purpose would be to track housing units that have been abandoned.

5.5.3 Low Income Advisory Group

BCOAPO proposed the creation of a standing BC Hydro Low Income Advisory Group, which could include (among others) representatives from BCPIAC, MSDSI and several client organizations of BCPIAC. The Advisory Group would be not be convened until after the RDA Phase 1 decision from the Commission.

BC Hydro is supportive of this proposal because it would build upon the relationships recently developed with BCPIAC and MSDSI, allow all parties to better understand the challenges faced by low income customers as they navigate BC Hydro's and MSDSI's processes, and identify opportunities that support BC Hydro's corporate priorities of making it easy for customers to do business with us, exploring the full potential of energy conservation, and continuing to improve the way we operate.

BC Hydro notes that it has recently created an internal working group to improve the linkages between low income energy conservation programs and collections processes. It also notes that a Low Income Advisory Group existed previously but was primarily focused on helping low income households manage their energy costs through awareness and participation in energy conservation activities.

Before convening the Advisory Group, BC Hydro would want to ensure that the group's Terms of Reference are aligned with its priorities, and would also need to identify the resource and

funding requirements. MSDSI indicated it supports the concept of an Advisory Group and will participate in discussions regarding Terms of Reference. BCOAPO notes that Terms of Reference for the Advisory Group are essentially captured by the second paragraph above (in section 5.5.3). In BCOAPO's view, the Terms of Reference should not be overly restrictive, as they should encourage conversation among participants. BCPIAC is willing to participate in such a group at no charge to BC Hydro ratepayers, just as BCPIAC participates in BC Hydro's Electricity Conservation and Efficiency Advisory Committee at no charge. BCOAPO proposes that the Advisory Group meet three or four times a year for about two hours.

5.5.4 Periodic Reporting

BCOAPO recommended periodic reporting of specified credit and collection-related data based on data recommended in the United States by NASUCA. Appendix A shows NASUCA's recommended list of reporting elements.

BC Hydro is not opposed to providing periodic reporting because most of the reporting elements are available through existing operating reports. However, it makes the following observations:

1. The audience and purpose of this information should be clarified;

2. As BC Hydro cannot currently identify which customers are considered low income, it is unclear of the value periodic reporting would offer beyond general awareness of collections activities. BCOAPO noted that BC Hydro can identify about 2/3 of its low income customer population, as up to two thirds of its LICO and under customers receive assistance from MSDSI;

3. Many of the data elements have previously been requested through other avenues such as *FOIPPA* requests by BCPIAC or other individuals. BC Hydro would be supportive of periodic reporting if it would reduce the number of these ad hoc requests for information. BCPIAC confirms that periodic reporting would reduce such requests from BCPIAC; and

4. Reporting would need to be at a reasonable frequency (e.g., annually). BCOAPO communicated to BC Hydro that it agrees with annual reporting, but on a monthly data basis, so that trends and changes in trends can be identified.

BC Hydro suggests that BCOAPO's proposal for periodic reporting be reviewed in conjunction with the creation of Terms of Reference for a Low Income Advisory Group. This would provide a forum to discuss what information is considered necessary by the advisory group members, and at what frequency, and also allow BC Hydro to assess the level of difficulty in providing this reporting. MSDSI indicated it is supportive of enabling greater sharing of information for the purpose of reporting and analysis, subject to addressing *FOIPPA* concerns.

5.5.5 Additional Collections Metrics

BCOAPO recommended that BC Hydro use the following indicators to provide additional information when assessing the cost effectiveness of its collections processes:

- Complete Bill Payment: The most common indicator of whether complete payment has been received from a utility customer involves measuring both the incidence and depth of arrears. The incidence of arrears considers the proportion of the total population in arrears. The depth of arrears considers the size of arrears at any given point in time. A bill coverage ratio (the proportion of current bills paid) should also be used (on a monthly, seasonal and annual basis) to consider complete bill payment over a period of time;

- Prompt Bill Payment: Prompt bill payment considers the timeliness of bill payment, not merely whether a customer pays his or her utility bill in full. If a utility renders a bill for $100, that company wants a customer to pay the bill by the due date as well as paying the bill in full. Bill promptness is primarily measured through one of two metrics: (1) by the use of a "weighted arrears" statistic called "bills behind"; and (2) the use of the more commonly recognized, but less complete, aging of arrears;

- Regular Bill Payment: The regularity of bill payment measures the extent to which customers make at least some bill payment each month. A customer may maintain a relatively low level of arrears by paying multiple months of bills on an infrequent basis. An examination of January arrears, for example, does not distinguish between the customer that has made his or her last twelve monthly payments on time and in full, the customer that has made $0 in payments during August through October (perhaps waiting for a public assistance grant to pay those arrears), and the customer who makes three payments over the year of amounts equal to the total annual bill. The regularity of bill payment measures the extent to which some payment is made in response to each bill rendered;

- Unsolicited Bill Payment: The extent to which bill payments are "solicited" considers the extent to which, if at all, a company is required to engage in collection activities to generate

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a bill payment. An unsolicited bill payment involves a payment that is made in response to a bill without any need for company collection contact with the customer. Measuring collection activities considers both the number and the intensity of collection activities. A more intense collection activity involves a more direct company-to-customer contact than does a less intense activity. Issuing a posted disconnect notice involves a more intense activity than issuing a computer generated "reminder" notice. The disconnection of service involves a more intense collection activity than does a call center contact.

BC Hydro acknowledges that its collections metrics focus primarily on revenue collection and arrears management, and do not provide insight into the payment behaviours of its customers. Furthermore, there is limited ability to segment customers so that specific impacts can be identified or programs developed. BC Hydro notes that the data structure of its billing system makes it difficult to match customer payments with the originating invoices in a meaningful way. However, it agrees to review these recommended metrics to determine which can be practically implemented.

5.5.6 Designation of a Third Party to Receive Collection Notices

BCOAPO requested that BC Hydro adopt an internal business practice of allowing customers to designate a third party to receive collections notices at the same time the customer receives such notices.

BC Hydro notes that this functionality is already available for customers having on-line MyHydro accounts. Customers are able to provide View access to other users with MyHydro profiles (who do not necessarily need to be BC Hydro customers). The other users then have access to review account details and invoices, and are also emailed copies of any Dunning notices sent.

BC Hydro has been promoting this feature when working with First Nations groups. For example, a housing administrator can use this tool to monitor the account standing of a community elder. BC Hydro would support the idea being promoted with additional groups, with the caveat that investment in web enhancements may be necessary to support the needs of organizations that would monitor the account status of a large number of individuals (i.e., because receiving large volumes of email for bill notifications and Dunning notices would not be efficient).

This feature is not practical for customers without a MyHydro profile. Additional IT development would be required to enable duplicate notifications by mail. As well, BC Hydro would incur additional paper, printing and postage costs to support this method of delivery.

5.5.7 Medical Emergencies

BCOAPO requested that BC Hydro create a business practice allowing for a delay in the disconnection of service when a customer can certify that the customer, or a permanent resident of the customer's household, has a medical emergency that would be caused by or exacerbated by the disconnection of service.

BC Hydro does not have formal criteria for delaying disconnection of a customer with a medical situation. Instead, the collections agent or work leader is given the authority to postpone a disconnection when he or she believes a customer's concerns are legitimate and that disconnection could cause harm. The positive aspect of this informal process is that it allows customers with legitimate concerns to be granted an extension without the need to obtain a medical certificate. However, there is also a downside in that some potentially eligible customers may be disconnected if the agent does not believe the customer is truthful or does not understand the nature of the impact.

BC Hydro proposes to maintain its existing process but would add a disconnection grace period of five business days to allow the customer time to provide a medical certificate or other appropriate documentation. This would be similar to the grace period being offered to customers applying for MSDSI assistance, though with a shorter period to reflect that an application and adjudication process is not necessary. BCOAPO proposes a disconnection grace period of 21 days, as five days may be too short a timeframe for customers to get medical documentation. There is often a wait time to see a general practice physician. Once the customer has provided the medical certificate (or other appropriate documentation) to BC Hydro, BCOAPO proposes that the customer would be required to provide updated medical documentation every 30, 60, or 90 days to extend the grace period.

BC Hydro opposes a request for it to maintain an inventory of customers with critical medical equipment. Such a system would be difficult to keep up-to-date as customers' medical situations change, and so would require significant effort without assurances of accuracy. BC Hydro also notes that it cannot guarantee continuous supply of electricity – storms, motor vehicle accidents and other factors can cause unplanned outages, and planned outage are sometimes necessary to safely undertake maintenance and system enhancements. Notwithstanding the recognized affordability issue for low income customers, households that

rely upon electricity for critical medical devices should take additional steps to ensure their needs are met in the event of an outage.

5.5.8 Application of Unclaimed Security Deposits to a Crisis Intervention Fund

BCOAPO's recommendations for security deposit reform extend not merely to the decision of whether to impose/refund a deposit, but extend to the use of deposits that remain unclaimed subsequent to a final bill. BCOAPO urges that when posting a deposit, a customer be allowed to assign an unclaimed deposit, if any, to a crisis intervention fund. This proposal is based on the proposition that in so doing, even if unclaimed, the deposit will thus be put to the use for which it was posted in the first instance (a reduction in bad debt).

Current process is to automatically apply unclaimed credits on closed accounts to BC Hydro's provision for bad debts after 180 days. The credit is 'value adjusted' similarly to debit amounts such that the credit is gradually decreased (and applied as an offset to bad debt expense) over a period of six years. However, the full value of the credit is provided to the customer if he or she requests it at any time within the six year period.

More consideration would be required before moving forward with this proposal. In particular, it is premature to make a determination if BCOAPO intends to advocate for an emergency bill assistance program. Additional issues to consider would include the following:

- Such a program would require management of an external agency to review applications and make grants;
- Credits are currently applied against bad debts generally. As a result, this would result in a transfer from other customers in the form of higher bad debt expense; and
- BC Hydro would need to consider how to address credits that are ultimately returned to customers but may have already been redirected to the crisis fund.

5.6 Summary

BC Hydro acknowledges and appreciates the collaborative approach that BCOAPO has used in establishing its proposal for low income terms and conditions. BCOAPO provided a number of useful insights and perspectives that help BC Hydro understand the issues faced by low income customers; these insights will only serve to help BC Hydro improve its policies and processes to achieve a key corporate priority of making BC Hydro easier to do business with.

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Item #1 – Mandatory Waiver of Security Deposits for Eligible Low Income Customers

BC Hydro does not support a broad, mandatory waiver of security deposits for all Eligible Low Income Customers, on the basis of financial risks and administrative costs to determine eligibility. However, such a waiver would be appropriate when BC Hydro's risk is mitigated through receipt of direct electricity payments from MSDSI or other forms of guarantees:

- Security deposits will be waived for low income customers whose payments are being made by MSDSI (e.g., Direct, about 6,000 customers);
- BC Hydro is exploring the waiving of security deposits for MSDSI Indirect clients (about 124,000 of BC Hydro's low income customers).

Item #2 – Flexible Arrears Payment Arrangements

With some minor procedural changes as noted, BC Hydro will also meet the intent of Flexible Arrears Payment Arrangements.

Item #3 – Disconnection Grace Period

BC Hydro is of the view that it already meets the intent of the OEB Low Income Rules with respect to Disconnection Grace Period.

Item #4 – Winter Disconnection Moratorium

BC Hydro is exploring a winter disconnection policy that aligns with the Canadian jurisdictions referenced in Table 1 above, adjusted for the climactic conditions of BC Hydro's service area. Any winter disconnection policy should be regionalized to reflect the difference in weather conditions in the Lower Mainland and Vancouver Island as compared to the rest of the country. BC Hydro also endorses the ability to install service or load limiting devices as an alternative to full service disconnection.

Item #5 – Mandatory Late Payment Charge Waiver for Eligible Low Income Customers

BC Hydro is of the view that it already meets the intent of the OEB Low Income Rules with respect to the Late Payment Charge waiver. BC Hydro does not support a broadly-based Late Payment Charge waiver for Eligible Low Income Customers that goes beyond the OEB Low Income Rules.

Item #6 – Mandatory Minimum Reconnection Charge Waiver for Eligible Low Income Customers

BC Hydro does not support a mandatory waiver of the Minimum Reconnection Charge for Eligible Low Income Customers, on the basis of under-recovery of costs and lack of sufficient customer benefit to demonstrate this would be a cost-effective change.

Other BCOAPO Suggestions

With respect to BCOAPO's other suggestions described in section 5.5, BC Hydro agrees in principle with proposals that will lead to its continued building of relationships with MSDSI and low income advocacy groups, as well as to the development of more targeted reporting and performance metrics that support the continual improvement of its collections processes and customer experience.

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Appendix A:
NASUCA Recommended Data Reporting Elements

(1) number of residential customers who were required to pay a deposit to demonstrate creditworthiness to initiate gas or electric service and the average amount of the deposit;
(2) number of residential customers who used alternative methods to a deposit to demonstrate financial responsibility while initiating service;
(3) number of residential customers who were required to pay a deposit to initiate gas or electric service but were unable to do so;
(4) number of customers enrolled in each specific and distinct low-income payment plan;
(5) average payment amount for customers in each specific and distinct low-income payment plan;
(6) number of customers enrolled in every other type of payment plans offered by the utility to other (non-low-income) customers;
(7) the aggregate dollar amount that is being deferred in each specific and distinct type of low-income or other payment plan;
(8) the aggregate dollar amount that has been collected in each specific and distinct type of low-income and other payment plan;
(9) number of customers who defaulted on each specific and distinct type of payment plan;
(10) provide the dollar value and number of residential accounts (and low-income accounts) written off as gross uncollectibles, in that the accounts have been written off and sent to a collection agency;
(11) the dollar value and number of residential accounts (and low-income accounts) written off as net uncollectibles, in that the accounts have been written off after a collection agency has failed to collect payment;
(12) separately provide the total number of accounts in arrears between 30 – 60 days, 60 – 90 days, more than 90 days;
(13) separately provide the total dollar amount of the arrears that were owed between 30 – 60 days, 60 -90 days, more than 90 days;
(14) number of residential customers receiving a disconnection notice;
(15) number of low-income customers receiving a disconnection notice;
(16) number of residential customers disconnected for non-payment;
(17) number of low-income customers disconnected for nonpayment;
(18) number of customers enrolled in a low-income payment assistance program when they were disconnected for non-payment;
(19) number of residential customers who used special medical certification procedures to avoid disconnection;
(20) separately provide the number of residential disconnections, and low-income residential disconnections, where service was reconnected within ten business days, ten to thirty days, thirty to sixty days, sixty to ninety days, and greater than ninety days.

193.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.193.1 Please provide a copy of all reports, evaluations, memos, analyses or other written documents of any nature containing BC Hydro methodology, procedure or process designed to systematically review, study or assess BC Hydro residential billing and/or payment records in an effort to:

(a) Characterize patterns of nonpayment;
(b) Identify the characteristics of nonpayers;
(c) Identify predictors of nonpayment;
(d) Identify strategies to reduce nonpayment;
(e) Identify early indicators of nonpayment.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.198.2.

194.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.194.1 Disaggregated by heating and non-heating customers, please provide the number of residential accounts by month for each month January 2012 to present.

RESPONSE:

Please refer to Attachment 1 to this IR response.

195.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.195.1 Please identify all BC Hydro accounts that include expenses for the following residential collection activities:

(a) Late payment notices;
(b) Notices of disconnection for nonpayment.
(c) Disconnections for nonpayment.
(d) Field collections not involving disconnection for nonpayment.

Separate these expenses by sub-accounts if available.

RESPONSE:

As further described in BC Hydro's response to BCOAPO IR 1.183.1, the expenses for items (a), (b) and (d) are contained within the Customer Service Operations department. Both Customer Service Operations and Field & Grid Operations incur costs for item (c).

There are not specific accounts for the items described above. The costs of these activities are planned and recorded within Cost Centres and Cost Elements that in all cases include costs unrelated to these activities. BC Hydro uses Internal Orders to provide further breakdown of plan and actuals.

(a) and (b) are included in Cost Element 635050 – Contract Services of Cost Centre 19452.

The plan costs for these costs are included within the "TPC" tab in Attachments 1 to 3 of BC Hydro's response to BCOAPO IR 1.183.1, as one of the items planned within "Bill Customer/Mass Market Billing". Because BC Hydro uses the same vendors, the plan is developed and costs recorded as a line item for all customer correspondence, which includes paper bills, Dunning notifications, and other billing-related correspondence (e.g., notification of failed pre-authorized payments). Actual costs are then allocated based on volumes. Some of these costs are further planned and recorded under Internal Order 80015578.

A portion of costs related to (c) contained within Cost Element 635250 – ABS Meter Reading of Cost Centre 19670.

As noted in Attachment 1 to BC Hydro's response to BCUC IR 1.124.1, Field Metering Analysts perform 41 per cent of manual disconnections and 32 per cent of manual reconnections as part of ABSBC's contract for provision of Field Customer Services. Disconnection and reconnection activities are not planned or recorded as separate cost elements.

The remainder of costs related to (c) are also performed by PLTs or Meter Technicians in the Field & Grid Operations department. Again, these costs are not planned or recorded as costs specifically for disconnections or reconnections.

With respect to (d), BC Hydro does not do field collections and so there are no accounts related to this activity.

196.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.196.1 For Fiscal Years 2013 to present, please provide period-end totals of collection expenses booked to each account and sub-account identified in the Information Request immediately above.

RESPONSE:

The actual costs recorded in the Internal Order noted in BC Hydro's response to BCOAPO IR 1.195.1 are as follows:

Activity	Cost Centre	Internal Order	F2013 ($000)	F2014 ($000)	F2015 ($000)
Dunning Notifications	**19452**	**80015578**	**692**	**765**	**840**

197.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.197.1 For Fiscal Years 2013 to present, please provide a copy of all BC Hydro budget documents specifically identifying collection activities as a separately stated line-item.

(a) Provide those budget documents indicating the budgeted expenditures year-to-date;
(b) Provide those budget documents, if different, of actual expenditures year-to-date.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.183.1.

198.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.198.1 Please provide a copy of all written documents that explain, assess or otherwise discuss the criteria BC Hydro uses to assess on an ongoing basis the effectiveness of its current credit and collection activities.

RESPONSE:

A consolidated document does not exist that discusses the criteria used to assess the effectiveness of credit and collection activities. However, BC Hydro uses a number of metrics to assess its ongoing performance. These metrics are reported on monthly. Metrics include:

- **Days Sales Outstanding;**
- **Aged Accounts Receivables (accounts, dollars, per cent of revenue):**
  - **30-day "buckets" to 180 days;**
  - **Residential versus non residential;**
  - **Active accounts versus closed accounts;**
- **Payment arrangements made (accounts and dollars);**
- **Payment arrangement success;**
- **Net bad debt (accounts, dollars, per cent of revenue);**
- **Number of credit actions (i.e., Dunning statistics);**
- **Security deposits:**
  - **General Ledger balances;**
  - **Number assessed and returned;**
- **Accounts referred to collection agencies;**
- **Collection Agency performance;**

- **Overdue closed accounts;**
- **Operator reviews completed;**
- **Disconnection orders approved and completed; and**
- **Bankruptcies.**

The key metrics used to determine overall performance of credit and collection practices are day's sales outstanding, bad debt expense, and accounts receivables aged 60 days or more. These are trended seasonally and year over year.

198.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.198.2 Separately provide any written assessment, evaluation, report or other written document of any nature prepared since January 1, 2010 which discusses the effectiveness of BC Hydro's current credit and collection activities.

RESPONSE:

Please refer to the attachments to this response:

Attachment 1 – Analysis of bad debts and Aged A/R;

Attachment 2 – A summary of opportunities and recommendations related to security deposit processes; and

Attachment 3 – An overview of bad debt accounting and collections practices.

BC Hydro
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EXECUTIVE SUMMARY

PROPOSED SECURITY DEPOSIT POLICY REVISION – OCTOBER 2015

PURPOSE: To recommend changes to security deposit policies to mitigate bad debt while also improving customer experience.

Background

BC Hydro uses security deposits to reduce the risk of non-collection from new customers with poor or unknown credit history, as well as from existing customers with poor payment histories. As defined in the Electric Tariff, the security deposit is equal to 2 or 3 times the customer's average monthly bill depending on billing frequency. Security deposits are returned to customers after 12 months of good payment history. Interest is paid on security deposits at BC Hydro's weighted average cost of debt (currently 4.14%).

Analysis of residential closed accounts, bad debts and security deposits revealed that our current security deposit practice is ineffective. In short, we discovered that:

1. We don't ask for security deposits from the right customers;
2. We don't hold security deposits long enough;
3. We don't ask for enough security deposits from high-consuming residential accounts;
4. Security deposit requirements are not clear to customers, and
5. In some cases, the application of security deposits can increase rather than decrease financial risks.

This memo provides the rationale for these conclusions and recommends changes to business practices that will reduce risk of non-collection while also improving customer experience.

Analysis

Closed accounts with outstanding balances were analyzed to determine the effectiveness of current security deposit processes. Looking at four years of data:

- only 13% of new accounts had initially been assessed security deposits;
- 97% of the security deposits collected from both new and deteriorating accounts were subsequently reversed or returned to customers before the accounts were closed, and
- 83% of closed accounts with aged outstanding balances had never been accessed a security deposit.

The analysis concluded that current security deposit processes were not effective in targeting accounts that ultimately would end up as bad debt.

Accounts that ended up in the 2014 residential bad debt were then segmented in a number of ways such as housing type and the size of average monthly bill.

Apartments	Non-Apartments with average monthly bills under $500	Non-Apartments with average monthly bills greater than $500
27% of total accounts	73% of total accounts	0.5% of total accounts
54% of accounts in bad debt	45% of accounts in bad debt	1% of accounts in bad debt
23% of bad debt expense	59% of bad debt expense	18% of bad debt expense

EXECUTIVE SUMMARY

As shown, apartments comprise a disproportionate number of accounts that were written off as bad debt (although smaller bills made the actual write-off less). Also, there are a small number of high consumption residential accounts that have very high bad debts.

Apartments

- New accounts with estimated monthly bills under $55, mostly apartments, are currently not assessed security deposits to avoid administration and interest costs.
- Even when we hold a security deposit from them, it is usually returned before they receive their final bill
  - The analysis found the average account length was 14 months but we return the security deposit after 12 months.
- Security deposits are rarely assessed later for deteriorated credit, which implies bad debts are predominately from unpaid final balances rather than disconnections from non-payment.

High Consumption Accounts

- High consumption customers are either not assessed a security deposit in the first place or the security deposit assessed was based on a normal consumption estimate, which is not enough to secure their final bill balance.
- Many of these accounts are believed to be marijuana grow operations that pay their electricity bills until they intend to vacate the property.
- The Electric Tariff does not permit a security deposit to be raised on the basis of high consumption; as long as the customer pays their bill, BC Hydro cannot request further security on the account.

General Issues

- Although new customers are asked for identification (e.g., a driver's license number), the ID is not validated.
  - Customers with poor credit history can set up new accounts under different or fake names.
  - Lack of confirmed identify makes it significantly more difficult to recover losses from customers with electricity theft.
- The Tariff specifies the security deposit amount to be exactly two times (monthly billing) or three times (bi-monthly billing) of the estimated average monthly bill. The inflexible security deposit is seen to be punitive to low income customers.
  - In some cases, customers can successfully make payment arrangements on their outstanding balance but the security deposit becomes the tipping point at which they can't afford their bill, and so walk away entirely.

Proposal

The following are proposed changes to security deposit practices. They are intended to reduce financial risks but in most cases also provide an opportunity to improve customer experience by improving understanding and adjusting the level of security to the situation.

1. Change the Electric Tariff to add flexibility to the amounts and conditions for assessment of a security deposit:
   - Allow a security deposit of "up to" two times or three times the Customer's estimated average monthly bill, and
   - Allow a security deposit to be assessed or increased on the basis of a significant increase in consumption.

EXECUTIVE SUMMARY

- These changes were discussed with stakeholders during the 2015 RDA process and were generally supported. If addressed through an expedited approval process they will tentatively come into effect in April 2016.

2. Change the security deposit amounts assessed to new accounts without established credit:
   - Apply a fixed $50 security deposit for small accounts.
     - Addresses the lack of security currently obtained for apartments.
     - Standardizes the amount assessed, which improves customer understanding.
     - Average monthly bill for this segment is $29, so a $50 security deposit would provide a significant level of security against an un-paid final balance.
   - Apply a security deposit equal to one-time the average monthly bill for larger accounts, when the concern is lack of credit information rather than evidence of poor credit.
     - Makes it easier for new customers to do business with us by reducing the amount assessed where a specific risk of non-collection has not been identified.
   - Changes require approval of the proposed Terms & Conditions in the RDA.

3. Validate identification during the move-in process:
   - Utilize ID Verification software provided by Equifax to validate the identification provided by new customers.
     - Equifax already provides credit rating information so this is mostly an extension of an existing service.
   - Customers with identification believed to be fake or stolen will be unable to set up new accounts.
   - Reduces the risk of name switching, and improves the ability to assign prior bad debts to customers again creating accounts.
   - ID Validation will result in increased Equifax charges of up to $300k annually, as well as an increase in the CSR's handling time for new accounts. However, these costs are expected to be offset by improved effectiveness of collections and recoveries processes.
     - The increased Equifax charges have been included in the F17 budget submission because there will be a lag between when ID Validation costs are incurred and when bad debts are avoided.
     - The updated Account Charge proposed in the 2015 RDA remains the same at $12.40 per transaction, as the increased ID Validation cost was offset by savings from lower-cost online moving transactions.
     - MyHydro changes will also be required – these will be addressed through sustainment activities &/or the Evolve Customer Strategy workplan.

4. Increase the duration that security deposits are held:
   - Change the default to 24 months before a security deposit is returned to better align with the typical length of a rental agreement
   - No tariff changes are required – we 'may' return the security deposit after 12 months but are not obligated to.
   - If a customer requests the security deposit be returned after the minimum 12 months of on-time payments we would review the account and make a determination at that time.

EXECUTIVE SUMMARY

5. Assess or increase security deposits for at-risk high consumption accounts with good payment history:
   - Develop a process with Revenue Assurance to flag accounts that have a significant change in consumption.
   - Assess/increase a security deposit to the maximum possible on the basis of actual consumption.
   - Changes require approval of the proposed Terms & Conditions in the RDA.

6. Implement a graduated security deposit for deteriorated payment history:
   - For customers that previously have a good payment history, change dunning procedures to first assess a security deposit equal to an average one month bill.
   - This is considered low financial risk because analysis indicates most customers that are disconnected for non-payment are ultimately able to pay their balances.
   - Reducing the amount of the security deposit reduces the financial burden to low income customers that already have problems paying their bills.
   - Continued non-payment would result in a further increase in the security deposit to the full amount possible.
   - Changes require approval of the proposed Terms & Conditions in the RDA.
   - This change would be implemented in conjunction with a general review of dunning processes, including notifications, to maximize effectiveness while also managing costs.

Risks

1. Potential for rejection of proposed RDA changes, which is necessary to implement most changes:
   - Mitigated through stakeholder engagement process including support from low income advocacy groups.
2. Public scrutiny from new application of security deposits for small accounts:
   - Largely mitigated through $50 flat fee and reduced security deposits for other segments.
3. Public and regulatory scrutiny for holding security deposits longer than 12 months:
   - Mitigated by allowance under the tariff and implementation of a “review on request” process.
4. Increased revenue at risk by implementing a graduated security deposit process such that new accounts and ‘first offence’ accounts would be assessed only a security deposit of one-times an average monthly bill:
   - Mitigated by finding that security deposits on new accounts were ineffective.
5. Accenture and Equifax cost increases for ID Validation:
   - Mitigated through down-stream savings in unrecoverable revenues.
6. Implementation delayed because of IT priorities:
   - Mitigated by having changes planned and implemented through Customer Strategy PMO.
   - Equifax tool can be implemented for agents without much effort, as it is a stand-alone application.
   - Integration into MyHydro for online moves can be delayed by either stopping the setup of new Business Partners online (i.e., directing these to an agent) or accepting the risk that online applications will not have ID Validation.
7. Solution is not FOICO compliant:
   - Mitigated because Equifax is an existing tool, the CSR sees only a ‘pass’ or ‘fail’ response rather than the underlying credit information, and credit details are not retained.

Overview of Bad Debt from Customer Billed Sales

Prepared by: Tom Martin
Date: October 30, 2014

Table of Contents

Introduction 1

Overview of Bad Debt 1
- Generic Description of Bad Debt 1
- BC Hydro Accounting for Bad Debt 1
- Terminology and General Ledger (G/L) Accounts 2

Bad Debt for Residential and General Service Customers 3
- Credit and Collections Process Overview 3
  - Dunning Process 4
  - Collection Agency Process 6
- Provision Estimate 7
- Forecasting Bad Debt Expense as a Percentage of Sales 7
- Accounting Entries 8

Bad Debt for Large Industrial & Transmission Customers 10
- Process Overview & Provision Estimate 10
- Accounting Entries 10

Factors Influencing Bad Debt 11

Current Activities 11

Appendix A: Historical Bad Debt 13
- Residential and General Service: 13
- Industrial and Transmission: 14

Appendix B: General Ledger Account Information 15
- G/L 145900 Provision For Bad and Doubtful Accounts 15
- G/L 145920 Bad & Doubtful Accounts 16
- G/L 145052- Acc Rec – Adj Acct 17
- G/L 145000 – Electric AR 17

Introduction

Extending credit to customers results in bad debt when, over time, some of those customers do not pay their bills. This document provides an end-to-end overview of how bad debt is realized and accounted for at BC Hydro, as of F2015.

Overview of Bad Debt

Generic Description of Bad Debt

When a company sells a product or service and bills afterwards, it is extending credit to the customer and expects the customer to pay the bill in a timely manner. Knowing that not all bills will be paid (or paid in full), the company must fairly report this in its financial results, according to GAAP, by incurring an expense that reduces the expected Accounts Receivable (A/R). This expense is typically estimated as a % of revenue, and is a normal cost of doing business on credit.

This accounting entry hits the income statement as an expense, typically called Bad Debt Expense, and is offset by a reduction in A/R on the balance sheet, in a 'contra' (opposite) A/R account that can be called Bad Debt Provision (or Allowance for Doubtful Accounts, or other similar name). This amount is recorded at the same time the revenue is recognized, in order to match revenues and costs in the same period.

When it is known that a specific bad debt event has occurred (i.e. the customer is certain not to pay), then the amount is entered only on the balance sheet, as a reduction to that customer's A/R and the Bad Debt Provision account. Over time, the balance in the Bad Debt Provision grows and needs to be validated based on actual bad debt history. The result of this analysis may require an adjusting entry to the provision which would impact the bad debt expense.

BC Hydro Accounting for Bad Debt

BC Hydro follows this general method, except that it does not set up the provision (by recording an expense) when the revenue is recognized; rather, it sets it up based on estimates of collectability of accounts receivable. Since all billed sales are set up as Accounts Receivable, this is an equivalent method.

In addition, BC Hydro treats bad debt differently for large industrial transmission customers. This is a smaller number of customers that has higher credit risk. BC Hydro's Treasury department analyzes credit risk for these customers and determines if the provision is sufficient on an ongoing basis.

Terminology and General Ledger (G/L) Accounts

The following terminology is used in this document.

Bad Debt: This refers to the event of customer non-payment of a debt owed to BC Hydro.

Bad Debt Expense: This refers to the bad debt cost on the income statement.

- 666070 Prov/Uncol Bill-Expense

Bad Debt Provision: This refers to the contra account for Accounts Receivable on the balance sheet. BC Hydro uses several general ledger accounts for this provision, including:

- 145900 Provision For Bad and Doubtful Accounts – used for manual adjustments to the provision as determined by Treasury and Finance
- 145920 Bad & Doubtful Accounts – used for system generated entries from SAP for the Residential and General Service customers; this system is managed by Accenture Business Services BC (ABS)
- 145052 Accounts Rec - Adjust Account – a control account used for reporting purposes, to remove A/R over 180 days from the A/R reported in financial statements, as requested by the auditors (KPMG in F2011). Each quarter, the balance in G/L 145920 is transferred into this account.

Accounts Receivable (A/R): Amounts owing to BC Hydro are recorded on the balance sheet in various general ledger accounts.

- 145000 Electric Accounts Receivable – for Residential and General Service accounts from the SAP system managed by ABS
- 145060 Electric A/R – Transmission – for large Industrial and Transmission customers

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FOR GENERATIONS

Bad Debt for Residential and General Service Customers

Residential, medium general service and large general service customers are managed in the same manner, while large industrial transmission customers are managed with a different process by the Treasury department.

Credit and Collections Process Overview

Utilities are unique from most other business models in that customers consume the product before they are required to pay for it. In this way, BC Hydro extends credit to each of its customers on a regular basis with the expectation that they will pay once invoices are issued.

Credit and collections policies first come into play when a customer applies for service. At that time, customers are screened to determine if they have outstanding balances from other current or prior accounts, or are closely associated (e.g., spouse, roommate) with outstanding balances. In these cases, the application for service is not granted until any outstanding debts are paid.

Once an application for service is approved, credit is then granted to customers who have a proven record of payment with BC Hydro or have passed a credit worthiness check. This mitigates the risk of financial loss caused by unpaid bills based on the prior behaviour of the customer. To establish credit worthiness, a customer can provide one of the following:

1. Credit Bureau Check – the preferred option, done while the customer is on the phone, after getting their verbal agreement, through the Equifax online system
2. Credit Reference Letter – for example, from another utility

If credit worthiness cannot be established, a form of security may be held to apply them to the customers' final bill if it is left unpaid. Non-residential customers are required to provide a security deposit or a bank letter. Residential customers are normally asked to provide a cash security deposit.

Security Deposits

As defined in the Electric Tariff, the security deposit is either 2 or 3 months times the average monthly consumption cost for that premise, depending on billing cycle. The deposit is automatically refunded after one year of on-time payments. In practice, for residential accounts security deposits are only requested if the calculated security deposit is at least $110.

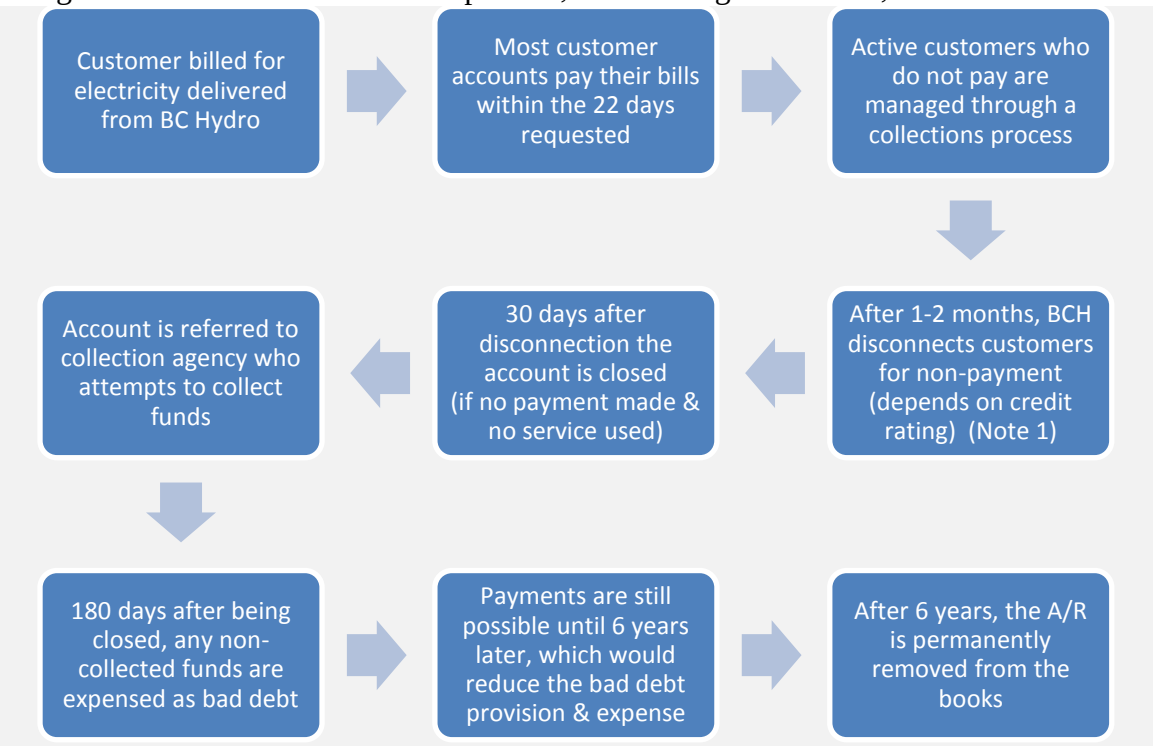
As an alternative to a security deposit a customer can also select the “Pay As You Go” program; however, this pre-pay program is not generally used.

In addition to requiring a security deposit when initially applying for service, BC Hydro may also require a security deposits for existing customers if their payment history becomes poor. In either case, interest is paid on security deposits at BC Hydro’s weighted average cost of borrowing, which is currently 4.28%.

Collections Processes

Credit and Collection processes are overseen by Customer Service Operations and managed by Accenture Business Services of BC (ABS). ABS processes are documented in their ACE system (ABS Centre of Excellence – link). The BC Hydro processes are documented in the One Hydro Business Process Wiki (on HydroShare - link) or are with the Customer Service Operations team.

A high level view of the collections process, from billing to bad debt, is shown below.



Note 1: Customers are not always disconnected for a variety of reasons, and can remain in active A/R for a long time. Conversely, a 'good' customer account can go directly to a closed account, for example, if the customer requests a move-out without a corresponding move-in (e.g. moving out of province).

Dunning Process

The collections process, or dunning process, involves methodically communicating with customers to ensure the collection of accounts receivable. Communications progress from reminders to letters and phone calls and actions by collections agencies as accounts become more past due. The steps taken differ based on the credit worthiness of the customer. A more detailed timeline view of the dunning process is shown below.

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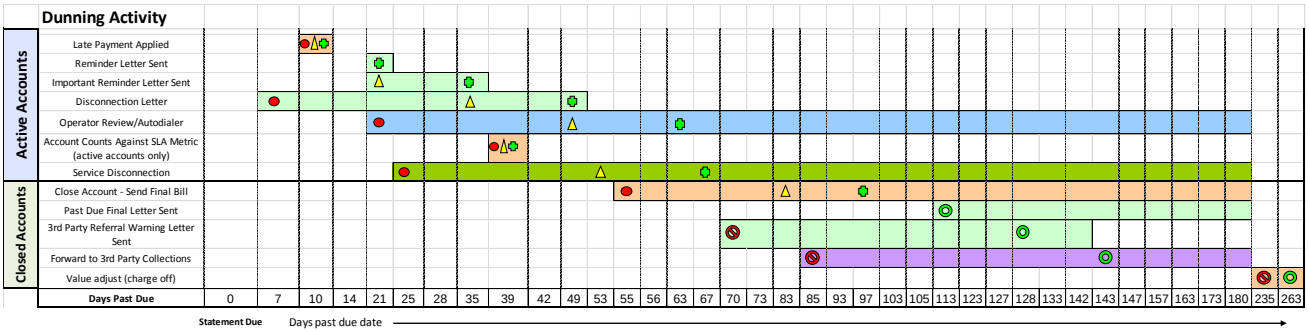


Legend

Customer Segment (Dunning Procedure)	CW Range	Symbol	Type of Action
Bad Active Account (also includes new customers with less than 1 year history, regardless of their standing, who have not passed a credit check)	>=326	●	Bill Activity/Messages
Medium Active Account	151-325	△	Letters
Good Active Account	0-150	✚	Calls
Good Closed Account	0-240	○	Field Activity/Disconnect
Bad Closed Account	>=241	⊘	Third Party Collections

The table below provides an explanation of the steps in the dunning process.

Dunning Action (minimum $30 for active accounts, $10 for closed accounts)	Manual or Auto	Comments
Late Payment Applied	Auto	Late payment applied after 7 days.
Reminder Letter Sent	Auto	This letter applies only to good customers and is sent 21 days after the due date
Important Reminder Letter Sent	Auto	Applies to good and medium customers and is sent 21 and 35 days respectively after the due date. If customer does not already have a security deposit on file, a security deposit warning is printed on this letter
Disconnection Letter	Auto	Applies to all customers. Sent 7 days after the due date for bad and new customers, 21 days for medium customers and 49 days for good customers. If customer does not already have a security deposit on file, a deposit is assessed at this time
Operator Review/Autodialer	Manual	All customers can either be called by the autodialer or a credit agent depending on the process starting at 14 days after the disconnection letter. Should an account remain unpaid, it will be reviewed and called every 10-14 days (depending on age) in perpetuity until the account is closed. Accounts only enter operator review if >$70
Account Counts Against SLA Metric	Auto	All active arrears count against our SLA here, 60 days after the invoice date. Credit department currently uses this threshold to help prioritize accounts
Service Disconnection	Manual	The dates above are the minimum times to disconnect. Service can be disconnected a minimum of 4 days after the Autodialer/Manual call step, and each review/call presents another opportunity to disconnect
Close Account - Send Final Bill	Manual	Accounts are closed 30 days after disconnection provided there has been no payment on the account and no consumption on the meter
Past Due Final Letter Sent	Auto	This letter applies only to good final accounts - sent 30 days after the final bill date
3rd Party Referral Warning Letter Sent	Auto	For good final accounts sent 15 days after the past due final letter. For bad final accounts, sent 15 days after the final bill date

Dunning Action (minimum $30 for active accounts, $10 for closed accounts)	Manual or Auto	Comments
Forward to 3rd Party Collections	Auto	For good final accounts, this occurs 30 days after the referral warning letter (75 days from the final bill date). For bad final accounts, this occurs 15 days after the referral warning letter (30 days from the final bill date)
Value adjust (charge off)	Auto	For all final accounts, this occurs 180 days from the date of the final bill

Collection Agency Process

Collection agencies are used to assist in the collections process, after ABS has exhausted its dunning activities. BC Hydro uses four collections agencies. Only closed accounts are referred to collection agencies. These uncollected accounts are first assigned to one agency (the primary agency) and if they are unable to collect after 180 days, the account is reassigned to a secondary agency where it remains until collected or until the 2 year Statute of Limitations expires.

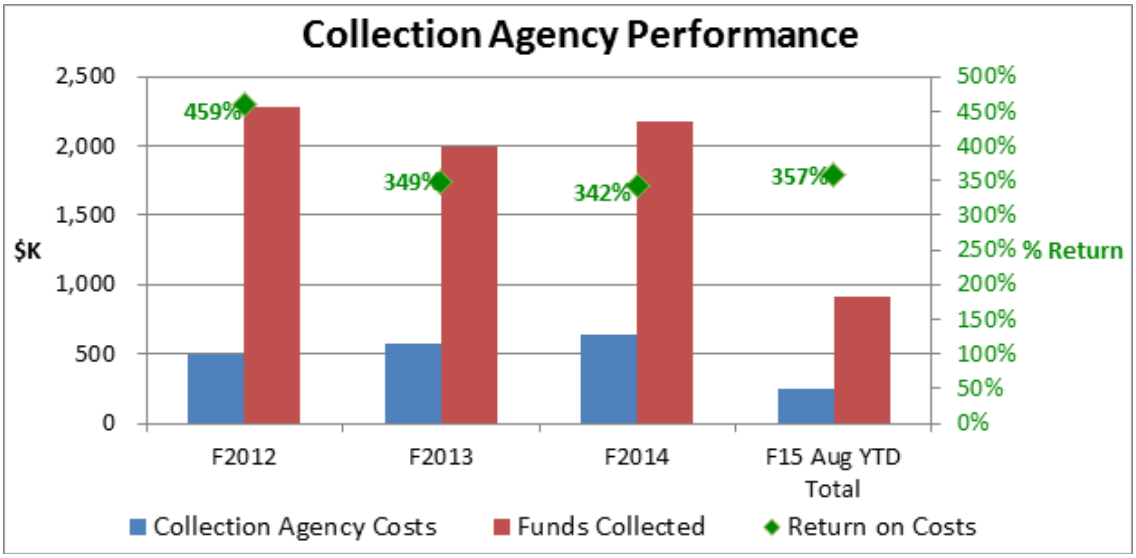
Uncollected accounts with balances under $25 are not referred to collection agencies and are automatically expensed as bad debt. Uncollected accounts over $10,000 are handled in a specialize manner.

Since F2012, the average recovery is 12% of A/R, with the primary agency collecting 16% and the secondary agency collecting 7%. These averages are higher than Fortis BC (a comparable peer) who collects 9%, but are lower than the Canadian Electric Association (CEA) industry average of 14%. This performance is tracked by Customer Care.

Collection agency costs are based on a commission rate schedule, which pays more for collecting on older accounts.

Referral Time	Commission Rate
Less than 90 days	17%
90-120 days	20%
121-134 days	23%
135 days and greater	25%
Secondary agency (>180 days)	40%

Historical collection agency performance is shown in the graph below. The average return has been about 350% over the past 2 ½ years, which translates into an average commission rate of 29%.



Provision Estimate

The bad debt provision for Residential and General Service customers is based on the likelihood of Accounts Receivable becoming bad debt. The probability is estimated with ABS and factors in historical results. These estimates are reviewed quarterly and the provision is revised as necessary. One bad debt entry is automated and occurs when closed accounts hit 180 days. At this point, the full amount is expensed as bad debt in a process referred to as 'value adjusted'.

Aging of A/R	Estimate of Bad Debt % *	Rationale
Active A/R ≤180 days	0%	Still actively being pursued for collection
Active A/R > 180 days	100% of YTD average	Conservative estimate that the entire amount will not be collected
Closed A/R 0-29 days	~ 35% *	Estimate reviewed quarterly, 6 month lag
Closed A/R 30-59 days	~ 55% *	Estimate reviewed quarterly, 5 month lag
Closed A/R 60-89 days	~ 60% *	Estimate reviewed quarterly, 4 month lag
Closed A/R 90-180 days	~ 70% *	Estimate reviewed quarterly, 3 month lag
Closed A/R > 180 days	100%	Automated system generated entry each month
*Estimate based on review of closed A/R over 180 days compared to balance in each A/R 'bucket'.		

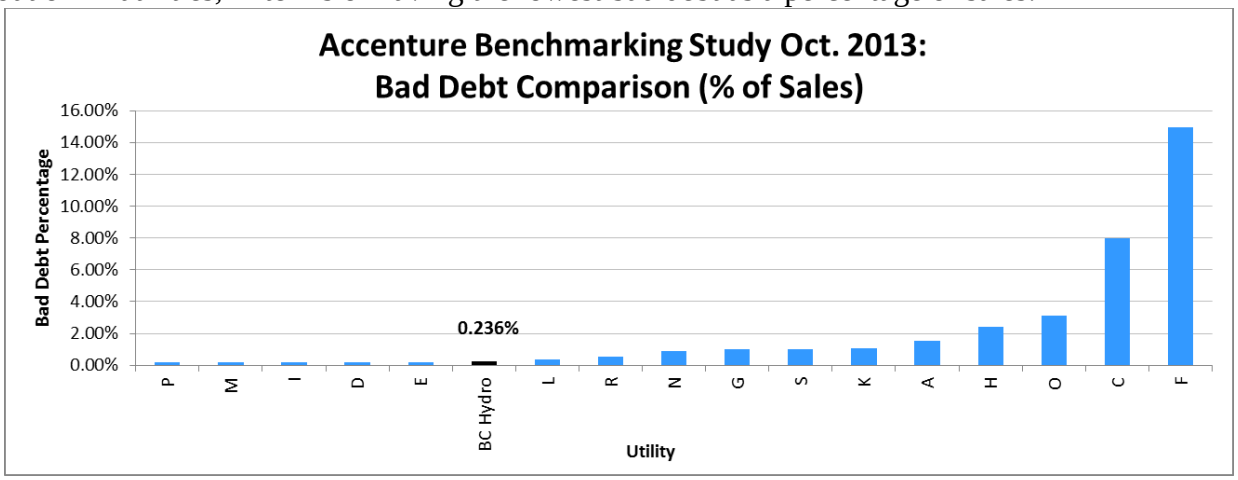
Forecasting Bad Debt Expense as a Percentage of Sales

Bad debt expense is historically averaging 0.24% of billed sales, using an 8 to 9 month lag of when billed sales become bad debt. This factor is used to estimate annual bad debt expense in G/L 660700 under the Customer Care business group.

Estimates of monthly curving of bad debt expense is based on historical curving of billed sales and also factors in the reporting of bad debt. Reporting is done weekly on Sundays, so months

that have 5 Sundays have 5 weeks of data. This is factored in to the curving estimates for annual budgets.

An industry benchmark survey conducted by Accenture in October 2013 ranked BC Hydro 6th out of 17 utilities, in terms of having the lowest bad debt as a percentage of sales.



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Accounting Entries

Sample journal entries, for each step of the process, are shown below. The numbers are fictitious and not necessarily representative of the historical values.

Simplified Accounting Life Cycle of 1 Bad Debt Entry: Residential and General Service Customers

($ thousand)

			Income Statement GL Accounts				Balance Sheet GL Accounts									
			Revenue		Bad Debt Expense		Accounts Receivable		Cash		Bad & Doubtful		Provision For B/D Accounts		Accounts Rec - Adjust Account	
			[various GL 410xxx]		[GL 666070]		GL 145000		[various GL 130xxx]		GL 145920		GL 145900		[GL 145052]	
Date	Action	Notes														
30-Apr-2014	Bill customers			300,000			300,000									
30-May-2014	Receive Payments	example of normal payments						250,000	250,000							
14-Jul-2014	Disconnect and close non-paying accounts	(no journal entry)														
10-Jan-2015	Closed Accounts at 180 days are expensed	System generated ('value adjusted')			720							720				
8-Jan-2021	Collect funds from closed account (>180d to 6yrs)	Reduces the expense				86					86					
	Record cash received, reduce A/R.	similar to normal payment						86	86							
Quarterly	Transfer Provision to Adjustment account for reporting	manual									634					634
9-Jan-2021	After 6 years, permanently remove A/R from books customers	System generated						634			634					
Quarterly	Transfer Provision to Adjustment account for reporting	manual										634			634	
Quarterly	Review A/R aging and assess if provision is sufficient	manual entry in a separate account			33									33		

Additional notes regarding the accounting system, CCS:

- CCS uses Open Item Accounting where each transaction or line item is handled individually based on its assigned due date. In the case of multiple overdue bills, the oldest line items or charges will be processed first.

- Value Adjustment is the system term used to refer to the automatic accounting entry that expenses uncollected accounts after they have been closed for 180 days.
- Accounts then remain in the system for 6 years, which allows customer service agents to investigate if customers who are requesting a new account have an outstanding balance from a previous account.
- Write-off means the account balances are permanently removed from the system, which has no impact on bad debt expense.

Additional information on ABS processes can be found on the ACE website at:
http://edmccsmop01/ace/credit/content/!GI/Write%20Off.htm
http://edmccsmop01/ace/credit/content/!GI/Value%20Adjustment.htm#Topic1

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FOR GENERATIONS

Bad Debt for Large Industrial & Transmission Customers

With less than 200 large industrial and transmission customers, and significant credit risk associated with them, the provision for bad debt is managed with additional scrutiny.

Process Overview & Provision Estimate

The bad debt provision is not set up automatically; rather, it is reviewed monthly by the Treasury department and adjustments to the provision are made quarterly, as needed.

The bad debt provision is calculated by the following formula:

Customer's average 30-day A/R balance * Expected default frequency * (1 - Recovery rate)

Where:

- A customer's expected default frequency (EDF) score from Moody's KMV (Kealhofer, McQuown and Vasicek) credit analysis model, which represents the expected default probability for a customer within the next year. A customer's EDF is multiplied by its estimated 30 days accounts receivable amount to derive the customer's individual monthly gross bad debt provision amount.
- For those customers without an available Moody's KMV EDF score, an industry sector EDF or a portfolio EDF may be applied.
- A 10% recovery rate (or a 90% loss rate) is currently assumed these customers based on recent experience at BC Hydro. Historically a 20% recovery rate was used; however, this was reduced based on several customer experiences that recovered only 0% to 4%.

Accounting Entries

Sample journal entries, for each step of the process, are shown below.

Accounts Receivable and Bad Debts Journal Entries: Large Industrial Transmission Customers
($thousand)

			Income Statement GL Accounts				Balance Sheet GL Accounts					
			Revenue		Bad Debt Expense		Electric A/R - Transmission		Bad Debt Provision		Cash	
			[various GL 410xxx]		[GL 666070]		[GL 145060]		[various GL 145052, GL 145900, GL 145920]		[various GL 130xxx]	
Date	Action	Notes										
31-Aug-2013	Bill customers			70,000			70,000					
22-Sep-2013	Receive Payments	(example of normal payment)						45,000				45,000
20-May-2014	Disconnect and close non-paying accounts	(no journal entry)										
Quarterly	Review Treasury provision estimate monthly and adjust quarterly.				300					300		
18-May-2020	Collect funds from closed account (180days-6yrs)	Reduces the expense. Typically 27% of closed A/R.				70			70			
		Record cash received, reduce A/R.						70				70
19-May-2020	After 6 years, permanently remove A/R from books customers							6	6			

BC hydro
FOR GENERATIONS

Factors Influencing Bad Debt

Some key factors that affect non-payment by customers include:

- Economic Conditions: Bad debt is higher during periods of higher unemployment and higher bankruptcies (both business and personal), as customers experience financial hardship and are less able to pay their bill.
- BC Hydro Processes: There are several processes that affect bad debt. The root cause is the granting of credit itself and the security deposit options, as well as the processes around those options. As an example, during the implementation of the smart metering initiative (SMI), when the meter reading workforce was reduced, there was less manpower to disconnect customers for non-payment, which resulted in higher A/R. This eventually drove a spike in closed A/R and then resulted in higher bad debt expense. Another example is remote disconnect/reconnect functionality that reduces the time that it takes to disconnect a customer (and reduced Active A/R). Although increased disconnection activity does limit the financial exposure to non-payment of bills, it has also accelerated the time for accounts to be closed, which may have affected bad debt expense in the transition to a new SMI-based collection model.
- Accenture Processes: Accenture manages the credit and collection activities. Ongoing process improvements help reduce bad debt, for example, by targeting high dollar accounts, increasing workforce capacity, reducing customer false payments, and additional training on best practices.
- Collection Agency Processes: The effectiveness of collection agencies can improve recovery of bad debt.
- Government Decisions: As an example, the Meter Choices Program allowed customers to retain a legacy meter or non-communicating meter that drove the need for more workers to read meters (for billing purposes) and reduced their ability to do disconnects. Further, all collections activities were stalled for these customers, while the matter was before the BCUC.
- Customer "Gaming": Although most customers are considered honest, some look for ways to avoid paying for electricity they have consumed. This includes, for example, applying for service under false names, or closing delinquent accounts and attempting to re-open them under other names. In many instances involving large balances it is suspected that the customers may be involved in illegal activities (e.g., marijuana grow operations).

Current Activities

Customer Care has initiated a project to review A/R and bad debt processes in view of new capabilities and requirements of smart meters, as well as changes more generally in customer behaviour and the use of electronic and self-service channels. Activities include:

- A concentrated effort to clean-up the backlog in Active A/R dunning, which accumulated during the transition to smart meters.
- Detailed segmentation of the accounts that become aged Closed A/R and bad debts, to better understand the specific issues that contribute to them not paying bills (i.e., as

opposed to macro-economic considerations such as interest rates and employment). For example, dwelling type, location, rented vs. owned, etc.

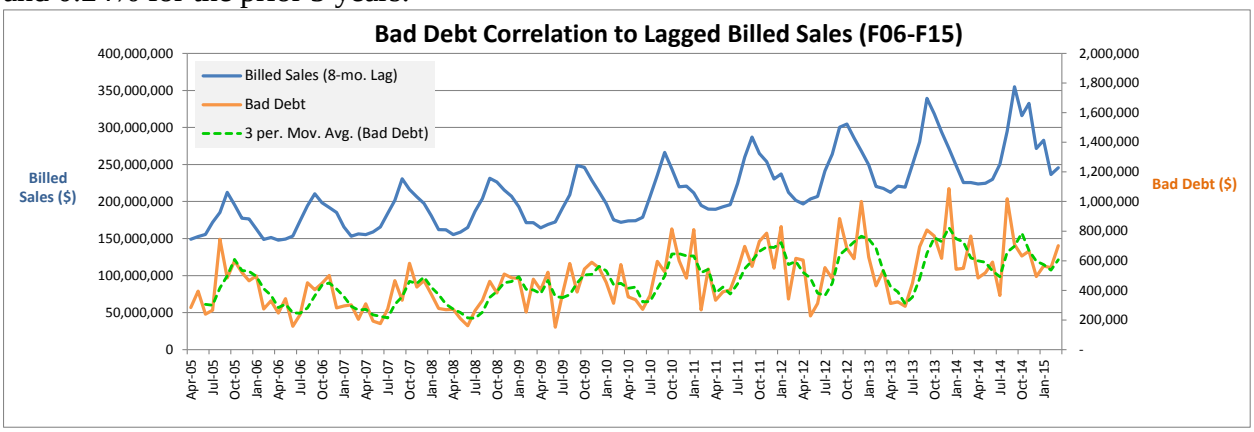
- A review of security deposit policies, with potential changes that could include proposed changes to the Electric Tariff during the upcoming Rate Design Application.
- With Revenue Assurance, improving the processes for early identification of accounts that could become large write-offs if standard dunning processes are followed.

BC hydro
FOR GENERATIONS

Appendix A: Historical Bad Debt

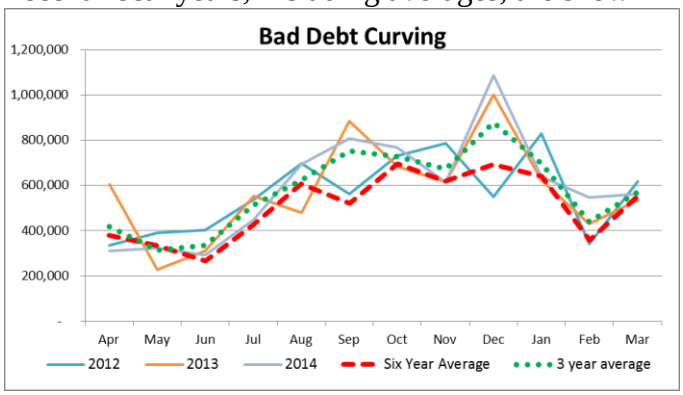
Residential and General Service:

The chart below shows that Residential and General Service bad debt expense is highly correlated to billed sales from 8 to 9 months prior, average 0.22% of sales for the prior 10 years, and 0.24% for the prior 5 years.

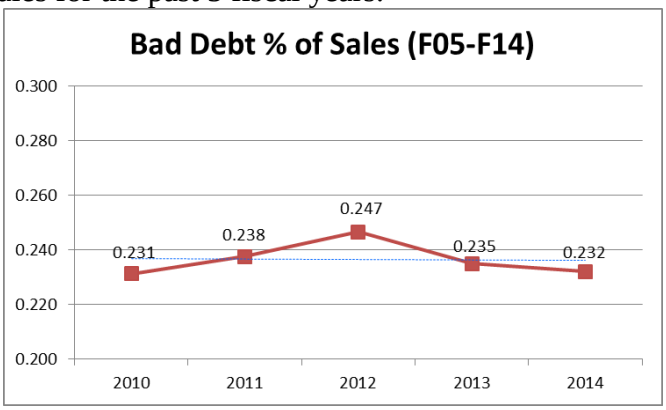


Source: M:\F&BS\Business Services\BUSSERV\Customer_Care\Provision & Bad Debt\F15\5 Bad Debt Aug2014 with new Forecast.xlsx

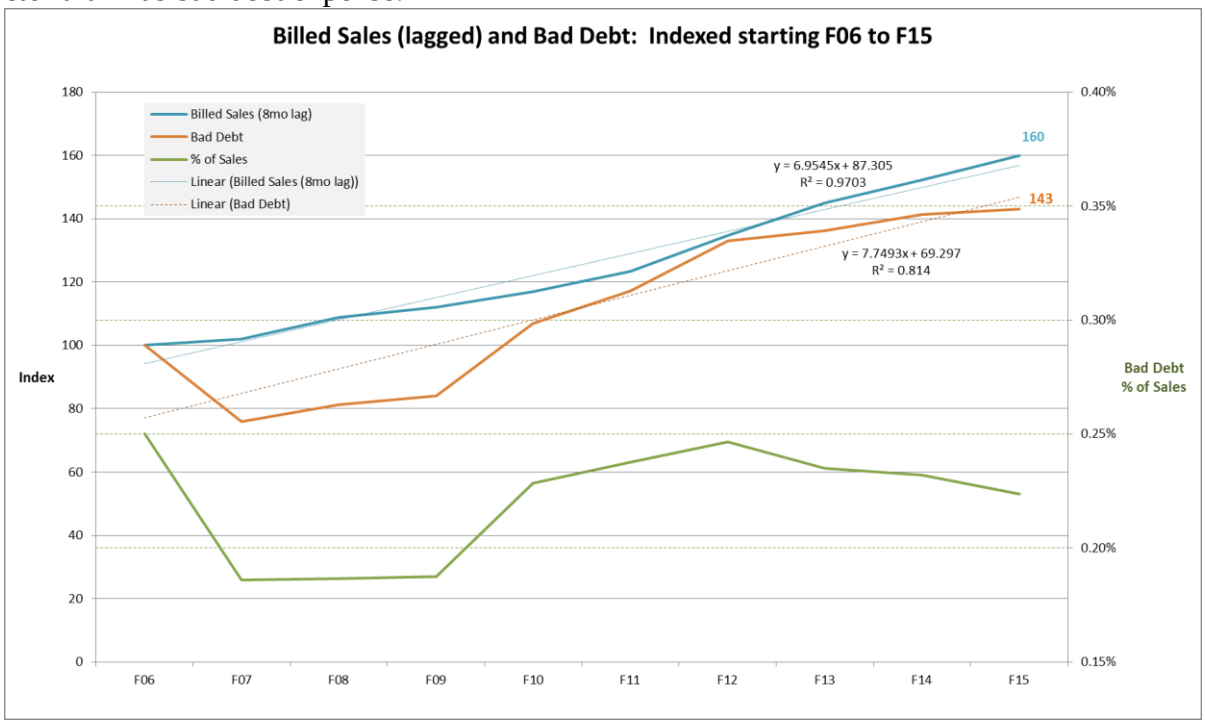
Monthly curving from recent fiscal years, including averages, are shown in the graph below.



Bad debt expense (i.e. closed 180 days and value adjusted) has been consistent at 0.24% of annual billed electric sales for the past 5 fiscal years.

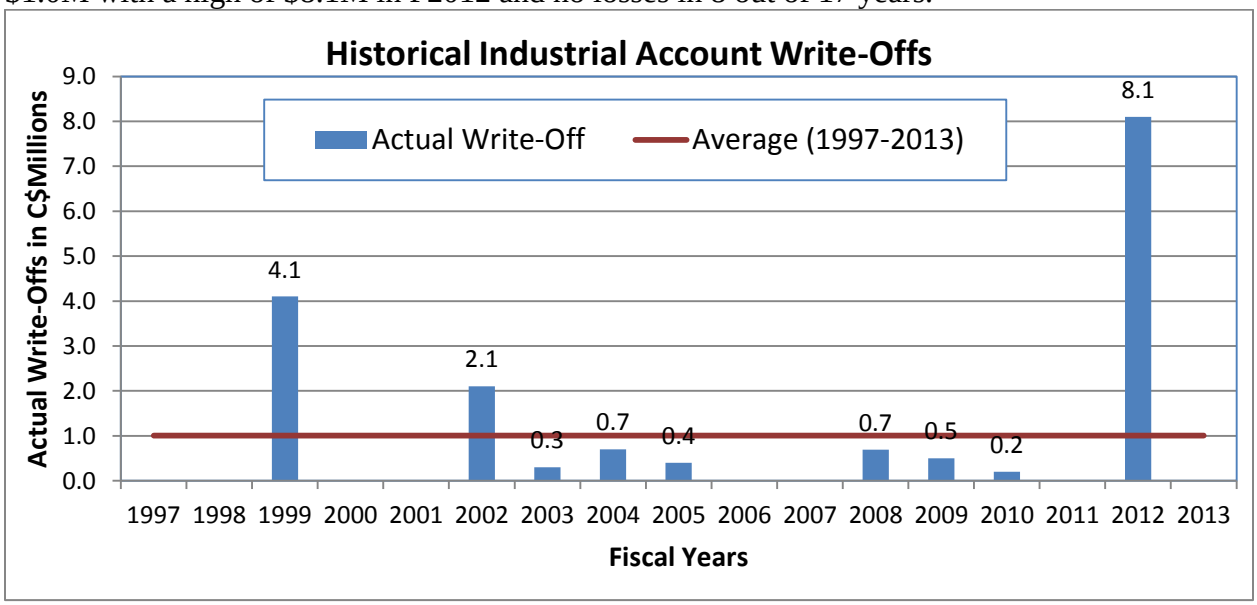


This is also represented in the following graph that also has an indexed view of Sales and Bad Debt, starting at the value 100 in F06. This shows Sales have increased by a slightly higher factor than has bad debt expense.



Industrial and Transmission:

The chart below shows bad debt write-offs from F1997 to F2013. The average write-off has been $1.0M with a high of $8.1M in F2012 and no losses in 8 out of 17 years.



BC hydro
FOR GENERATIONS

Appendix B: General Ledger Account Information

The current G/L account reconciliations are shown below, for reference.

G/L 145900 Provision For Bad and Doubtful Accounts

ACCOUNT RECONCILIATION				
Account Reconciled:		**SAP 145900 (Corporate)**		
Company Code:		**BCH1**		
Description:		Provision For Bad Debt Accounts		
Reconciliation Date:		**July 31, 2014**		
Outstanding items in the GL:				
Profit Center 1870				
Bad debt provision re: Transport Canada Receivable-Rock Bay				$ (1,600,000.00)
Reversal of Rock Bay Receivable due to Settlement in MayF13				1,600,000.00
General Ledger Balance - Profit Centre 1870 (Corporate)				**$ -**
Profit Centre 5000				(8,202,339.15)
Details of O/S balance:				
	Residential & General Service			
		Residential-Provision for BC hydro's Bad debt	(3,969,442.02)	
		March 2012 added provision for Residential & Small Commercial	(978,541.13)	
		Nov. 2012 Provision transferred to Transmission	300,000.00	
		Total Residential & General Service	(4,647,983.15)	
	Transmission			
	Large Industrial-Aug02 BC Gas	(15,292.06)		
	Large Industrial Provision in F2006	(900,000.00)		
	Large Industrial Provision in F2008	(1,000,000.00)		
	Large Industrial Provision in F2009	(3,500,000.00)		
	Adjustment to Large Industrial Provision in F2009	400,000.00		
	Large Industrial Provision in F2009-bankrupt-Abitibi Bowater-Acct# 47001	83,818.97		
	Large Industrial Provision in F2009-bankrupt-Sun Wave Forest Products-Acct# 43013	75,270.56		
	March 2012 added provision for Large Industrial-(Mainly due to Catalyst)	(4,030,456.31)		
	Nov. 2012 Provision transferred from Residential and General Service	(300,000.00)		
	Mar 31, 2013 Decrease Transmission Provision due to Settlement of Catalyst	8,368,302.84		
	Transmission Provision- as of March 31, 2014		(818,356.00)	
	Mar 31, 2014 Increase Transmission Provision due to Catalyst		(2,736,000.00)	
		Total Transmission	(3,554,356.00)	
		Total	**(8,202,339.15)**	
General Ledger Balance - Corporate profit centres				**$ (8,202,339.15)**

J:\Finance\Business Support Services\RECONCILIATIONS (FISCAL)\Provision Accounts\145900 - Provision For Bad and Doubtful Accounts\F15\F15 GL 145900 Provision for Bad Debt reconciliation.xls

BC hydro
FOR GENERATIONS

G/L 145920 Bad & Doubtful Accounts

RECONCILIATION OF ACCOUNT 145920					
(GL010700 Written Off Accts Receivable & 023300 Bad & Doubtful Accounts - PS)					
BAD & DOUBTFUL ACCOUNTS					
BALANCE AS AT July 31, 2014					
Ending Balance per SAP GL as of Mar. 31 , 2013					**0.00**
Ending Balance per SAP GL as of March 31, 2014					**0.00**
	Increase in Bad and Doubtful Account Balance	Q1	(2,250,278.29)		
	Collection/Uses during the period	Q1	1,987,883.31		
	JV - F15Q1 to move to GL145052-AR ADJ	Q1		262,394.98	
	Balance after F15Q1				**0.00**
	Increase in Bad and Doubtful Account Balance	Q2	(579,582.40)		
	Collection/Uses during the period	Q2	531,116.07		
	JV - F15Q1 to move to GL145052-AR ADJ	Q2			
	Total Balance as of July 31,2014				**(48,466.33)**
Trial Bal. (Corporate only) as of July 31, 2014					**(48,466.33)**
					0.00

J:\Finance\Business Support Services\RECONCILIATIONS (FISCAL)\Provision Accounts\145920 - Bad and Doubtful Accounts\F15\GL 145920 BD Allowance July14.xlsx

BC hydro
FOR GENERATIONS

G/L 145052- Acc Rec – Adj Acct

BC HYDRO & POWER AUTHORITY						
RECONCILIATION OF ACCOUNT 145052						
ACCOUNT RECEIVABLE ADJUSTMENT						
BALANCE AS AT July 31, 2014						
Carry Forward as of April 1, 2012						$ (28,886,083.53)
				Including PST/GST/HST		
	Moved in on F2013 and F2014					(7,616,519.20)
	Amount moved from GL 145920 for F2015 Q1-To Clear the 180 day old account balance in AR 145000-Doc# 101450027		F15Q1	(235,057.06)		
	Subtotal					$ (7,851,576.26)
Ending Balance per SAP GL as of July 31, 2014						$ (36,737,659.79)
Trial Balance as of July 31, 2014						(36,737,659.79)

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G/L 145000 – Electric AR

BC HYDRO & POWER AUTHORITY
RECONCILIATION OF ACCOUNT 145000 (PS GL010000)
ELECTRIC ACCOUNTS RECEIVABLE (LIGHT, POWER AND GAS)
BALANCE AS AT July 31, 2014

Profit Centre Month	DCEO 5000	DCEO 5010	DCEO 5110	Corp 1870	Other pwr Sply OthEP 2420	D-Other 4000	D-OH Lines 4050	D-UG Lines 4060	D-Meters 4090	Total
CFwd	455,213,090.66	1,454,898.15	7,920.00	(120,311,880.19)	-	14,246.15	416,169.85	412,060.03	3,516.81	**337,210,021.46**
Apr	(27,507,116.29)	29,341.22	(7,164.00)	(1,887,036.33)		3,320.62	(3,505.98)	(83,676.59)		**(29,455,837.35)**
May	(420,618.59)	90,314.95	(472.50)	261,802.42	(26,075.00)	2,176.31	(8,734.22)	40,670.93	-	**(60,935.70)**
Jun	(37,174,593.34)	74,633.52	-	(881,678.27)	-	(2,881.73)	8,795.62	30,160.88	-	**(37,945,563.32)**
Jul	822,855.96	70,348.48	(283.50)	(1,167,726.07)	26,075.00	983.10	(31,623.88)	17,818.60		**(261,552.31)**
Aug										-
Sep										-
Oct										-
Nov										-
Dec										-
Jan										-
Feb										-
Mar										-
Total	**390,933,618.40**	**1,719,536.32**	**-**	**(123,986,518.44)**	**-**	**17,844.45**	**381,101.39**	**417,033.85**	**3,516.81**	**269,486,132.78**
Balance of Accounts Receivable per SAP GL as of July 31, 2014										
							Total AR per AR Aging Schedule (Active AR)			$ 210,515,930.54
							Total AR per AR Aging Schedule (Closed AR)			$ 45,900,744.61
Total AR		**269,486,132.78**					SAP/ Lodestar variance due to Timing Difference			13,069,457.63
									Total:	$ 269,486,132.78
										-
per Trial Bal		**269,486,132.78**								
Diff		-								

J:\CC&C\F&BS\General Accounting\GL Reconciliations\F15_SAP GL\04-Jul'14\GL 145000 Accounts Receivable_July'14.xlsx

199.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.199.1 Please provide all written studies currently within BC Hydro's custody or control, whether or not prepared by or for BC Hydro, that explicitly assess the extent to which the following activities reduce residential bad debt:

(a) Cash security deposits;
(b) Deferred payment agreements;
(c) Disconnections for nonpayment;
(d) Field collections;
(e) Call center collection calls;
(f) Budget billing plans;
(g) Late payment charges.

RESPONSE:

(a) Please refer to Attachment 2 to BC Hydro's response to BCOAPO IR 1.198.2.

(c) Please refer to section 4.3 of Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

With respect to (b) and (d to g) BC Hydro does not have studies or analysis on the extent to which the other activities reduce residential bad debt.

200.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.200.1 Please provide all written studies currently within BC Hydro's custody or control, whether or not prepared by or for BC Hydro, that explicitly assess the extent to which the following activities reduce residential arrears:

(a) Cash security deposits;
(b) Deferred payment agreements;
(c) Disconnections for nonpayment;
(d) Field collections;
(e) Call center collection calls;
(f) Budget billing plans;
(g) Late payment charges.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.198.2.

201.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.201.1 Please provide any documents, analyses or reports in BC Hydro's custody or control, whether or not prepared by or for BC Hydro, that indicates, evaluates or otherwise discusses the amount which residential arrears must reach in order for BC Hydro to cost-effectively disconnect service due to the arrearage.

RESPONSE:

While BC Hydro does not have any documents that specifically evaluate the amount which Residential arrears must reach for BC Hydro to cost effectively disconnect service due to arrearage, in BC Hydro's view, the weighted average cost of Dunning and disconnection, which is $15.94 as shown below, is such an amount. The actual cost varies from $6.46 to $187.00 depending on BC Hydro's ability to disconnect the service remotely.

Action		Cost ($)	Weighting (%)	Weighted Cost ($)
Dunning Notices	3 notices x $0.89	2.67	100	2.67
Agent Review	Per BCUC IR 1.124.1	3.79	100	3.79
Remote Disconnection		-		-
Total – Remote		6.46		6.46
Manual Disconnection	Per BCUC IR 1.124.1	180.54	5	9.48
Total – Manual		187.00		15.94

202.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.202.1 Please indicate whether residential late payment charges are compounded. In other words, please indicate whether residential late fees are imposed on unpaid late fees.

RESPONSE:

Yes, in general, Late Payment Charges are compounded. However, the method of calculation in the billing system means this is not always the case because:

- **The Late Payment Charge is calculated separately for (1) the outstanding balance of electricity and standard charges, and (2) outstanding Late Payment Charges that are applied; and**
- **The $30 threshold for application of the Late Payment Charge also applies separately for each of these calculations.**

This means that, in practice, Late Payment Charges are not compounded unless the customer has an outstanding balance of at least $2000 (i.e., $30/1.5 per cent).

203.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.203.1 Please provide a copy of a typical residential notice of disconnection for nonpayment printed in each of the following months:

(a) November 2014
(b) January 2015
(c) April 2015
(d) August 2015

If more than one type of residential disconnection notice is issued, provide a copy of each.

RESPONSE:

BC Hydro had the same FNOD letters for all the months specified. Please refer to Attachment 1 to this IR response which includes the following four types of FNOD letters:

- **Final Notice of Disconnection**
- **Final Notice of Disconnection – Security Deposit required**
- **Final Notice of Disconnection – Certified Cheque or Monday Order required**
- **Final Notice of Disconnection – Non Payment of Security Deposit.**

Attachment 2 to this IR response includes the same four types of FNOD letters reflecting the December 1, 2015 Reconnection Charge change and some language update.

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

May 22, 2015

Account Number: 1234567
For service at: 1234 ANYNAME ST ANYTOWN BC V6B 5A1

Disconnection Notice for Total Amount Owing of $82.24

Our records indicate that payment for the above account is past due.

To prevent disconnection of your BC Hydro service, please pay the total amount owing today. In addition, you need to report your payment by calling 604 224 9376 or 1 800 224 9376 and selecting payment options from the main menu.

You can also report your payment by logging in to your account at **bchydro.com/login**. At the same time, consider setting up a pre-authorized payment plan that many customers find works well with online billing to make paying easier.

If disconnection occurs, the following will need to happen before reconnection:

- the total amount owing must be paid;
- a reconnection charge of up to $355 will be charged and appear on your next bill;
- to prevent fires, we need to confirm that all electrical equipment is turned off or disconnected, particularly those that produce heat such as stoves, space heaters, and irons; and
- preparation may be necessary to reduce the potential for weather-related damage including frozen or burst pipes.

In the event of a disconnection, you can request your service be reconnected. Once you've paid the amount owing, call 604 224 9376 or 1 800 224 9376 and follow the prompts to report your payment and request your service be reconnected. This option is available to most customers at any time and does not require BC Hydro Customer Service assistance.

Sincerely,

BC Hydro Customer Service

FNDNSD

BChydro

Mail To: PO Box 9501 Stn Terminal, Vancouver BC V6B 4N1

Return this portion with your payment
ALL PAYMENTS SHOULD BE MADE PAYABLE TO BC HYDRO

Billing Date	Account Number
May 22, 2015	1234567
Due Date	**Amount Due**
PAST DUE	**$82.24**

Amount Paid

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

34 00 000000053 406 000008224 000000000

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

May 22, 2015

Account Number: 1234567
For service at: 1234 ANYNAME ST ANYTOWN BC V6B 5A1

Disconnection Notice for Total Amount of $1,963.15 Owing Today and Security Deposit of $1,401.00 Required by Jun 2, 2015

Our records indicate that payment for the above account is past due. In addition, several payments have been late and therefore a security deposit is required.

To prevent disconnection of your BC Hydro service, please pay the total amount owing today. In addition, you need to report your payment by calling 604 224 9376 or 1 800 224 9376 and selecting payment options from the main menu. You can also report your payment by logging in to your account at **bchydro.com/login**.

If disconnection occurs, the following will need to happen before reconnection:

- the total amount owing must be paid;
- a reconnection charge of up to $355 will be charged and appear on your next bill;
- to prevent fires, we need to confirm that all electrical equipment is turned off or disconnected, particularly those that produce heat such as stoves, space heaters, and irons; and
- preparation may be necessary to reduce the potential for weather-related damage including frozen or burst pipes.

In the event of a disconnection, you can request your service be reconnected. Once you've paid the amount owing, call 604 224 9376 or 1 800 224 9376 and follow the prompts to report your payment and request your service be reconnected. This option is available to most customers at any time and does not require BC Hydro Customer Service assistance.

The security deposit will be refunded when bills are paid in full by the due date for 12 consecutive months. During this time, interest will be credited to your account and if the account is closed before this occurs then the deposit will be applied to the final bill.

Sincerely,

FNDWSD

BC Hydro Customer Service

BC hydro

Mail To: PO Box 9501 Stn Terminal, Vancouver BC V6B 4N1

Return this portion with your payment
ALL PAYMENTS SHOULD BE MADE PAYABLE TO BC HYDRO
For Security Deposit Only

Billing Date: May 22, 2015
Due Date: **PAST DUE**

Account Number: 1234567
Security Deposit Amount: **$1,401.00**

Amount Paid

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

21 00 000000502 206 000140100 000000000

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

May 22, 2015

Account Number: 1234567
For service at: 1234 ANYNAME ST ANYTOWN BC V6B 5A1

Disconnection Notice for Total Amount Owing of $2,385.41

Our records indicate that payment for the above account is past due.

To prevent disconnection of your BC Hydro service, please pay the total amount owing by certified cheque or money order today. In addition, you need to report your payment by calling 604 224 9376 or 1 800 224 9376 and selecting payment options from the main menu.

You can also report your payment by logging in to your account at **bchydro.com/login**. At the same time, consider setting up a pre-authorized payment plan that many customers find works well with online billing to make paying easier.

If disconnection occurs, the following will need to happen before reconnection:

- the total amount owing must be paid;
- a reconnection charge of up to $355 will be charged and appear on your next bill;
- to prevent fires, we need to confirm that all electrical equipment is turned off or disconnected, particularly those that produce heat such as stoves, space heaters, and irons; and
- preparation may be necessary to reduce the potential for weather-related damage including frozen or burst pipes.

In the event of a disconnection, you can request your service be reconnected. Once you've paid the amount owing, call 604 224 9376 or 1 800 224 9376 and follow the prompts to report your payment and request your service be reconnected. This option is available to most customers at any time and does not require BC Hydro Customer Service assistance.

Sincerely,

BC Hydro Customer Service

FNDCMO

BC hydro

Mail To: PO Box 9501 Stn Terminal, Vancouver BC V6B 4N1

Return this portion with your payment
ALL PAYMENTS SHOULD BE MADE PAYABLE TO BC HYDRO

Billing Date: May 22, 2015
Account Number: 1234567
Due Date: **PAST DUE**
Amount Due: **$2,385.41**
Amount Paid:

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

66 00 000007781 866 000238541 000000000

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

May 22, 2015

Account Number: 1234567
For service at: 1234 ANYNAME ST ANYTOWN BC V6B 5A1

Disconnection Notice for $846.00 Security Deposit Required

Our records indicate that the security deposit required for the above account is past due.

To prevent disconnection of your BC Hydro service, please pay the security deposit today. In addition, you need to report your payment by calling 604 224 9376 or 1 800 224 9376 and selecting payment options from the main menu.

You can also report your payment by logging in to your account at **bchydro.com/login.**

If disconnection occurs, the following will need to happen before reconnection:

- the total amount owing must be paid;
- a reconnection charge of up to $355 will be charged and appear on your next bil;
- To prevent fires, we need to confirm that all electrical equipment is turned off or disconnected, particularly those that produce heat such as stoves, space heaters, and irons; and
- preparation may be necessary to reduce the potential for weather-related damage including frozen or burst pipes.

In the event of a disconnection, you can request your service be reconnected. Once you've paid the amount owing, call 604 224 9376 or 1 800 224 9376 and follow the prompts to report your payment and request your service be reconnected. This option is available to most customers at any time and does not require BC Hydro Customer Service assistance.

Sincerely,

BC Hydro Customer Service

FNDFSD

BC hydro

Mail To: PO Box 9501 Stn Terminal, Vancouver BC V6B 4N1

Return this portion with your payment
ALL PAYMENTS SHOULD BE MADE PAYABLE TO BC HYDRO

Billing Date	Account Number
May 22, 2015	1234567
Due Date	**Amount Due**
PAST DUE	**$846.00**

Amount Paid

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

35 00 000000302 075 000084600 000000000

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

May 22, 2016

Account Number: 1234567
For service at: 1234 ANYNAME ST ANYTOWN BC V6B 5A1

Final Disconnection Notice

Past due	$562.15 due immediately to avoid disconnection
Security deposit	$1,401.00 due by Jun 2, 2015, please contact us to make arrangements if necessary

We haven't received payment for the amount you owe. Please pay your balance immediately, or we'll disconnect your service.

How to avoid disconnection:

1. Pay the past due amount owing immediately;
2. Report your payment by logging into your account at **bchydro.com/login** or by calling 1 800 BCHYDRO.

There have also been several late payments on your account, and that means we'll need to charge a security deposit to continue your service. This deposit is due by Jun 2, 2015, please contact us to make arrangements if necessary.

You'll get your security deposit back when bills are paid in full, by the due date, for 12 consecutive months. For those 12 months, we'll credit the interest to your account. And if you close your account before the end of those 12 months, your security deposit will be applied to the final bill.

How to get your electricity back on if you are disconnected
Once you've paid the past due amount owing, you can report the payment and request your electricity be reconnected by calling 1 800 BCHYDRO (1 800 224 9376) at any time and following the prompts. We'll work to get you reconnected as soon as possible. A reconnection charge of $30 will be charged and appear on your next bill.

If you've been disconnected, it's your responsibility to take whatever steps you can to reduce the likelihood of damage as a result of a disconnection. Before calling to request a reconnection, to prevent the possibility of a fire, please turn off or disconnect all electrical equipment (especially items that produce heat such as stoves, space heaters or irons).

Thank you,

BC Hydro Customer Service

FNDWSD

BC Hydro

Mail To: PO Box 9501 Stn Terminal, Vancouver BC V6B 4N1

Return this portion with your payment
ALL PAYMENTS SHOULD BE MADE PAYABLE TO BC HYDRO

Billing Date	May 22, 2016	Account Number 1234567
Due Date	**PAST DUE**	Amount Due **$1,401.00**
		Amount Paid

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

21 00 000000502 206 000140100 000000000

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

May 22, 2016

Account Number: 1234567
For service at: 1234 ANYNAME ST ANYTOWN BC V6B 5A1

Final Disconnection Notice for a Security Deposit amount owing: $606.00

We haven't received payment for the amount you owe for the security deposit on your BC Hydro account. Please pay your balance immediately, or we'll disconnect your service.

How to avoid disconnection:

1. Pay the total amount owing for the security deposit immediately;
2. Report your payment for the security deposit by logging into your account at **bchydro.com/login** or by calling 1 800 BCHYDRO (1 800 224 9376).

How to get your electricity back on if you are disconnected

Once you've paid the total amount owing you can report the payment and request your electricity be reconnected by calling 1 800 BCHYDRO (1 800 224 9376) at any time and following the prompts. We'll work to get you reconnected as soon as possible. A reconnection charge of $30 will be charged and appear on your next bill.

If you've been disconnected, it's your responsibility to take whatever steps you can to reduce the likelihood of damage as a result of a disconnection. Before calling to request a reconnection, to prevent the possibility of a fire, please turn off or disconnect all electrical equipment (especially items that produce heat such as stoves, space heaters or irons).

Thank you,

BC Hydro Customer Service

FNDFSD

BC Hydro

Mail To: PO Box 9501 Stn Terminal, Vancouver BC V6B 4N1

Return this portion with your payment
ALL PAYMENTS SHOULD BE MADE PAYABLE TO BC HYDRO

Billing Date	Account Number
May 22, 2016	1234567
Due Date	**Amount Due**
PAST DUE	**$846.00**

Amount Paid

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

35 00 000000302 075 000084600 000000000

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

May 22, 2016

Account Number: 1234567
For service at: 1234 ANYNAME ST ANYTOWN BC V6B 5A1

Final Disconnection Notice for Total Amount Owing of $2,385.41

We haven't received payment for the amount you owe. Please pay your balance immediately, or we'll disconnect your service.

How to avoid disconnection:

1. Pay the total amount owing by certified cheque or money order immediately;
2. Report your payment by logging into your account at **bchydro.com/login** or by calling 1 800 BCHYDRO (1 800 224 9376).

How to get your electricity back on if you are disconnected

Once you've paid the total amount owing, you can report the payment and request your electricity be reconnected by calling 1 800 BCHYDRO (1 800 224 9376) at any time and following the prompts. We'll work to get you reconnected as soon as possible. A reconnection charge of $30 will be charged and appear on your next bill.

If you've been disconnected, it's your responsibility to take whatever steps you can to reduce the likelihood of damage as a result of a disconnection. Before calling to request a reconnection, to prevent the possibility of a fire, please turn off or disconnect all electrical equipment (especially items that produce heat such as stoves, space heaters, or irons).

Thank you,

BC Hydro Customer Service

FNDCMO

BC Hydro

Mail To: PO Box 9501 Stn Terminal, Vancouver BC V6B 4N1

Return this portion with your payment
ALL PAYMENTS SHOULD BE MADE PAYABLE TO BC HYDRO

Billing Date: May 22, 2016
Due Date: **PAST DUE**

Account Number: 1234567
Amount Due: **$2,385.41**
Amount Paid:

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

66 00 000007781 866 000238541 000000000

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

May 22, 2016

Account Number: 1234567
For service at: 1234 ANYNAME ST ANYTOWN BC V6B 5A1

Final Disconnection Notice for Total Amount Owing of $82.24

We haven't received payment for the amount you owe. Please pay your balance immediately, or we'll disconnect your service.

How to avoid disconnection:

1. Pay the total amount owing immediately;
2. Report your payment by logging into your account at **bchydro.com/login** or by calling 1 800 BCHYDRO (1 800 224 9376).

How to get your electricity back on if you are disconnected

Once you've paid the total amount owing you can report the payment and request your electricity be reconnected by calling 1 800 BCHYDRO (1 800 224 9376) at any time and following the prompts. We'll work to get you reconnected as soon as possible. A reconnection charge of $30 will be charged and appear on your next bill.

If you've been disconnected, it's your responsibility to take whatever steps you can to reduce the likelihood of damage as a result of a disconnection. Before calling to request a reconnection, to prevent the possibility of a fire, please turn off or disconnect all electrical equipment (especially items that produce heat such as stoves, space heaters or irons).

Thank you,

BC Hydro Customer Service

FNDNSD

BC Hydro

Mail To: PO Box 9501 Stn Terminal, Vancouver BC V6B 4N1

Return this portion with your payment
ALL PAYMENTS SHOULD BE MADE PAYABLE TO BC HYDRO

Billing Date	Account Number
May 22, 2016	1234567
Due Date	**Amount Due**
PAST DUE	**$82.24**

Amount Paid

JOHN DOE
1234 ANYNAME ST
ANYTOWN BC V6B 5A1

34 00 000000053 406 000008224 000000000

204.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.204.1 By month for each month January 2012 to present inclusive, please provide:

(a) The number of new deferred payment arrangements entered into;
(b) The average downpayment (in dollars) of deferred payment arrangements entered into disaggregated by the arrearages at the time the deferred payment arrangement is sought;
(c) The average term (in months) of deferred payment arrangements entered into;
(d) The average dollar amount of arrears made subject to the deferred payment arrangement disaggregated by their term (in months) of the payment arrangement agreement;
(e) The average monthly installment of deferred payment arrangements disaggregated by their term (in months) of the payment arrangement agreement;
(f) The distribution of new deferred payment arrangements by their term (in months);
(g) The number of defaulted deferred payment arrangements;
(h) The number of defaulted deferred payment arrangements disaggregated by their term (in months) of the payment arrangement agreement;
(i) The number of completed (or "successful") deferred payment arrangements disaggregated by their term (in months) of the payment arrangement agreement.

RESPONSE:

For the context of this IR, BC Hydro assumes "deferred payment arrangements" means "Installment Plans". BC Hydro's Installment Plan terms are normally three months or less. However as noted in section 5.4.2 of Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1, BC Hydro is investigating the practicality of offering longer payment terms of up to six or eight months.

The information provided is disaggregated by number of installments in Installment Plans instead of "months" as requested. For (g) (h) and (i), BC Hydro can only provide the information based on the Installment Plan status at the time the data was extracted on December 10, 2015. Some Installment Plans, especially the recent ones, were not included because they are still within their payment terms and can yet to be determined as defaulted or successful.

(a) Please refer to Tab (a) of Attachment 1 to this IR response.

(b) This information is not available. Installment Plan down payments cannot be easily differentiated from other payments. Although BC Hydro encourages call centre agents to negotiate a down payment from customers when setting up installment plans, this is not a requirement.

(c) Please refer to Tab (c) of Attachment 1 to this IR response.

(d) Please refer to tab (d) of Attachment 1 to this IR response. Due to data volume, the data extract was limited to calendar year 2014 and 2015.

(e) Please refer to Tab (e) of Attachment 1 to this IR response. Due to data volume, the data extract was limited to calendar year 2014 and 2015.

(f) Please refer to Tab (f) of Attachment 1 to this IR response.

(g) Please refer to Tab (g) of Attachment 1 to this IR response.

(h) Please refer to Tab (h) of Attachment 1 to this IR response.

(i) Please refer to Tab (i) of Attachment 1 to this IR response.

205.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.205.1 Please list all the programs and initiatives BC Hydro has undertaken since January 2010 to reduce the number of residential disconnections for nonpayment; if available, the metrics BC Hydro uses to determine if these programs are successful; and the results of any application of evaluation using those metrics.

RESPONSE:

BC Hydro has not undertaken any programs or initiatives aimed specifically at reducing the number of Residential disconnections for nonpayment. However, BC Hydro has offered a number of Residential DSM programs and other initiatives since January 2010 to enable Residential customers to reduce consumption and charges, and to better manage their electricity usage. These include:

- **The Residential DSM programs set out in Table 5-16 of Exhibit B-1;**
- **Low Income DSM programs:**
  - **ESK; and**
  - **ECAP.**
- **MyHydro customer portal:**
  - **Consumption graphs and downloads (using smart meter interval data); and**
  - **Consumption alerts.**
- **In-home Displays:**
  - **Real-time access to smart meter data and billing forecasts.**
- **First Nations Outreach:**
  - **Community visits for the purpose of informing First Nations government and community members of billing process and tools available to manage their consumption and accounts.**

With respect to metrics:

- **Evaluations of costs and energy savings are undertaken for all BC Hydro DSM programs; and**
- **The success of MyHydro tools is measured through metrics such as the number of accounts subscribed and the number of log-ins each month.**

206.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

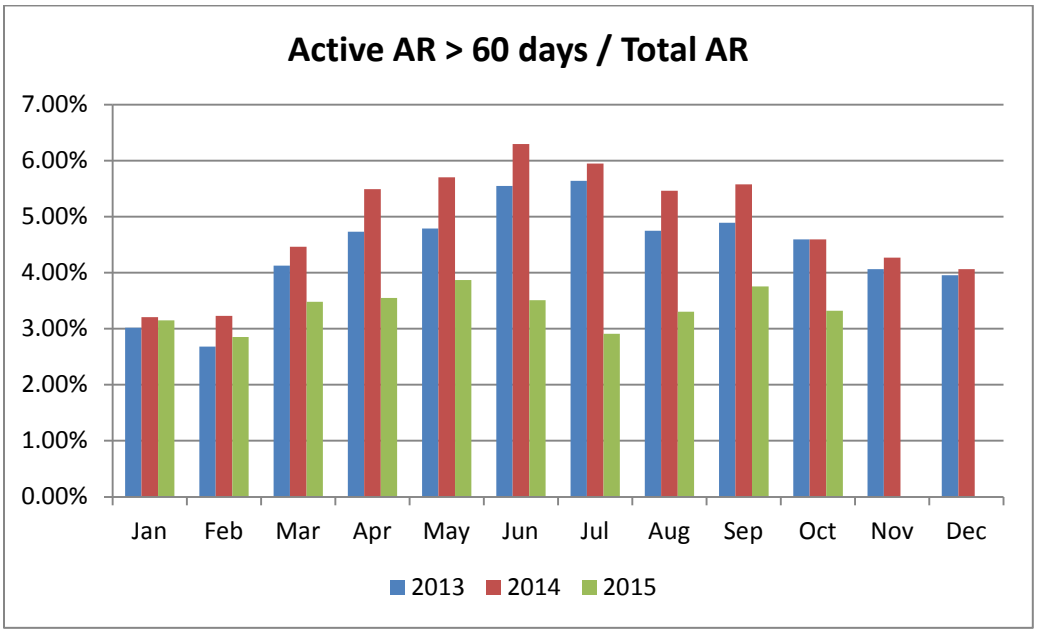
1.206.1 Please list all the programs and initiatives BC Hydro has undertaken since January 2010 to reduce the number of delinquent residential accounts; if available, the metrics BC Hydro uses to determine if these programs are successful; and the results of any application of evaluation using those metrics.

RESPONSE:

While the intent of the programs and initiatives listed in response to BCOAPO IR 1.205.1 was not necessarily to decrease the number of delinquent residential accounts, reducing consumption and increasing a customer's ability to manage his or her account would conceptually also reduce balances in arrears.

As noted in section 4.3 of Attachment 1 to the response to BCOAPO IR 1.192.1, Residential accounts receivables increased in F2013 and F2014. This has been attributed in part to the phased roll-out of RDR and the transition of field customer service to automated meter reading.

Starting in second quarter of F2015, a focussed effort was made to reduce aged accounts receivables (measured as Total Active A/R > 60 days as a percentage of Total A/R) by eliminating the backlog of accounts in arrears under operator review and ensuring that disconnection orders were completed in a timely manner. As shown in the chart below, this initiative resulted in a drop in Aged A/R starting in October 2014. Since that time, Aged A/R has been lower than in comparable months of prior years.



207.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.207.1 Of the residential accounts receiving a notice of an impending disconnection for nonpayment, for each month January 2012 to present inclusive, please provide:

(a) The total number of accounts that did not have their service disconnected by the date specified in the disconnect notice;
(b) The total number of accounts that did not have their service disconnected prior to the next bill received after receiving the notice of disconnection;
(c) The total number of accounts that did not have their service disconnected for nonpayment after receiving a disconnect notice for nonpayment that voluntarily terminated their accounts;
(d) The total number of accounts that did not have their service disconnected because the customer paid their bills in full prior to their scheduled disconnection;
(e) The total number of accounts that did not have their service disconnected because the customer paid their bills less than in full but sufficient to avoid their scheduled disconnection;
(f) The total number of accounts that did not have their service disconnected even though they retained an arrears that was sufficient large (or sufficiently old) to trigger a disconnection); and
(g) The total number of accounts on which account no payments were made prior to the issuance of the next bill after issuance of the disconnect notice.

RESPONSE:

(a) Not applicable. BC Hydro does not indicate a disconnection date in the disconnection notices.

(b) This information is not available.

(c) This information is not available.

(d) (e) BC Hydro cannot differentiate whether a disconnection was avoided due to full payments or partial payments. Please refer to Attachment 1 to this IR for a weekly report on the percentage of accounts for which customers made payments with 7 days of receiving the FNOD letters.

(f) This information is not available.

(g) This information is not available.

208.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.208.1 Please provide each customer segmentation study that has been prepared for BC Hydro of its residential customers since January 2010. If no such study has been prepared since January 2010, please provide the most recent study.

RESPONSE:

Please refer to Attachment 1 to this IR response for a 2014 segmentation study of low income customers.

Please also refer to the 2014 REUS, which is found at Appendix C-3F of Exhibit B-1.

LOW INCOME PROFILES

ELECTRICAL CONSUMPTION PATTERNS, DEMOGRAPHIC CHARACTERISTICS

TRACY XU & MATTHEW YIP

LOAD ANALYSIS

BC hydro FOR GENERATIONS

February 04, 2014

OUTLINE

- **Who are our low-income customers?**
  - Public data resource (Statistics Canada)
  - BC Hydro Residential End-use Survey (REUS)
- **How different are low-income customers compared to our residential population?**
  - BC Hydro Residential End-use Survey (REUS)
- **Low-income portraits for three data samples**
  - Energy Saving Kits (ESK)
  - Energy Conservation Assistant Program (ECAP)
  - Non-profit housing (NON-PROFIT)
- **Discussion**

KEY FINDINGS

- **Based on the 2011 Statistics Canada report, B.C. has the highest before-tax low-income rate (LICO) in Canada at 16% of population**
  - Seven highest risk groups: the unattached non-elderly, single parents, immigrants, activity limited, aboriginals, seniors, and children
- **BC Hydro 2012 REUS identified our low-income residential account rate at 11%**
  - More likely to be living in the Lower Mainland renting smaller, older homes and apartments
  - Mostly comprised of seniors, female, single parents, and/or less educated
  - Overall energy consumption is similar to those of the general residential population
- **ESK, ECAP, and Non-profit sample groups highlight different low-income attributes**
  - ESK is a non-verified income program. This self-reported low-income group shows the most similarity to the residential population
  - ECAP is a verified income program. Selected by BC Hydro, this group targeted on high consumption electrically heated Single Family Dwellings and Row Houses
  - Non-profit are customers subsidized by BC Housing or not for profit organizations. They are more likely to live in multi-unit residential building

KEY FINDINGS (CONT.)

- **Customer Call Center received 1.5 million calls in 2012 from 27% of residential customers and 14% customers called more than once**
  - 44% of ESK (2% of residential customers) contributed to 5% of total call volume
  - 48% of ECAP (0.2% of residential customers) contributed to 1% of total call volume
  - Only 194 calls were from Non-profit group
- **Top three concerns: payment, credit/collection, and account update**
  - ESK and ECAP calls were more likely to be about credit/collection
  - Non-profit group concerned more on maintenance and account updates
- **4% of total calls related to Power Smart programs**
  - 11% calls from ESK group
  - 5% calls from ECAP group
  - Only a couple of calls from Non-profit group related with ESK kits and appliance rebate

LOW INCOME RATE – STATISTICS CANADA

- Low-income cutoff (LICO) is determined by analyzing family expenditure data, below which family will devote 20% more of its income to the necessities than the average family would
- B.C. has the highest Low-income rates in the past decade in Canada

Table1: compare 10 years before-tax LICOs of B.C. province and Canada

% to population	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Canada	16%	16%	16%	15%	14%	14%	14%	13%	14%	13%
B.C.	21%	21%	19%	18%	17%	15%	15%	15%	16%	16%

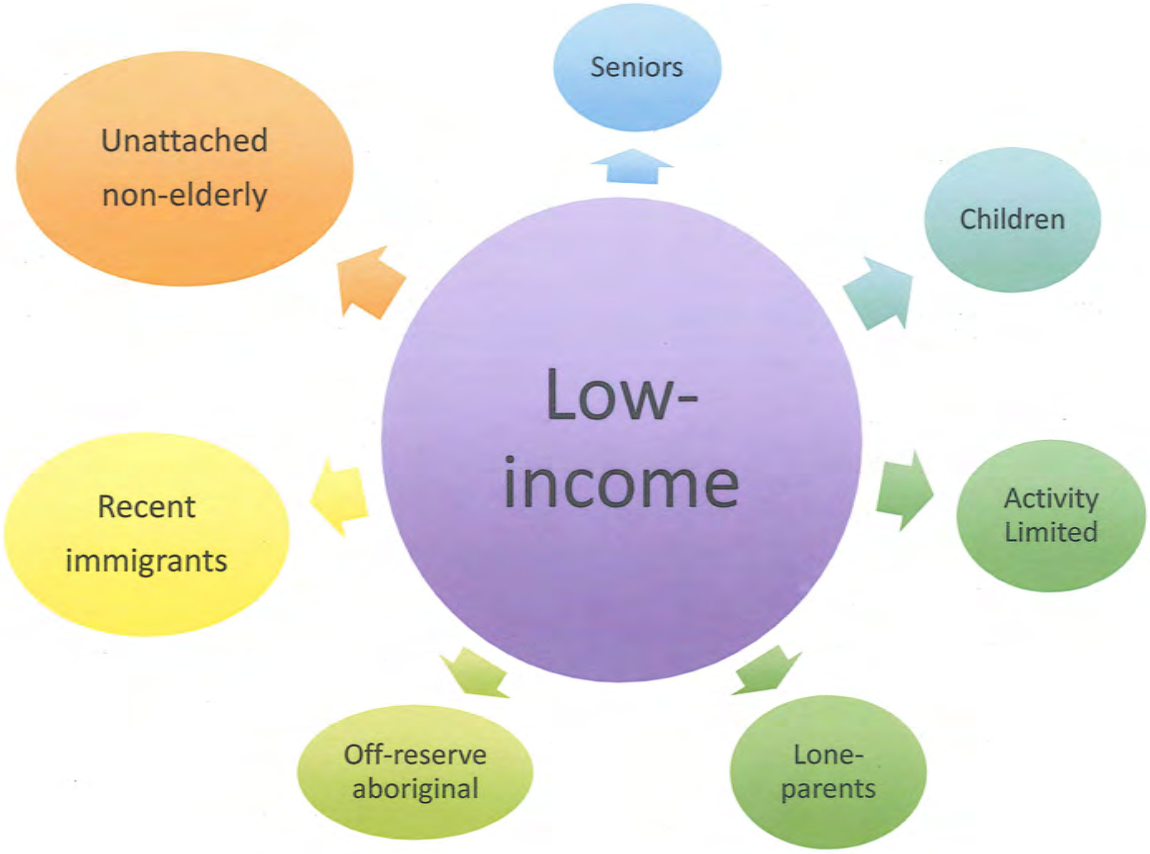
Table2: compare 10 years after-tax LICOs of B.C. province and Canada

% to population	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Canada	12%	12%	11%	11%	10%	9%	9%	10%	9%	9%
B.C.	16%	15%	14%	13%	13%	11%	11%	12%	12%	11%

LOAD ANALYSIS BC hydro FOR GENERATIONS

P6/P14

LOW INCOME AT RISK GROUPS



LOW INCOME RATE – BC HYDRO REUS 2012

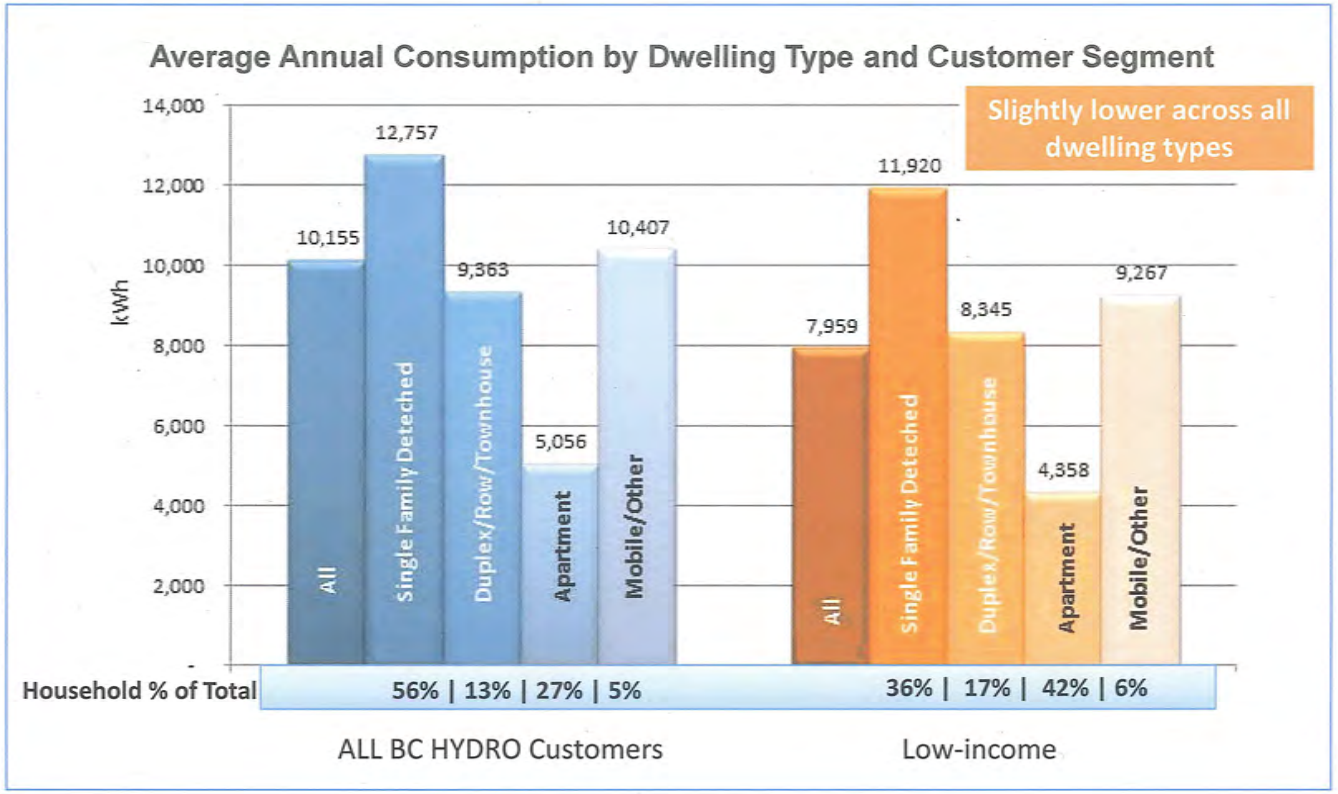
- BC Hydro Residential End-Use Survey (REUS) showed a 11% low-income rate in 2012 using before-tax LICO household income scale defined by Statistics Canada

Table3: 2009 LICO scale (pre-tax)

	Census Metropolitan Area (CMA)				
Household Occupants	Rural	<30,000	30,000 - 99,999	100,000 - 499,999	>500,000
1 person	$15,302	$17,409	$19,026	$19,144	$22,229
2 persons	$19,050	$21,672	$23,685	$23,832	$27,674
3 persons	$23,419	$26,643	$29,118	$29,299	$34,022
4 persons	$28,435	$32,349	$35,354	$35,573	$41,307
5 persons	$32,250	$36,690	$40,097	$40,345	$46,850
6 persons	$36,374	$41,380	$45,223	$45,504	$52,838
7 or more persons	$40,496	$46,071	$50,350	$50,661	$58,827

- REUS before-tax LICO is lower than the Statistics Canada value because
  - The REUS LICO is based on BC Hydro household accounts whereas the Statistics Canada LICO is based on individuals
  - Rental residents not having BC Hydro account will not be counted
- REUS shows similar LICO trends as Statistics Canada

REUS 2012 FINDINGS



REUS 2012 FINDINGS (CONT.)

	All BC Hydro Customers	Low-income Customers
Lower Mainland	57%	68%
Rental	18%	41%
Square footage		smaller
Number of people		more single or 3+
Female	47%	57%
Senior (65+)	31%	33%
Eduation less than grade 12	9%	17%
Non-English primary language	10%	28%

LOW-INCOME PORTRAITS

- **Participants of Energy Saving Kit (ESK) program**
  - Customers with greater awareness on low-income programs
  - Self-reported low-income (no verification)
- **Participants of Energy Conservation Assistance Program (ECAP)**
  - Customers struggled with high bill
  - Notice of Assessment (NOA) used for income verification
  - Customers experienced high energy consumption
- **Non-profit Housing Dwellers**
  - Customers in long-term low-income status
  - Income was verified by BC Housing or Charity associations

INVESTIGATIONS

- Dwelling type (LA)
- Heating code (LA)
- Average annual energy consumption (SAP/LA)
- Bill payment as a ratio of total household income (SAP/LA)
- Years of residency (SAP)
- Percentage of customers impacted by Residential Incline Block Tier2 pricing (SAP)
- Head of household age and gender (SAP)
- *Customer service transaction volume (SAP)*
- *BC Hydro customer credit rating (SAP)*
- *Top 10 Customer Call Center call reasons (CCS IVR)*
- *Square footage (BCA)*
- *Year of build (BCA)*

ESK/ECAP/NON-PROFIT FINDINGS

Categories	All BC Hydro Customers	ESK	ECAP	NON-PROFIT
kWh/Sqft. (Table A4)	Elec: 10kWh/Sqft Non-Elec: 7kWh/Sqft	Elec: 11kWh/Sqft Non-Elec: 7kWh/Sqft	Elec: 14kWh/Sqft ↑ Non-Elec: 9kWh/Sqft ↑	n/a
Year of Build (Table A9)	64% living in older buildings 19+ years	85% living in older buildings 19+ years	90% living in older buildings 19+ years	83% living in older buildings 19+ years
Impacted by RIB Tier2 Price (Table A5)	69% of All - 14% Elec SFD - 4% Elec Row - 33% NonElec SFD	66% of ESK ↓ - 18% Elec SFD - 6% Elec Row - 27% NonElec SFD	94% of ECAP ↑ - 22% Elec SFD - 24% Elec Row - 32% NonElec SFD	45% of Non-profit - 6% Elec SFD - 10% Elec Row - 13% NonElec SFD
Bill ($) as % of Household Income (Table A6)	Elec: 0.6%-2.5% Non-Elec: 0.4%~1.2%	Elec: 2%~8% Non-Elec: 1%~4%	Elec: 4%~10% Non-Elec: 3%~5%	Elec: 2%~8% Non-Elec: 1%~5%

ESK/ECAP/NON-PROFIT FINDINGS

Categories	All BC Hydro Customers	ESK	ECAP	NON-PROFIT
Top 3 call reasons (Table A10)	1. Bill payment 2. Credit 3. Account update	1. Credit 2. Bill payment 3. Maintenance	1. Credit 2. Bill payment 3. Maintenance	1. Maintenance 2. Business 3. Account update
Year of Residency (Table A8)	53% aged younger than 65, kept account active for less than 10 years	49% for the same category	51% for the same category	62% for the same category
Dwelling Type (Table A1)	57% SFD 27% Apartment 9% Row homes	50% SFD 30% Apartments 12% Row homes	57% SFDs 27% Row ↑	55% Apartments ↑ 16% Mobile 17% Row homes
Heating and Dwelling Types (Table A2)	63% Non-Elec - 42% SFD - 11% Apt. 37% Elec - 15% SFD - 17% Apt.	62% Non-Elec - 37% SFD - 13% Apt. 38% Elec - 13% SFD - 17% Apt.	44% Non-Elec - 35% SFD - 3% Apt. 56% Elec ↑ - 22% SFD - 24% Row homes	35% Non-Elec - 9% SFD - 17% Apt. 65% Elec - 3% SFD - 48% Apt. ↑

DISCUSSIONS

APPENDIX A: ESK/ECAP/NONPROFIT

DWELLING TYPE

- About 40% of ECAP participants also participated in the ESK program
- 13% of ECAP participants are living in non-profit subsidized houses
- ESK participants are likely to be living in multiple units dwellings
- ECAP participants are more likely to be living in Row Houses and Single/Duplex homes
- Apartment units make up more than half of all Non-profit subsidized homes (55% High-rise and Low-rise combined vs. 28% of all customers)

Table A1: Dwelling Type and Customer Segment

Dwelling Type	ALL BC HYDRO CUSTOMERS	ESK	ECAP	Non-profit
Total Population	1,633,854	64,832	7,954	4,847
High-Rise Apt	24%	25%	7%	39%
Low-Rise Apt	4%	5%	3%	16%
Mobile/Others	6%	9%	6%	16%
Row House	9%	12%	27%	17%
Single/Duplex	57%	50%	57%	12%

HEATING AND DWELLING TYPES

- ESK participants closely mirror the general population both in dwelling type distribution and in Electric/Non-Electric heated homes splits
- ECAP participants are more likely to be living in Electric heated Row and Single/Duplex homes (46% of low-income vs. 19% of population)
- Non-profit housing is comprised of more multi-unit Electric heated dwellings than the general population (62% of low-income vs. 23% of population)

Table A2: Dwelling Type , Heating Type, and Customer Segment

Dwelling Type	ALL BC HYDRO CUSTOMERS		ESK		ECAP		Non-profit	
	ELEC	NON-ELEC	ELEC	NON-ELEC	ELEC	NON-ELEC	ELEC	NON-ELEC
Total (% to populatio	37%	63%	38%	62%	56%	44%	65%	35%
High-Rise Apt	15%	9%	14%	11%	5%	2%	27%	12%
Low-Rise Apt	2%	2%	3%	2%	2%	1%	11%	5%
Mobile/Others	2%	5%	3%	6%	3%	3%	14%	2%
Row House	5%	5%	6%	6%	24%	3%	10%	7%
Single/Duplex	15%	42%	13%	37%	22%	35%	3%	9%

ENERGY CONSUMPTION

Table A3: Average Annual Consumption (kWh) by Dwelling Type

Average Annual kWh	ALL BC HYDRO CUST.		ESK		ECAP		Non-profit	
	ELEC	NON-ELEC	ELEC	NON-ELEC	ELEC	NON-ELEC	ELEC	NON-ELEC
All Dwelling Type	13,040	8,636	11,906	7,663	16,880	12,182	6,722	6,715
High-Rise Apt	5,524	3,221	5,611	3,322	9,528	10,342	4,276	2,482*
Low-Rise Apt	7,274	5,008	6,840	4,829	12,274	11,779	5,068	3,844*
Mobile/Others	17,093	7,947	14,775	8,858	16,783	11,080	11,237	12,149*
Row House	11,654	6,738	11,326	6,117	13,261	8,080	13,906	6,136
Single/Duplex	21,417	10,258	19,593	9,188	22,907	12,773	19,623	13,256

* Data contains high consumption for single meter buildings

Table A4: Average Annual kWh per Square Footage by Dwelling Type

Average kWh/per Sqft	ALL BC HYDRO CUST.		ESK		ECAP		Non-profit	
	ELEC	NON-ELEC	ELEC	NON-ELEC	ELEC	NON-ELEC	ELEC	NON-ELEC
All Dwelling Type	10	7	11	7	14	9	9	8
High-Rise Apt	6	4	6	4	9	6	7	1
Low-Rise Apt	7	5	7	6	13	8	8	2
Mobile/Others	15	8	16	10	18	12	5	3
Row House	8	4	8	4	8	6	6	4
Single/Duplex	14	7	14	7	15	9	13	9

TIER2 PRICING IMPACT

- In general, about 70% of residential customers had at least one bill in 2012 with a Tier2 charge
- 66% of ESK participants, 94% of ECAP participants, and 51% of Non-profit housing units were impacted by Tier2 pricing

Table A5: Percentage of Customers Impacted by RIB Tier2 Pricing

Dwelling Type (Impacted by Tier2)	ALL BC HYDRO CUSTOMERS		ESK		ECAP		Non-profit	
	ELEC	NON-ELEC	ELEC	NON-ELEC	ELEC	NON-ELEC	ELEC	NON-ELEC
Total (% to population)	69%		66%		94%		45%	
Total (% to population)	29%	40%	30%	36%	55%	39%	25%	20%
High-Rise Apt	7%	1%	7%	1%	4%	2%	12%	2%
Low-Rise Apt	1%	0%	2%	1%	2%	1%	3%	1%
Mobile/Others	2%	3%	3%	4%	3%	3%	1%	1%
Row House	4%	2%	6%	2%	24%	2%	10%	3%
Single/Duplex	14%	33%	13%	27%	22%	32%	6%	13%

HYDRO BILL AS A PERCENTAGE OF INCOME

Table A6: Hydro Bill as a Percentage of Household Income

Percentage of Hydro Bill vs. Household Income	ALL BC HYDRO CUST.		ESK		ECAP		Non-profit	
	ELEC	NON-ELEC	ELEC	NON-ELEC	ELEC	NON-ELEC	ELEC	NON-ELEC
All Dwelling Type	1.5%	1.0%	4.8%	3.0%	6.9%	4.8%	2.7%	2.7%
High-Rise Apt	0.6%	0.4%	2.2%	1.3%	3.7%	4.1%	1.6%	1.0%
Low-Rise Apt	0.8%	0.6%	2.6%	1.9%	4.6%	4.6%	1.9%	1.5%
Mobile/Others	1.9%	0.9%	6.0%	3.4%	6.7%	4.4%	4.9%	4.9%
Row House	1.3%	0.7%	4.5%	2.3%	5.3%	3.1%	5.7%	2.4%
Single/Duplex	2.5%	1.2%	8.1%	3.5%	9.6%	5.1%	8.2%	5.4%

- For the general residential population, we assumed an average household before-tax income of $74,448 (Stats Can 2011)
- For ESK/ECAP/NON-PROFIT groups, we assumed an household income of a full-time minimum wage worker ($10.25/hr or $21,320/year)

CUSTOMER AGE AND GENDER

Table A7: Gender and Age

Gender	Age Group	All BC Hydro Customers	ESK	ECAP	Non-profit
Female	0 <= age <= 30	4%	4%	5%	0%
	30 < age <= 40	9%	9%	15%	23%
	40 < age <= 50	10%	10%	16%	17%
	50 < age <= 60	10%	11%	13%	14%
	60 < age <= 65	4%	5%	5%	6%
	age > 65	9%	15%	10%	6%
Male	0 <= age <= 30	4%	3%	2%	3%
	30 < age <= 40	10%	6%	5%	11%
	40 < age <= 50	11%	8%	9%	6%
	50 < age <= 60	12%	9%	9%	3%
	60 < age <= 65	5%	4%	4%	3%
	age > 65	12%	15%	8%	9%
	Data Coverage	64%	64%	59%	1%

YEAR OF RESIDENCY

Table A8: Number of Active Years in BC HYDRO Billing System

Age Group	Years of Residency	All BC Hydro Customers	ESK	ECAP	Non-profit
Junior (Age < 65)	<= 5	35%	34%	30%	28%
	6 - 10	18%	15%	21%	34%
	11 - 15	9%	7%	11%	8%
	16 - 20	7%	5%	8%	9%
	21 - 25	5%	3%	8%	13%
	26 - 30	2%	1%	3%	4%
	31 - 35	1%	1%	1%	3%
	36 - 40	1%	0%	0%	0%
	> 40	1%	0%	0%	0%
Senior (Age >= 65)	<= 5	5%	7%	3%	0%
	6 - 10	5%	7%	4%	0%
	11 - 15	3%	5%	3%	0%
	16 - 20	2%	3%	2%	0%
	21 - 25	2%	4%	3%	0%
	26 - 30	1%	2%	2%	2%
	31 - 35	1%	1%	1%	1%
	36 - 40	1%	1%	1%	1%
	> 40	1%	2%	1%	1%

YEAR OF BUILD

Table A9: Dwelling Heating Type versus Year of Build

Heating Type	Year of Build	All BC Hydro Customers	ESK	ECAP	Non-profit
NON-ELEC	Before 1950	6%	7%	5%	4%
	1950-1975	20%	24%	20%	16%
	1976-1985	10%	12%	11%	10%
	1986-1995	12%	13%	13%	21%
	1996-2005	9%	7%	4%	7%
	After 2005	5%	2%	1%	2%
ELEC	Before 1950	2%	3%	5%	7%
	1950-1975	6%	8%	12%	8%
	1976-1985	7%	9%	11%	9%
	1986-1995	9%	9%	11%	8%
	1996-2005	6%	4%	3%	4%
	After 2005	6%	3%	2%	5%

SAP CUSTOMER TRANSACTIONS

Table A10: Customer service request

Type	Percent
Telephone	66%
System Generated	16%
Missing	10%
Internet	6%
E-mail	1%
Letter	1%
Fax number	0%
Personal	0%

CUSTOMER CALLS (IVR)

- 27% of customers called at least once during year 2012 on an annual call volume of 1.5 million
- 42% of the ESK/ECAP/NONPROFIT groups called at least once during year 2012 generating 46,000 total calls

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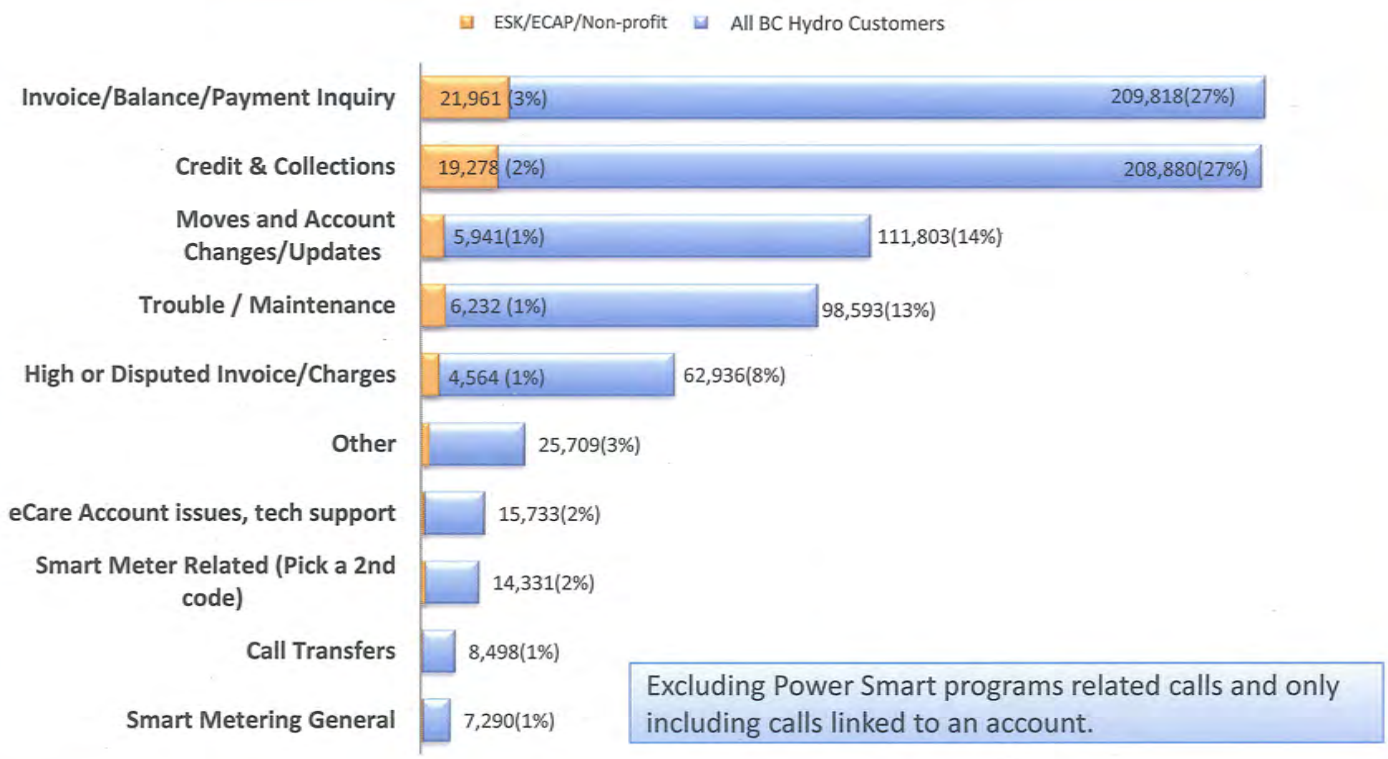
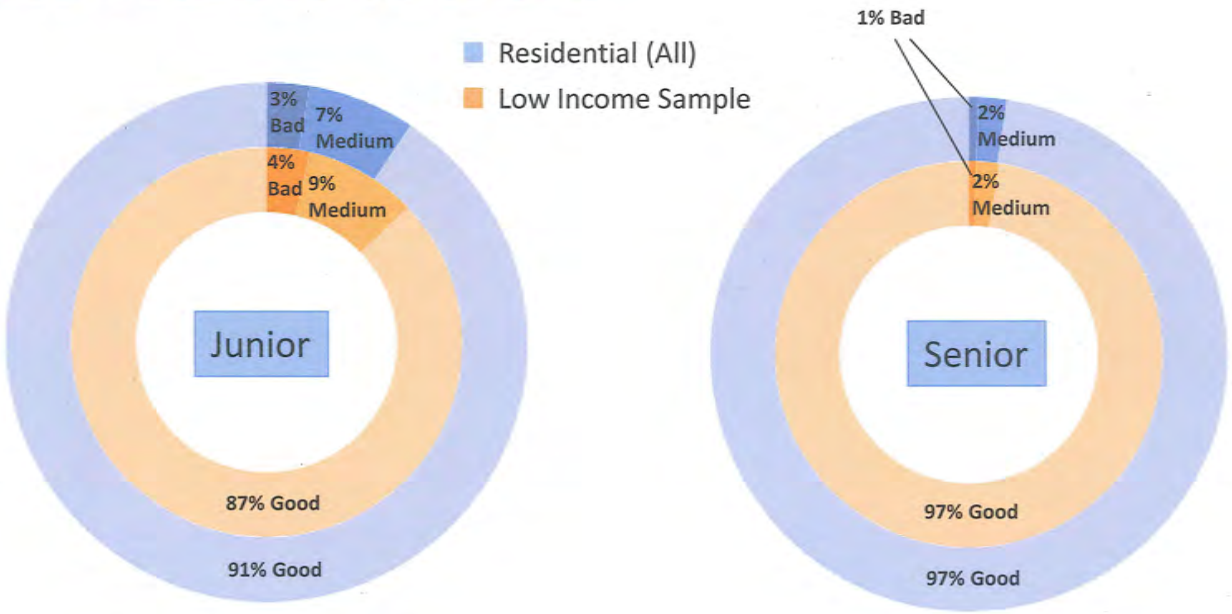
A11/A32

Calls Volumes by Call Reasons



Excluding Power Smart programs related calls and only including calls linked to an account.

BCH CREDIT RATING



- "Junior" (under age 65) low income sample group has more credit issues than the "Junior" residential population
- "Senior" (age 65+) low income sample group showed no difference compared to the "Senior" residential population

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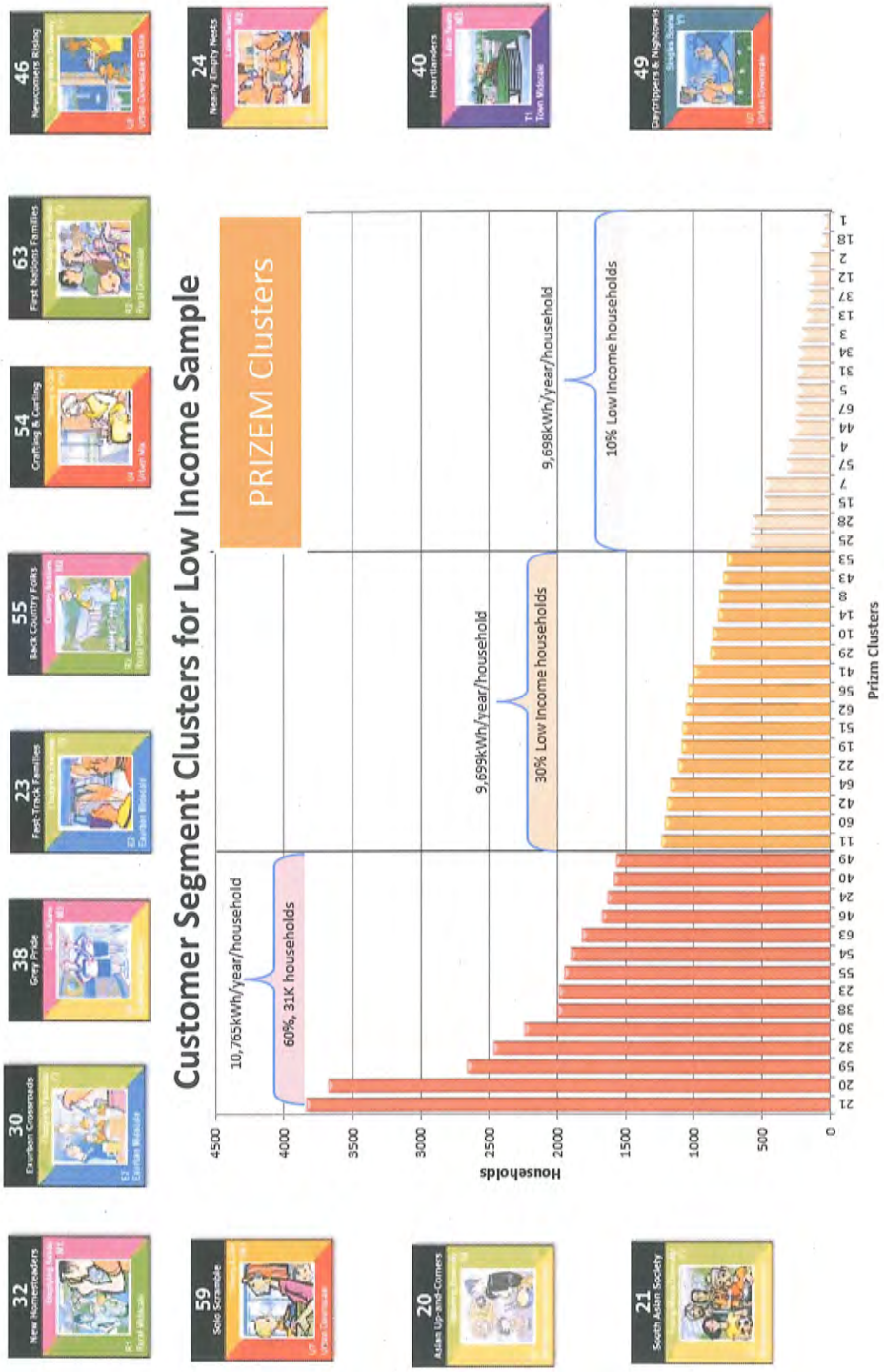

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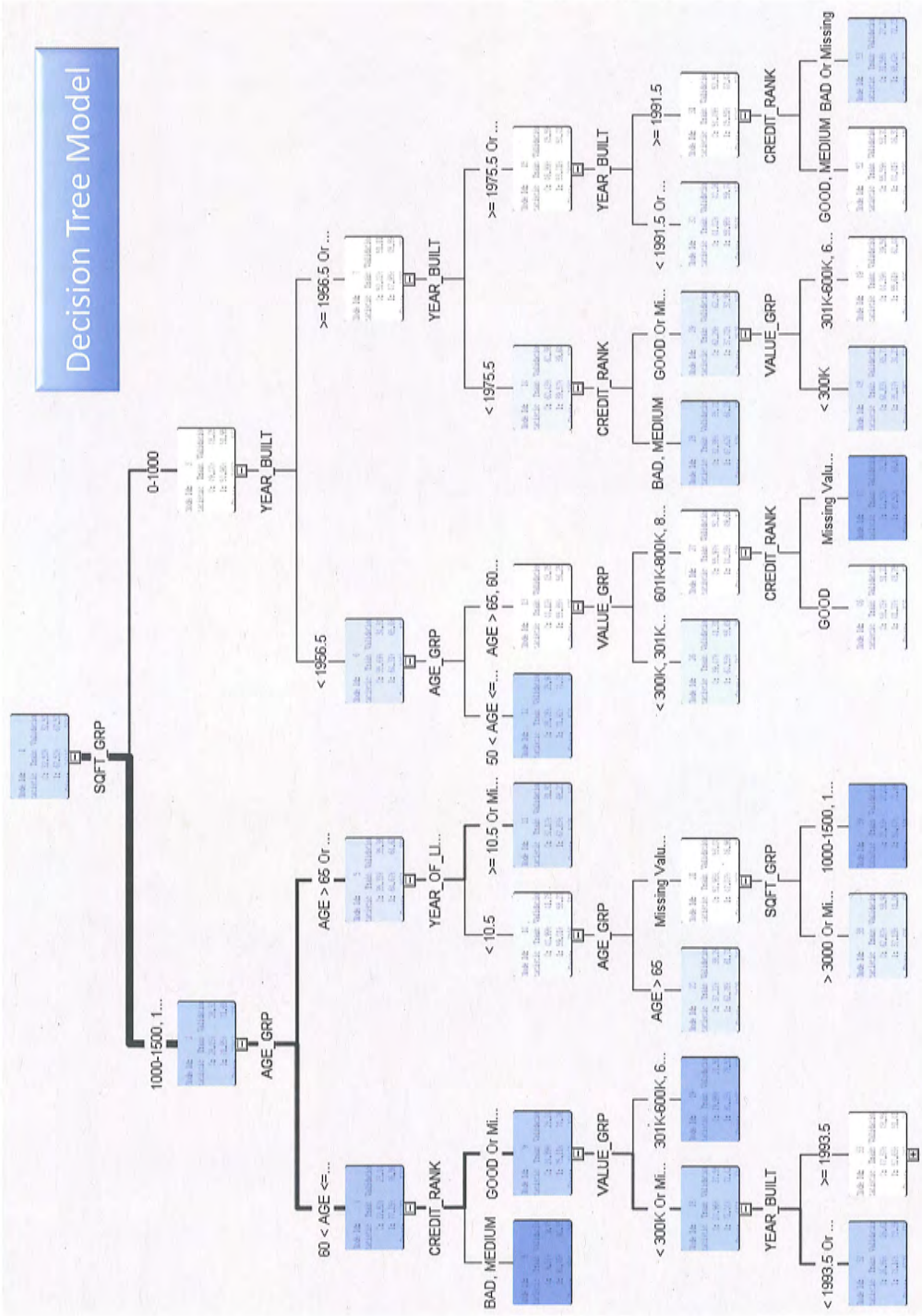
Decision Tree Model



APPENDIX B: RESIDENTIAL END-USE SURVEY 2012 TABLES

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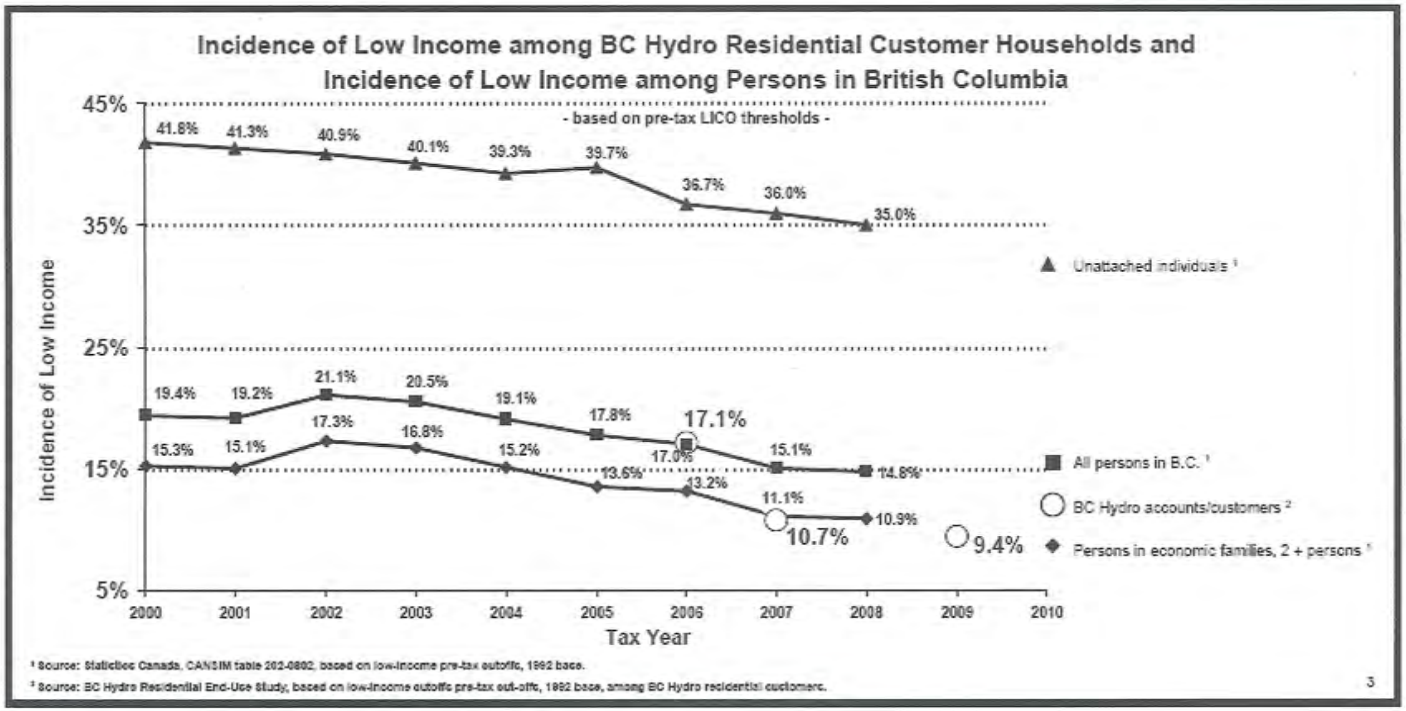
Similar trend lines between BC Hydro and Statistics Canada before-tax LICOs



(Reference 4)

Table B1: Regional Distribution of Low-income Households in B.C.

Regional Distribution of Households	All BC Hydro Residential Customers	Non-LICO sub-population	Low-income (LICO) sub-population
Total Number of Accounts	1,637,000	1,455,000	182,000
Lower Mainland	58%	57%	68%
Vancouver Island	22%	22%	17%
Southern Interior	12%	12%	8%
North	9%	9%	7%

Table B2: Status of Home Ownership in BC's Low-income Population

Home Ownership	All BC Hydro Customers	Low-income (LICO) sub-population	Low-income (Elect Heat)	Low-income (non - EH)
Total Households (N)	1,637,000	182,000	79,000	103,000
Owned	81. %	57%	51%	63%
Rented	18%	41%	47%	36%
Co-op	1%	2%	2%	1%

Table B3: Dwelling Types by Customer Segment

Dwelling Type (% of population)	All BC Hydro Customers	Low-income (All)	Low-income (Elect Heat)	Low-income (non-EH)
Total (N)	1,637,000	182,000	79,000	103,000
Single Family Detached	56%	36%	21%	48%
Duplex/Row/Townhouse	13%	17%	21%	14%
Apartment/Condo	27%	42%	55%	32%
Mobile/other	5%	6%	4%	7%

(Reference 2 & 6)

Table B4: Household Composition of BC's Low-income Population

Number of Household Occupants and Presence of Children and Young Adults	All BC Hydro Customers	Low-income (LICO) sub-population
Total (N) – Number of Occupants	1,637,000	182,000
1	25%	32%
2	42%	27%
3	13%	10%
4+	21%	31%
Household with children under 12	17%	27%
Household with young adults (13-24)	20%	27%
Total %	100%	100%

Table B5: Age and Sex of Low-income Primary Household Bill Payers

Primary Household Bill Payers	All BC Hydro Customers	Low-income (LICO) sub-population
Total (N)	1,637,000	182,000
Female	47%	57%
Male	53%	43%
Young Adult (18-24)	1%	3%
Senior (65+)	31%	33%

(Reference 2 & 6)

Table B6: Education Level of BC's Low-Income Sub-population

Level of Education Reached (% of population)	All BC Hydro Customers	Low-income (LICO) sub-population
Total (N)	1,637,000	182,000
Less than grade 12	9%	17%
High School Diploma	15%	15%
Some college, vocational or technical school	19%	20%
College, vocational or technical school	20%	12%
Some university	7%	8%
University / graduate degree	31%	28%

Table B7: Language Spoken at Home in B.C. Households

Language Spoken at Home (Home Language of Primary Household Maintainer)	All BC Households	Low-income (LICO) sub-population
Total (N)	1,637,000	182,000
English	90%	72%
French	0.5%	1.4%
Cantonese	3%	8%
Mandarin	2%	6%
Punjabi	0.3%	1.4%
Other language	4.4%	11%

(Reference 2 & 6)

Table B8: Annual consumption by Dwelling Type and Customer Segment

Average Annual Consumption (kWh) by Dwelling Type	All BC Hydro Customers	Low-income (all)	Low-income (Elect Heat)	Low-income (non-EH)
Total (N)	1,637,000	182,000	79,000	103,000
All Types	10,155	7,959	8,962	7,115
Single Family Detached	12,757	11,920	18,586	9,629
Duplex/Row/Townhouse	9,363	8,345	8,791	7,700
Apartment or condo	5,056	4,358	5,344	2,971
Mobile/other	10,407	9,267	11,236	8,095

Table B9: Impact of rates on Low-Income and Non Low-Income Customers

	Low-Income (Electric Heat) Households		Non-Low-Income Households	
	Customer A (Townhouse)	Customer B (Single Detached)	Customer C (Townhouse)	Customer D (Single Detached)
Current annual bill (at 8.27 ¢/kWh blended rate)	$744	$1,489	$744	$1,489
Average monthly bill in peak season (Feb)	$78	$170	$78	$170
Annual bill after fictional rate increase (10%/yr over 3 yrs ~ 9.54, 10.50, 11.55 ¢/kWh)	$991	$1,984	$991	$1,984
Absolute bill increase (after 3 years)	$247	$495	$247	$495
Electricity bill as % of income before rate increase	3%	5%	1%	2.5%
Electricity bill as % of income after increase	3%	7%	1.7%	3%
Monthly bill (peak season) as % of income after rate increase	4%	9%	2%	4.5%

(Reference 2 & 6)

APPENDIX C: STATISTICS CANADA FIGURES

Note: Based on after-tax LICOs. The category "Large urban areas" includes the 20 largest Census Metropolitan Areas (CMAs). For the list of areas included in the category 'Large urban areas', see large urban areas. The category 'Other areas' includes all other urban areas as well as the rural communities in Canada.

Source: Statistics Canada. *Table 202-0802 - Persons in low income families, annual,* CANSIM (database).

[Show Data Table]

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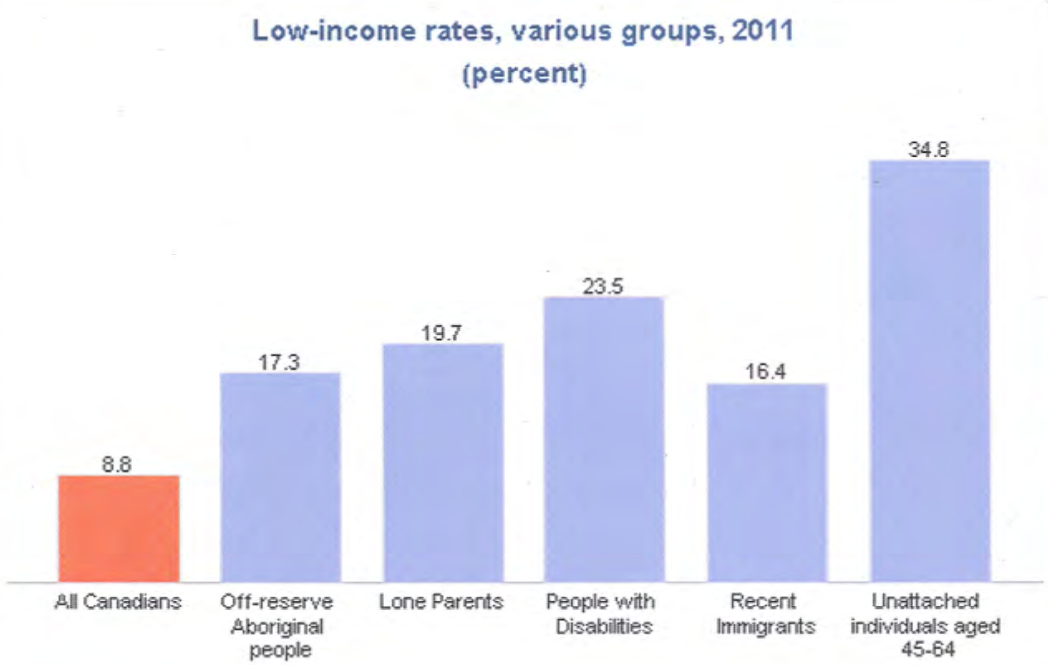

Note: Based on after-tax LICOs.

Source: Statistics Canada calculations based on Statistics Canada. *Survey of Labour and Income Dynamics*. Ottawa: Statistics Canada, 2013.

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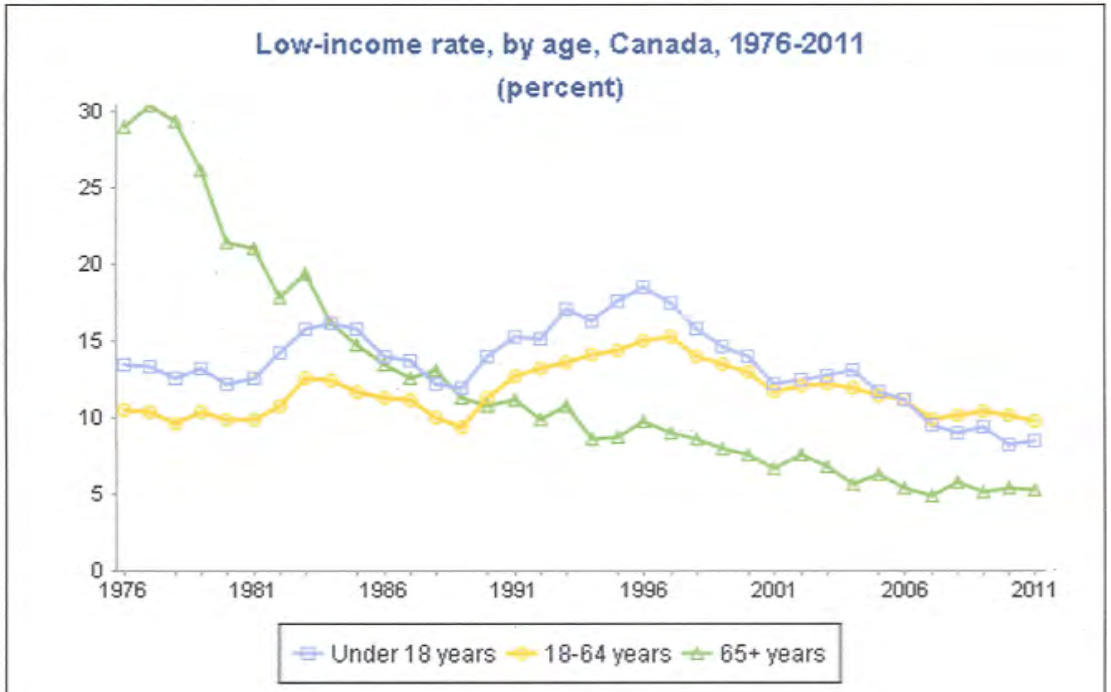

Note: Based on after-tax LICOs.

Source: Statistics Canada. *Table 202-0802 - Persons in low income families, annual,* CANSIM (database).

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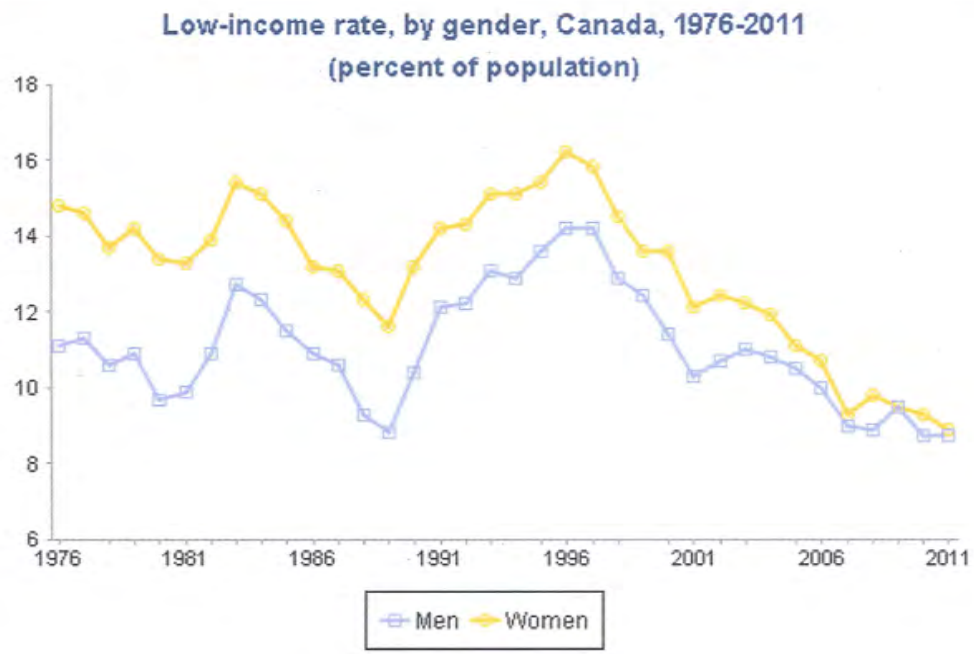

Note: Based on after-tax LICOs.

Source: Statistics Canada. *Table 202-0802 - Persons in low income families, annual,* CANSIM (database).

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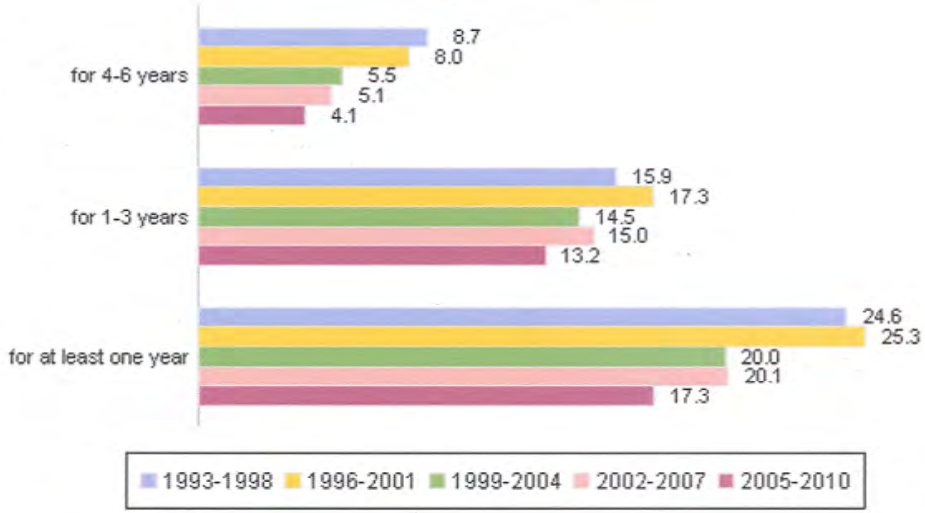
Canadians with low income over 6-year periods, 1993-1998, 1996-2001, 1999-2004, 2002-2007 and 2005-2010

(percent)



Note: 1. Years spent in low income are not necessarily consecutive.
2. Based on after-tax LICOs.

Source: HRSDC calculations based on Statistics Canada. *Persistence of low income, by selected characteristics, every 3 years* (CANSIM Table 202-0807). Ottawa: Statistics Canada, 2012.

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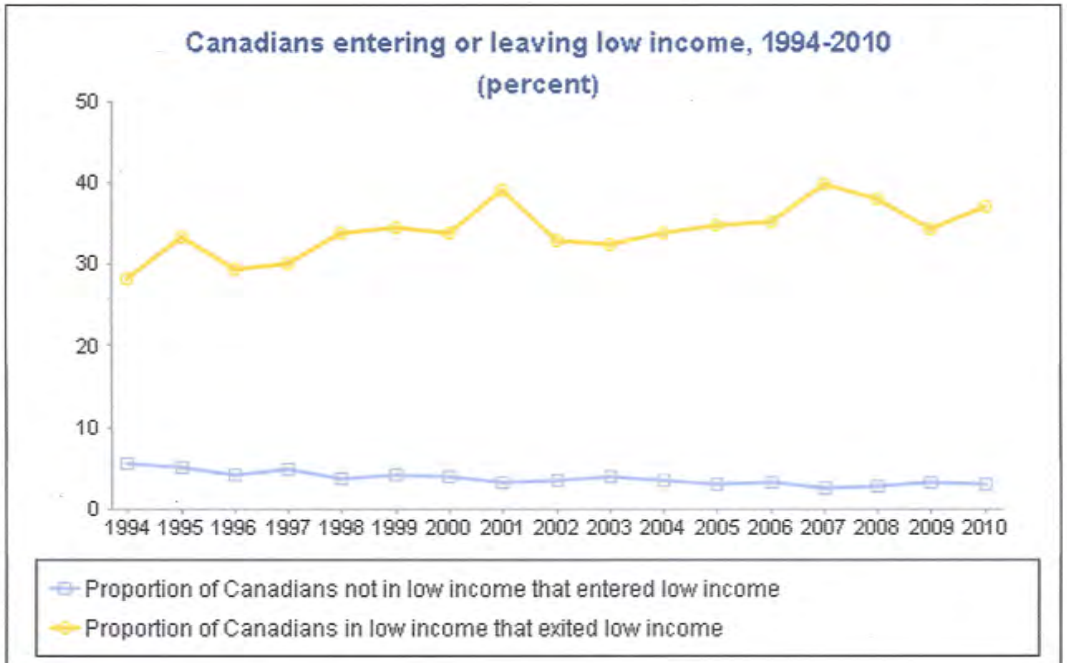

Note: Based on after-tax LICOs.

Source: HRSDC calculations based on Statistics Canada. *Transitions of persons into and out of low income before and after tax, by selected characteristics, annual* (CANSIM Table 202-0806). Ottawa: Statistics Canada, 2012.

[Show Data Table]

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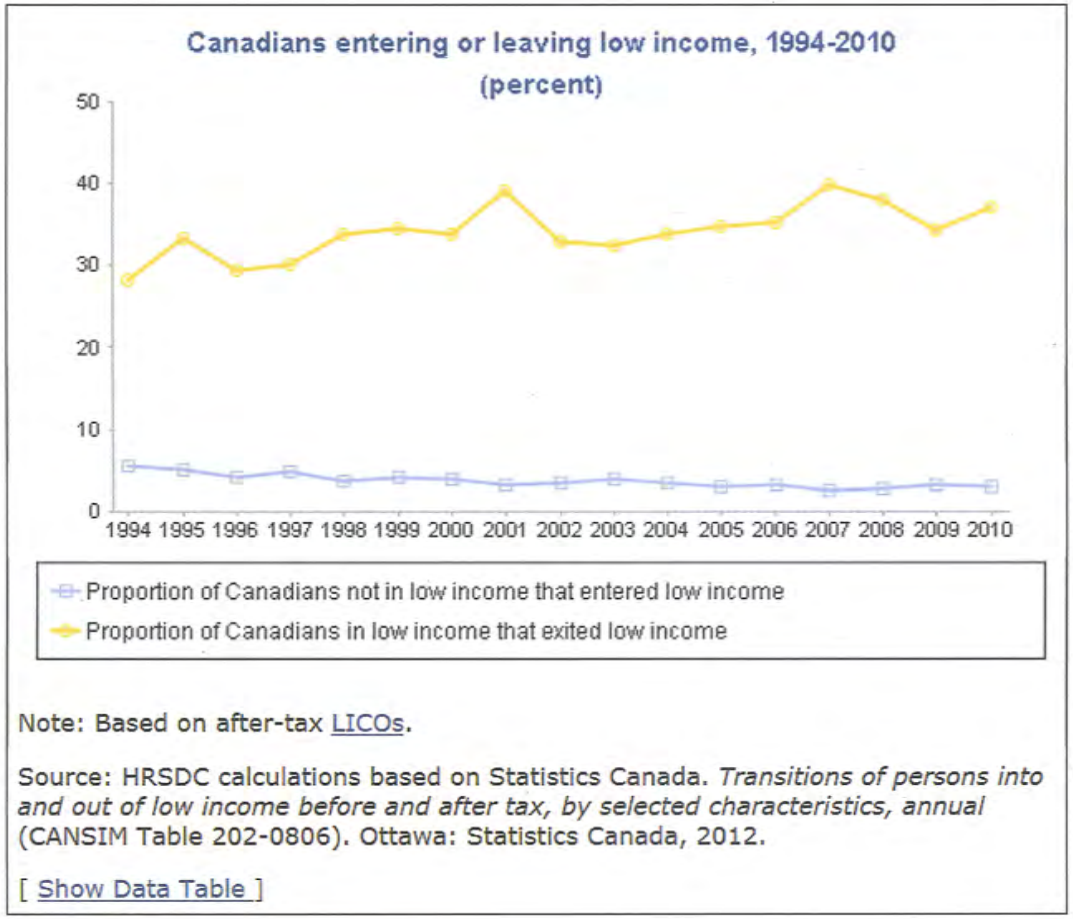


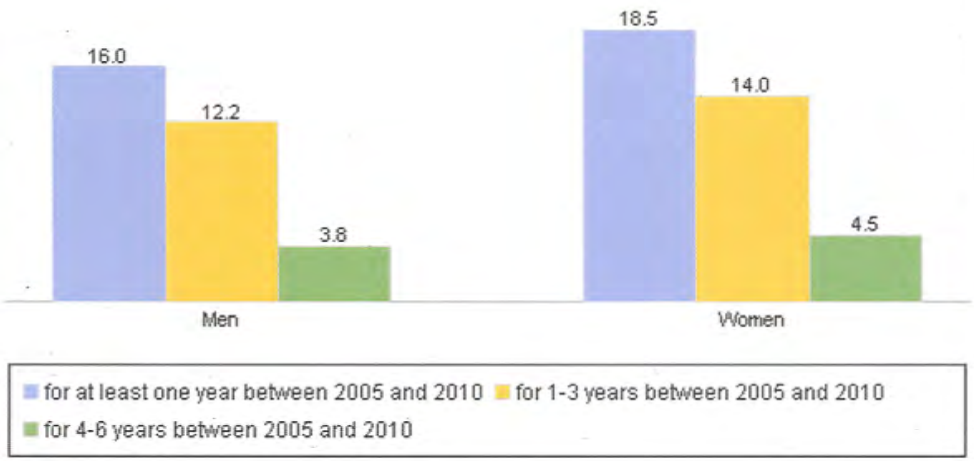
Note: Based on after-tax LICOs.

Source: HRSDC calculations based on Statistics Canada. *Transitions of persons into and out of low income before and after tax, by selected characteristics, annual* (CANSIM Table 202-0806). Ottawa: Statistics Canada, 2012.

[Show Data Table]

(http://www4.hrsdc.gc.ca/.3ndic.1t.4r@-eng.jsp?iid=23)

Canadians with low income over a 6-year period, by gender, 2005-2010 (percent)



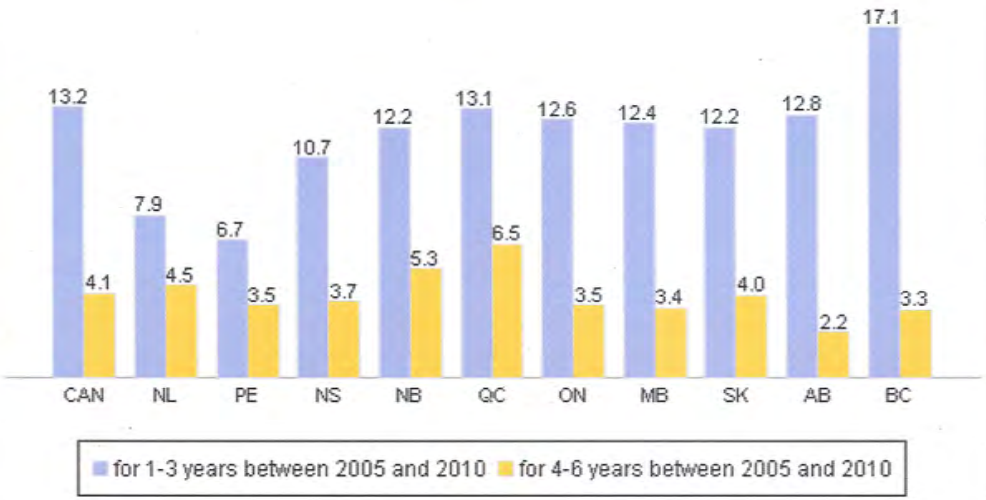
Note: 1. Years spent in low income are not necessarily consecutive.
2. Based on after-tax LICOs.

Source: HRSDC calculations based on Statistics Canada. *Persistence of low income, by selected characteristics, every 3 years* (CANSIM Table 202-0807). Ottawa: Statistics Canada, 2012.

[Show Data Table]

(http://www4.hrsdc.gc.ca/.3ndic.1t.4r@-eng.jsp?iid=23)

Canadians with low income over a 6-year period, by region, 2005-2010 (percent)



Note: 1. Years spent in low income are not necessarily consecutive.
2. Based on after-tax LICOs.

Source: HRSDC calculations based on Statistics Canada. *Persistence of low income, by selected characteristics, every 3 years* (CANSIM Table 202-0807). Ottawa: Statistics Canada, 2012.

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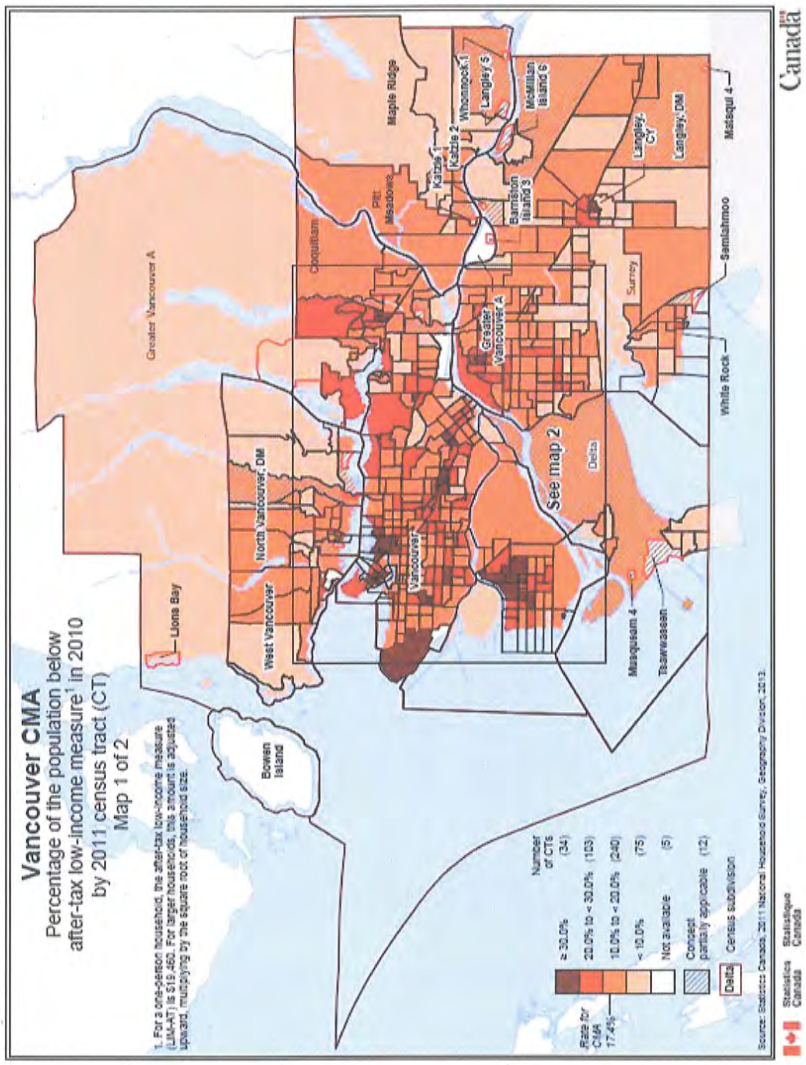

(http://www12.statcan.gc.ca/nhs-enm/2011/as-sa/map-carte/pdf/2011-99014-006-933-013-05-00-eng.pdf)

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11. Canadian Center for Policy Alternatives (2010), *A Closer Look at Low Wages in BC* (http://www.policyalternatives.ca/sites/default/files/uploads/publications/reports/docs/ccpabc_closer_look_low_wages_0.pdf)

209.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.209.1 Please provide a copy of all written documents, of any nature, including tariffs, staff training manuals and staff "procedures" manuals, that describe and explain the circumstances under which:

(a) Termination of service *is* appropriate as well as the circumstances under which termination of service is *not* appropriate;
(b) It is appropriate and/or inappropriate to negotiate deferred payment plans
(c) A cash security deposit is required of: (i) a new customer; and (ii) an existing customer;
(d) It is appropriate and/or inappropriate to place residential customers on a levelized monthly (or budget) billing plan;
(e) BC Hydro will turn a residential account over to a third party collection agency for collection.

RESPONSE:

Please refer to Attachment 1 to this IR response for extracts of online staff procedures relating to the above requests.

Sections of the existing Electric Tariff related to these items are as follows:

(a) Termination of Service

2.3 Refusal to Provide Service and Discontinuance of Service;

6.7 Service Reconnection Charge;

7.2.3 Failure to Comply with Power Factor Requirements;

7.3 Disturbing Use;

9.5 Access to Premises;

9.6 Curtailment of Service;

9.7 Liability of BC Hydro;

RS 1105 Special Condition 6;

RS 1205, 1206, 1207 Special Condition 8; and

RS 1401 Special Condition 2.

(b) Deferred Payment Plans

5.8 Back-Billing

Note there are no additional references related to Installment Plans for arrears unrelated to back-billing.

(c) Security Deposits

2.4.2 Security Deposits for Applicants; and

2.4.3 Security Deposits for New Customers.

(d) Levelized Monthly Billing

2.4.1 Pay As You Go Billing; and

5.6 Monthly Equal Payment.

(e) Referral to a Collections Agency

No references.

Note that BC Hydro will be filing its proposed revision to its Electric Tariff on December 22, 2015.

The following is an extract of staff procedural manuals that outline the business rules for active accounts related to the identified topics.

(a) Termination of service is appropriate as well as the circumstances under which termination of service is not appropriate;

If a new customer applies for service, the existing customer will automatically have their account closed (called a Forced Move Out – FMO). If a customer contacts BC Hydro and provides at least 24 hrs notice it is appropriate to terminate service.

BC Hydro will terminate service on single accounts that have been disconnected for 30 days or more by closing the account. Process is below.

Disconnected Customers with Single Account

Closing the Account

When a customer has a single account that has been disconnected for 30 days or more:

- Check the scheduled meter reading for consumption
- If there is no scheduled meter reading or there is a scheduled meter reading within two weeks of the disconnection, request a 'Control' reading (AMCG status '2' or '3')
- Hold the account or premise in your Business Workplace and confirm if the reading indicates zero consumption
- For Irrigation accounts, refer to Disconnected Irrigation Accounts

If the meter reading indicates zero consumption:

- If the account has **not billed** since the disconnection date:
    - Create Move Out using the disconnection date

  If the account has billed since the disconnection date:
    - Create Move Out for either one day after the last billed reading or one day after the last invoice date

  If the customer **is the owner** of the property:
    - Create a Contact and Premise Notes: CLOSED BY CREDIT-DISCONNECTED CUSTOMER IS R/O-DO NOT ACCEPT MOVE IN UNLESS PURCHASE AGREEMENT RECEIVED

  If the customer is the owner of the property and there is a Power Smart Home Loan balance owing, the Credit Admin agent will:

- Create a Contact and Premise Notes: CLOSED BY CREDIT-DISCONNECTED CUSTOMER IS R/O–POWER SMART HOME LOAN BALANCE $/DO NOT ACCEPT MOVE IN/REFER CALLS TO 72494

If the customer **is not the owner** of the property:

- Create a Contact **and** Premise Notes: CLOSED BY CREDIT-DO NOT ACCEPT MOVE IN UNLESS RENTAL AGREEMENT RECEIVED

If the disconnected customer states they plan to pay the invoice for reconnection, follow up after the proposed payment date:

- If the payment is not received, close the account based on the above guidelines

It is inappropriate to terminate service when less than 24 hrs notice has been provided or when the previous account holder is in arrears and there is reason to believe that the previous account holder is still residing at the premise.

(b) It is appropriate and/or inappropriate to negotiate deferred payment plans

Process of how agent determines appropriate Installment Plan is below:

When a **customer does not offer any date** for payment of a Past Due amount:

- Attempt to obtain **full** payment of Past Due balance within **two business days** from the date of the call
- If the customer is unable to pay the full Past Due amount within the two business days from the date of the call, attempt to obtain full payment of the Past Due balance within **two weeks** from the date of the call
- If the customer is still unable to pay the full Past Due amount within two weeks from the date of the call, attempt to obtain full payment before the next billing date

When a **customer offers a date within two weeks** for payment of a Past Due amount:

- Agree to the customer's offered payment arrangement. It is not required to negotiate a payment within two business days

When a **customer offers a date outside of two weeks** for payment of a Past Due amount:

- Attempt to obtain a **portion** (good starting point is 50 per cent) of Past Due balance within **two business days** from the date of the call
- For the balance, attempt to make payment arrangements before the customer's next billing date. As a last resort, payment arrangements may be made up to a **maximum** of three months from the date of the customer's request

For more information, refer to:

- Credit Call Handling
- Payment Negotiations

- Best Practice Techniques – Credit

The **maximum** length for payment arrangements on an Installment Plan for a Past Due balance is three months from the date of the customer's request. This should only be offered as a last resort.

Avoid using words or tone that suggests another person (Workleader) is able to grant an extension.

For information pertaining to payment arrangements for annual adjustments, refer to Equal Payment Plan.

For information pertaining to payment arrangements for Security Deposits, refer to Credit Call Handling.

When an Installment Plan is de-activated (cancelled), the amount will be subject to Late Payment Charges.

An Installment Plan should not be re-established if the customer defaults on the payments.

- What previous collection action has been taken on the account?
- How many days overdue is the account, and how much is overdue?
- Have we made previous payment arrangements with this customer, and have they been kept?
- Does the customer report false payments?
- Has there been an NSF cheque(s) on the account?
- Has the customer made a payment recently?
- How long has the customer been at the premise?
- Is there a Move Out pending?
- Is this balance owing from a previous bad debt?

C) A cash security deposit is required of: (i) a new customer; and (ii) an existing customer;

Calculation of Security Deposit Amount

The Security Deposit amount is based on the average monthly bill on the premise.

If the calculated average monthly bill amount is less than $55.00, the Security Deposit will be automatically waived.

Dollar amounts are rounded up to the nearest dollar.

For customers with a minimum of eight months consumption history, the average monthly bill will be calculated on a case by case basis based on the consumption history of the premise. It will be calculated with the same calculation of EP:

- Readings from 8 – 12 months (depending on availability of data), excluding cancelled bills, final bills, and manual bills
- Calculate the gross amount for each of the above documents
- Add together, total, and prorate the amount for the number of months

If the minimum eight months of consumption history does not exist, the average monthly bill will be retrieved from a custom table that contains the recommended Security Deposit amount based on the following information:

- Is it commercial or residential?
- Is it an apartment or house (for residential)?
- Is the heating included or not?
- What is the billing method (monthly or bi-monthly)?

Once the Average Monthly Bill (AMB) is calculated, using either method, the Security Deposit will be multiplied against the following multipliers:

- **Monthly** customers are charged **AMB x 2** (**Note**: EP customers are treated as monthly)
- **Bi-monthly** customers are charged **AMB x 3**

When there is insufficient consumption history at a premise, the billing system proposes a default amount.

(d) It is appropriate and/or inappropriate to place residential customers on a levelized monthly (or budget) billing plan;

- The Equal Payment Plan (EPP) is a service available to customers to bill their estimated annual cost of service in equal monthly amounts over a 12 month period
- All Contract Accounts are eligible for the EPP
- A customer may request EPP at their existing premises or at the time they move into a new premises
- CCS will review the installment amount to ensure the amount is comparable to the cost of energy used and adjust the amount if necessary. This is called Continual Review
- Accounts are also reviewed when the annual adjustment takes place
- As of April 01, 2008, late payment charges are applicable to overdue amounts based on the Business Rules for Late Payment Charges
- An EPP will be cancelled automatically by CCS when the total outstanding is $70 or greater and the arrears become 63 days past due
- A billing period of less than eight days will not be invoiced
- Using the 'Your Account' feature on bchydro.com/youraccount, customers will be able to view, establish, change, or cancel their EPP

Equal Payment Plan (EPP) Information

- Information is displayed, changed, or cancelled at the Contract level
- CCS uses historical invoice document amounts to calculate the installment amounts at creation and annual review
- EPP is created for the upcoming year and will have 12 installment amounts
- In the 12th month, both the 12th installment and the annual adjustment is billed
- A bill message is included each time the installment amount is adjusted, advising the customer of what the new EPP amount will be as of the next month
- An estimated reading is used for the annual adjustment if an actual reading is not available
- Accumulated balance is referred to as the 'Current Differential' amount
- MRU ends with an 'M' if monthly read, or 'X' if bi-monthly read

When EPP accounts convert to automated meter reading, the account will invoice to 'actual' readings each month if available, even though the MRU displays a 'X' .

- When a future dated Move In is taken and the current customer at the premises is on EPP, the Contract and Installation will continue to show as 'M' and 'X' until the new customer's Move In date, even if the new customer chooses to not be on EPP
- A 'Status to date' message will appear on the invoice each month. For more information, refer to Status Message
- When an EPP has been cancelled, or has had an annual adjustment, the current differential amount (accumulated balance) will not display on the Account Display screen until the next invoicing date

(e) BC Hydro will turn a residential account over to a third party collection agency for collection.

Closed Account - Referral to a Collection Agency

Account balances that remain unpaid after an account has been closed may eventually be referred to a Collection Agency if:

- No payment arrangement has been made
- Payment arrangements were made, but not kept

The following criteria will determine if/when the account is sent to a Collection Agency after Notices have been sent:

- Dunning Procedure
- Dollar amount
- Creditworthiness score
- Number of days outstanding
- No other active residential or Collective account with the same name

For more information, refer to the Dunning Procedure 2 Job Aid to view the Dunning action taken at each Dunning Level for a closed account.

Unpaid final/closed accounts over $25.00 are sent to a Collection Agency by CCS.

On a monthly basis Collection Agencies forward details regarding the debt (amount owing and date) to our Credit Reporting Agent, which is Equifax Canada Inc.

- As per the Credit Reporting Act, any information regarding a debt can only be reported for a period of six years
- Accounts which have been paid will be noted on a customer's credit file as a 'Paid Debt' and will be reported as such for six years
- Equifax Canada Inc. will only report debts which are greater than $100.00

For more information, refer to Collection Agency regarding the individual agencies receiving referrals from BC Hydro.

A Dunning Lock must be placed on an account that you do not want referred.

An Estate will be coded with Dunning Procedure FD (Deceased/Stop Trace) to prevent the account from being referred to a Collection Agency.

When a balance from a referred account is recalled and transferred to a Business Partner's new account, the Collection Agency is noted via CCS and they close that file.

210.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.210.1 Please provide a copy of all reports, evaluations, memos, analyses or other written documents of any nature containing an articulation of performance indicators on which empirical data has been collected for BC Hydro with respect to:

(a) Debt prevention;
(b) Debt management;
(c) The treatment of vulnerable residential customers;
(d) Customer satisfaction.

RESPONSE:

As noted in BC Hydro's response to BCOAPO IR 1.198.1, BC Hydro utilizes a number of performance metrics related to arrears management. BC Hydro also uses customer satisfaction (CSAT) measures that include:

- **Transactional CSAT – the percentage of customers surveyed that were satisfied or very satisfied with their call centre experience; and**
- **Corporate CSAT:**
  - **The overall satisfaction with BC Hydro as obtained through a general population survey, as tracked in BC Hydro's Service Plan; and**
  - **As represented on a 10-point scale, the satisfaction of BC Hydro as obtained through a general population survey. This survey includes segmentation by customer income.**

Please refer to the following attachments to this response:

Attachment 1 – A summary of Transactional CSAT by month.

Attachment 2 – BC Hydro's 2015/16 – 2017/18 Service Plan.

Attachment 3 – Relevant extracts of BC Hydro's residential CSAT report for November 2015.

Attachment 4 – A summary of Corporate CSAT (10-point scale) by income.

Attachment 5 – A summary of key arrears management and bad debt metrics by month.

Transactional CSAT

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2012	91.5	91.2	90.3	89.4	88.3	87.8	87.5	87.1	87.2	87.0	87.1	91.3
2013	91.0	90.7	90.4	90.0	89.8	89.7	89.8	89.8	89.9	90.0	89.8	89.8
2014	87.1	88.5	89.6	88.2	89.7	90.9	90.8	87.4	86.8	84.8	88.6	92.2
2015	88.7	89.5	89.8	88.4	89.3	89.4	90.5	89.2	91.8	91.9	90.5	

BC Hydro and Power Authority

2015/16 – 2017/18
SERVICE PLAN

For more information on BC Hydro contact:

333 Dunsmuir Street
Vancouver, BC
V6B 5R3

Lower Mainland
604 BCHYDRO
(604 224 9376)

Outside Lower Mainland
1 800 BCHYDRO
(1 800 224 9376)

bchydro.com

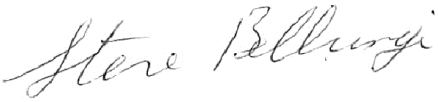
BC Hydro's Service Plan can be found online at
http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html

Accountability Statement

The 2015/16 - 2017/18 BC Hydro service plan was prepared under the Board's direction in accordance with the *Budget Transparency and Accountability Act* and the B.C. Reporting Principles. The plan is consistent with government's strategic priorities and fiscal plan. The Board and Management are accountable for the contents of the plan, including what has been included in the plan and how it has been reported.

All significant assumptions, policy decisions, events and identified risks, as of January 31, 2015, have been considered in preparing the plan. The performance measures presented are consistent with BC Hydro's mandate and goals, and focus on aspects critical to the organization's performance. The targets in this plan have been determined based on an assessment of BC Hydro's operating environment, forecast conditions, risk assessment and past performance.

Stephen Bellringer



Board Chair

Table of Contents

Accountability Statement **3**

Strategic Direction and Context **5**

Performance Plan **7**

Financial Plan **14**

Summary Financial Outlook 14

Key Forecast Assumptions 15

Sensitivity Analysis and Management Perspective on Future Financial Outlook 16

Capital Plan and Major Projects 17

Appendices **21**

Appendix A: Hyperlinks to Additional Information 21

Appendix B: Capital Projects Descriptions 22

Appendix C: Subsidiaries and Operating Segments 28

Strategic Direction and Context

Strategic Direction

BC Hydro was created over 50 years ago to generate and deliver clean, reliable and competitively priced electricity to homes and businesses throughout British Columbia. The electricity generated by our dams and delivered by our transmission and distribution infrastructure has powered B.C.'s economy and quality of life for generations.

To meet the objectives set out in the B.C. Government's Mandate Letter, BC Hydro has strategies in place to safely and reliably meet the energy needs of British Columbians while also responsibly managing costs and maintaining competitive rates.

Providing reliable power to British Columbians requires maintaining the health of our infrastructure, identifying future supply to meet customers' needs, and putting in place new technologies and work methods to support the reliability and safety of our system.

Guided by the Province's 10 year plan for rates, BC Hydro is implementing the Integrated Resource Plan and the Taxpayer Accountability Principles. In fiscal 2016, BC Hydro will continue to carefully manage costs and foster a culture of cost consciousness and accountability to provide services as efficiently, effectively, and safely as possible.

In December 2014, the B.C. Government approved the Site C Clean Energy Project to proceed to construction in summer 2015. Once completed in 2024, Site C will provide clean, reliable and cost-effective electricity for more than 100 years. It will generate enough electricity each year to power the equivalent of about 450,000 homes.

Operating Environment

Priorities

Today, B.C.'s electrical system remains the backbone of our economy and quality of life. Our customers count on us to deliver clean, reliable and affordable electricity to their homes, businesses and industries. They expect us to be open, fair and responsible in our interactions with them. Customer expectations are a priority for BC Hydro.

As announced in November 2013, the Province's 10 year plan creates rate certainty for BC Hydro customers until the end of fiscal 2019. In order to meet this commitment, BC Hydro will continue to operate in an efficient manner to reduce costs. As a result we are expected to continue to have some of the lowest rates in North America for residential, commercial and industrial customers.

Within this 10 year plan for rates, BC Hydro will continue with its significant capital plan, spending an average of $2.4 billion per year for the next 10 years to invest in the upgrading of ageing assets and construction of new infrastructure to support British Columbia's growing population and economy.

Along with this investment in our system, BC Hydro remains focused on conservation and energy efficiency measures, including the *Clean Energy Act's* objective to meet at least two-thirds of future

demand growth through conservation by 2020. This will be achieved through the efforts of our customers alongside the $1.6 billion investment in conservation programs that BC Hydro will make over the 10 year plan for rates.

We will also ensure the safe and reliable supply of electricity through ongoing and regular maintenance of our generation, transmission and distribution systems. Supplying safe and reliable electricity also includes preventing employee, contractor and public injuries; mitigating and responding to outages from storms and other events; and, continuing to enhance our disaster preparedness in alignment with industry best practices.

We recognize the importance of building mutually-beneficial relationships with Aboriginal communities. In fiscal 2016, we will continue to develop a more comprehensive approach for long-term and effective business relationships and identify opportunities for collaboration with Aboriginal people in B.C. An example of this collaboration with Aboriginal groups is the Iskut Extension Project, which went into service in December 2014. This extension of the transmission system, combined with a new substation and distribution line, will not only provide clean power for Imperial Metal's Red Chris Mine and other potential industrial developments but also deliver clean electricity to the community of Iskut for the first time.

With prudent reinvestment, careful planning and strong, respectful relationships, BC Hydro is well positioned to deliver clean, reliable power for the long-term benefit of our growing province.

Risks and Opportunities

BC Hydro strives to manage all the risks it faces on a cost effective basis, taking into account the potential benefits to be gained in return for acceptance of the risk. Risks that could significantly impact BC Hydro meeting its objectives are outlined at www.bchydro.com/serviceplan.

Performance Plan

Goals, Strategies, Measures and Targets

BC Hydro's vision is: ***Powering B.C. with clean, reliable electricity for generations*** and we have six core values that are essential to our success: accountability, integrity, safety, service, teamwork and ingenuity. In addition, six strategic goals guide our actions each supported by corresponding strategies, performance measures and targets. Each performance measure has a definition and rationale, as well as benchmarking measures that allow a comparison of performance over time. These measures track our progress on delivering key priorities. BC Hydro management is responsible for measuring performance against targets, and results are reported to the Board on a quarterly basis and publicly in the Annual Report. The vision and its associated values and strategic goals support transparency and accountability as required by Government under the Taxpayer Accountability Principles.

Taxpayer Accountability Principles:
Service
BC Hydro will continue to focus on providing effective value-for-money public services and programs by setting and monitoring appropriate targets specific to our costs, rates, reliability and customer satisfaction.

Goal 1: Safely Keep The Lights On

Safely and reliably meet the electricity needs of our customers through integrated planning and technology, and in the operation, maintenance and advancement of our system.

Strategies

- Continue our focus on employee, contractor and public safety by implementing our five-year safety strategy, which includes:
  - improving the culture through implementing BC Hydro's Safety Taskforce's 21 recommendations;
  - focussing on regulatory compliance, particularly in moving the Asbestos Management program into day to day operations (sustainment), consolidating and enhancing the Confined Space program, and updating the Crane/Hoist authorizations and certification standards; and,
  - focussing on electrical safety with an emphasis on arc flash hazards, improvements to electrical system rules and procedures for employees and contractors, as well as expanding the public safety electrical awareness program.
- Ensure the reliability of the system by effectively implementing capital and maintenance programs to manage overall asset health.
- Improve the overall outage detection and restoration process using data from our Smart Meter Program.
- Continue to effectively manage dam safety issues, risks and regulatory requirements.

- Identify and address vulnerabilities in our operating system on a regional basis (including vulnerability to a major seismic or catastrophic event) and have in place well practiced emergency response plans in order to improve overall system reliability.

Performance Measures 1-8[1]

Performance Measures	Four Year Avg.	Actual F2013	Actual F2014	Target F2015	**Forecast F2015**	Target F2016	Target F2017	Target F2018
Safety measures								
Zero Fatality & Serious Injury[2] [Loss of life or the injury has resulted in a permanent disability]	1.25	2[3]	0	0	**1**[4]	0	0	0
Severity,[2,5] [Number of calendar days lost due to injury per 200,000 hours worked]	30.9	45.1[6]	28.9	25.0	**20.0**	25.0	25.0	25.0
Lost Time Injury Frequency[2,8] [Number of employee injury incidents resulting in lost time (beyond the day of the injury) per 200,000 hours worked]	1.0	1.0	0.9	NR[7]	**1.0**	1.0	0.9	0.9
Reliability measures								
CAIDI (duration)[9] [average interruption in hours per interrupted customer]	2.22	2.12	2.30	2.25	**2.45**	2.30	2.30	2.30
SAIDI (duration)[9] [total outage duration (in hours) experienced by an average customer in a year]	NR	NR	3.58	3.15	**3.19**	3.22	3.22	3.11
SAIFI (frequency)[9] [Number of sustained disruptions per year] (excluding major events)	1.58	1.29	1.56	1.40	**1.30**	1.40	1.40	1.35
CEMI-4 (%)[9] [Customers experiencing four or more outages]	11.88	9.10	12.35	11.00	**8.43**	11.00	11.00	10.50
Winter Generation Availability (%)	96.50	98.10	96.80	96.40	**96.40**	96.40	96.40	96.40

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.
[2] BC Hydro's safety performance measures do not include contractor or public safety injuries or fatalities.
[3] Fiscal 2013 Actual reflects the July 2014 reclassification of an incident from August 2012 as a serious injury based on recent information from WorkSafeBC on the extent of the worker's injuries. Neither of the incidents in fiscal 2013 resulted in a fatality.
[4] The fiscal 2015 forecast reflects that a serious injury from an electrical contact occurred November 2014.
[5] The severity targets for fiscal 2016 and fiscal 2017 have been revised to better reflect past performance.
[6] The fiscal 2013 Severity result of 45.1 is unusually high compared to other years. Over 40 per cent of the fiscal 2013 Severity result is due to five injuries resulting in considerable time loss (180 days or more). Traditionally, BC Hydro only experiences one or two injuries in a year with this amount of time loss.
[7] There was no official Lost Time Injury Frequency target set for fiscal 2015 as this is a new measure.
[8] Replacement of the All Injury Frequency Safety Measure with Lost Time Injury Frequency. Focusing on Lost Time Injury Frequency encourages managers to identify modified work duties for job categories and locations where workers experience injury, enabling injured workers to stay on the job while they recover. The earlier an injured worker is able to safely return to productive employment and maintain his or her positive connection to the workplace, the more likely he or she is of obtaining maximum recovery. With the increased granularity this metric provides, the organization is better able to focus its efforts on managing the hazards that can lead to Lost Time injuries.
[9] Annual targets are based on a number of factors including long-term historic reliability trending, current year performance, previous years investments and future years investment plans. Targets for fiscal 2016 and fiscal 2017 have been adjusted to reflect these factors but remain in line with historical performance.
Note: Reliability targets are based on specific values, however performance within 10 per cent is considered acceptable given the wide range of variations in weather patterns and uncontrollable elements that can significantly disrupt the electrical system. BC Hydro measures reliability under normal circumstances, because major events are not predictable and largely uncontrollable. The reliability measure is therefore based on data that excludes major events. BC Hydro reviews performance during major events and takes the performance into consideration in reliability improvement initiatives.

Goal 2: Succeed Through Relationships

Gain support for our work by building trusted relationships with First Nations, customers, suppliers and the communities we serve.

Taxpayer Accountability Principles:
Respect
BC Hydro will continue to ensure a high level of engagement and/or consultation on significant initiatives such as our large capital plan, the Rate Design Application, and implementing the Taxpayer Accountability Principles for 2015.

Strategies

- Increase the integration and consistency between the different customer channels that support new connections, billing, and program participation such as BC Hydro's demand side management implementation.
- Continue to meet the evolving needs of customers by refining the customer notification process for work requiring a planned outage, and by increasing self-service options through both our web and mobile platforms.
- Sustain gold-level certification under the Progressive Aboriginal Relations program by maintaining leading practices in the areas of Aboriginal employment, business development, capacity development and community engagement.
- Increase project and operational support by continuing to build collaborative, respectful and mutually beneficial relationships with First Nations.
- Continue to advance the Clean Energy Strategy, as outlined in the Integrated Resource Plan, which includes promoting First Nations participation in clean energy projects.

Performance Measure 9 - 12[1]

Measure	Four Year Avg.	Actual F2013	Actual F2014	Target F2015	**Forecast F2015**	Target F2016	Target F2017	Target F2018
CSAT Index [Customer Satisfaction Index: % of customers satisfied or very satisfied]	86.8	86.0	85.0	85.0	**85.0**	85.0	85.0	85.0
Billing Accuracy [% of accurate bills]	98.6	98.5	99.1	99.0	**99.4**	99.0	99.0	99.0
First Call Resolution[2] [% of customer calls resolved first time]	71.5	68.0	71.0	73.0	**70.0**	71.0	71.0	71.0
Progressive Aboriginal Relations Designation[3]	N/A	Gold	Gold	Gold	**Gold**	Gold	Gold	Gold

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.
[2] The fiscal 2016 and fiscal 2017 targets were reduced compared to the 2014/15-2016/17 Service Plan due to the movement of a greater number of less complicated calls to the self-serve environment (web and phone) resulting in the call centre handling a greater percentage of complex calls that may not lend themselves to resolution on the first call.
[3] BC Hydro attained a gold-level designation from the Canadian Council for Aboriginal Business in fiscal 2013 which is valid for a three year period.In fiscal 2016, BC Hydro will apply for the next certification.

Goal 3: Mind Our Footprint

Create a sustainable energy future in B.C. by carefully managing our impacts on the environment and fostering an energy conservation and efficiency culture.

Strategies

- Implement the Demand-Side Management Plan, including the *Clean Energy Act's* objective to meet at least two-thirds of future demand growth through conservation by 2020.
- This includes Power Smart programs and conservation rate structures, supporting new energy efficiency regulations, and maintaining an energy conservation and efficiency culture.
- Develop and implement appropriate independent power projects; manage energy purchased from independent power producers; and, advance clean energy capacity resources in order to continue to meet the 93 per cent clean energy objective in the *Clean Energy Act*.
- Pursue cost-effective greenhouse gas (GHG) emission reductions from our buildings and vehicle fleet and purchase offsets for our residual emissions thereby contributing to the Province's goal of carbon neutrality in the public sector.
- Support the Province's goal of reducing the carbon intensity of the transportation energy used by British Columbians by supplying low carbon electricity for transportation purposes including shore power for ships.
- Manage the impact on the environment from BC Hydro's new developments and retrofits of existing facilities by incorporating an "avoid, minimize and offset" approach to project design, planning and implementation.
- Continue to implement environmental studies and projects related to water licence requirements under BC Hydro's Water Use Plans, to confirm the suitability of operational controls at hydroelectric generating plants.
- Continue to implement the PCB electrical equipment phase-out strategy, and the long-term strategy for the handling, decontamination and disposal of PCB-contaminated equipment and materials.
- Ensure resources, training and tools are in place at BC Hydro's facilities and throughout our operations to identify risks and prevent environmental incidents, and deploy the most effective approaches to minimize impacts when incidents occur.
- Work in partnership with First Nations and communities to understand impacts related to managing BC Hydro's assets and implement compensation programs and other environmental projects reflective of this input.

Performance Measures 13 - 16[1]

Performance Measures	Four Year Avg.	Actual F2013	Actual F2014	Target F2015	**Forecast F2015**	Target F2016	Target F2017	Target F2018
Demand Side Management (DSM) (GWh/year)[2]	This is a cumulative target; an average is not applicable.	4,460	4,776	5,500	**4,380**	5,000	5,600	6,100
Clean Energy (%)[3]	97.1	98.2	97.1	93.0	**93.0**	93.0	93.0	93.0
Electricity Production GHG Emissions (kilotonnes CO_2e)[4,5]	Metric moved to calendar year in F2012.	631	730	740	**740**	1,110	1,120	1,270

Carbon Neutral Program Emissions (kilotonnes CO_2e)[4,6]	Average cannot be calculated. Metric moved to report calendar year in F2012.	28.8	27.0	29.0	**27.3**	28.0	28.0	28.0

[1] Performance Measure descriptions, rationale, data source information and benchmarking is available online at www.bchydro.com/performance.
[2] Target numbers are rounded values presented as cumulative run-rate savings since 2008 and include energy savings from Power Smart programs as well as from codes/standards and rate structures. The energy savings forecast for fiscal 2015 and targets for fiscal 2016, fiscal 2017 and fiscal 2018 include the impact of the evaluation of the energy savings from conservation rate structures, which have largely contributed to a reduction of the DSM targets relative to the previous Service Plan.
[3] The Clean Energy Target represents the minimum threshold generation target in accordance with the B.C. Government's requirement that at least 93 per cent of electricity generation in the province be from clean or renewable resources. BC Hydro's forecast is based on actual resource use and is consistent with previous years.
[4] All actuals, forecast and targets for Electricity Production GHG Emissions and Carbon Neutral Program Emissions are presented on a calendar year basis, not fiscal year. For Electricity Production, this is to ensure consistency with GHG emissions reports filed under *the Canadian Environmental Protection Act, 1999* and the B.C. Reporting Regulation. For Carbon Neutral this is to ensure consistency with the B.C. Carbon Neutral Government Regulation.
[5] The upward revision of the plan compared to previous Service Plan is primarily related to the potential for higher production from existing BC Hydro and independent power producer thermal plants.
[6] The targets are based on an updated forecast of emissions from the vehicle fleet, buildings and paper use.

Goal 4: Foster Economic Development

Foster economic development opportunities across B.C. through our projects, practices and advancement of the energy efficiency and clean energy sectors.

Taxpayer Accountability Principles:
Accountability
Accountability is one of BC Hydro's core values and BC Hydro's strategic goals align directly to the Government's strategic mandate to support economic development. We keep rates competitive by responsibly managing the business; and, we develop and promote positive, mutually beneficial relationships with First Nations, two examples of how we are supporting economic growth in the Province.

Strategies

- As outlined in the Integrated Resource Plan, advance a set of actions that support a diverse clean energy sector and promote clean energy opportunities for First Nations.
- Support the Province's priorities through implementation of projects such as transmission upgrades between Prince George and Kitimat that are required to prepare to meet future LNG requirements; and, adding supply to the northeast part of the province through the Peace Region Electricity Supply project to meet industrial load growth in the Dawson Creek/Groundbirch area.
- Help expand and retain current customers by improving the competitiveness of their businesses through Power Smart programs and the delivery of competitively priced electricity.

BC Hydro continues to enable economic development and will measure performance through reliability, maintaining competitive rates, and through implementing our capital plans.

Goal 5: Maintain Competitive Rates

Deliver value for British Columbia and maintain competitive rates by efficiently and responsibly managing our business.

Strategies

- Prudently implement the 10 year plan for rates, the Integrated Resource Plan and BC Hydro's capital plan to ensure a cost-effective electricity supply.
- Continue to improve operational excellence, safety and reliability by improving work delivery methods, resourcing strategies, and integrated planning.
- Continue to implement supply chain strategies to deliver improved operational performance and efficiencies.
- Begin building Site C, a third dam and generating station on the Peace River, which is the most cost-effective way to meet the long-term need for energy and dependable capacity.

Taxpayer Accountability Principles:
Cost Consciousness (Efficiency)
BC Hydro will continue to foster a culture of cost consciousness and operate within the 10 year plan by focussing on management and control of costs including implementing process improvements in order to realize efficiencies.

Taxpayer Accountability Principles:
Appropriate Compensation
BC Hydro will continue to provide sustainable total compensation to attract the best candidates, align employees to our key objectives, retain top performers and maintain employee well-being while also keeping rates low for customers.

Performance Measures 17 - 20[1]

Performance Measures	Four Year Avg.	Actual F2013	Actual F2014	Target F2015	**Forecast F2015**	Target F2016	Target F2017	Target F2018
Competitive Rates[2]	1st quartile	1st quartile	1st quartile	1st quartile	**1st quartile**	1st quartile	1st quartile	1st quartile
Net Income[3] ($ million)	NA[4]	509	549	582	**588**	653	693	707
Operating Costs[3,5] ($ million)	NA[4]	705	702	706	**706**	713	730	737
Project Budget to Actual Cost[6]	-4.75% on $3.33 billion[7]	+0.83% on $3.29 billion	-4.75% on $3.33 billion	This is a new metric. A target was not set for fiscal 2015.	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts	Within +5% to -5% of budget excluding project reserve amounts

[1] Performance Measure definitions, rationales, data sources, and benchmarking information are available at www.bchydro.com/performance.
[2] Based on the annual HydroQuebec Report on Electricity Rates in North America.
[3] Performance within (+/-) 0.5% is considered acceptable.
[4] As a result of reintegration of BCTC in July 2010 and changes to the presentation of certain financial statement items, previous years' numbers are not comparable.
[5] Operating Costs are defined as personnel, materials and external services expenses included in income that are incurred in the day-to-day operation of BC Hydro's electric utility, net of recoveries, capitalized costs and reclassification adjustments.
[6] Project Budget to Actual Cost metric is new for Fiscal 2016. The data includes Generation, Substation and Transmission Line projects managed by the Project Delivery groups in Generation, and Transmission and Distribution . Annually, BC Hydro reflects the past 5 years' performance in delivering capital projects. This is a 5 year rolling data set of actual costs compared to original approved full scope implementation budgets not including project reserve amounts, for capital projects that were put into service during the period.
[7] This is a 5 year rolling average reflecting fiscal 2010 to fiscal 2014.

Goal 6: Engage a Safe and Empowered Team

Empower a team that is committed to safety, innovative and prepared for the future.

Strategies

- Address workforce gaps to ensure recruitment and development efforts provide a readily available talent pool for specialized, critical roles.
- Ensure the optimal and diverse complement of new recruits; skilled, experienced and high-performing employees; and, contracted or outsourced service providers.
- Ensure organizational leaders have the training and tools to support and encourage high performance and engage teams to work together collaboratively, safely, and effectively.

Note: *For information on how BC Hydro is working to ensure the safety of employees, contractors and the public see Goal 1.*

Performance Measure 21[1]

Performance Measures	Four Year Avg.	Actual F2013	Actual F2014	Target F2015	**Forecast F2015**	Target F2016	Target F2017	Target F2018
Employee Engagement (%)[2]	Survey tool updated in F2013	78 Index score was 79.	79 Index score was 79.	Meet or exceed Towers Watson's Global Utilities Index	**82** **Index score is 79.**	Meet or exceed Towers Watson's Global Utilities Index	Meet or exceed Towers Watson's Global Utilities Index	Meet or exceed Towers Watson's Global Utilities Index

[1] Performance Measure definitions, rationales, data sources, and benchmarking information are available at www.bchydro.com/performance.
[2] The target is to meet or exceed the annual Towers Watson Global Utilities Index Score (2014 index score was 79 per cent).

Financial Plan

Summary Financial Outlook

Consolidated Statement of Operations[1] ($ millions)	**2013/14 Actual**	**2014/15 Forecast**	**2015/16 Forecast**	**2016/17 Forecast**	**2017/18 Forecast**
Revenues ($000)					
Domestic	4,319	4,828	5,057	5,403	5,604
Trade	1,073	1,026	1,029	1,024	1,012
Total	**5,392**	**5,854**	**6,086**	**6,427**	**6,616**
Expenses ($000)					
Operating Costs					
Cost of Energy	2,145	2,310	2,280	2,525	2,590
Other operating expenses					
Personnel expenses, materials & external services [2]	848	864	900	963	1,006
Amortization	995	1,212	1,254	1,253	1,246
Finance charges	598	632	751	733	796
Grants and taxes	203	209	218	229	238
Other	53	39	30	31	33
Total	**4,843**	**5,266**	**5,433**	**5,735**	**5,909**
Net Income	**549**	**588**	**653**	**693**	**707**

Consolidated Statement of Operations[1] ($ millions)	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast
Net Debt [3]	**15,461**	**16,826**	**17,942**	**19,122**	**20,613**
Equity	**3,865**	**4,207**	**4,485**	**4,780**	**5,189**
Capital Expenditures	**2,036**	**2,268**	**2,234**	**2,277**	**2,718**

[1] Table may not add due to rounding.
[2] These amounts are net of capitalized overhead and consists of the following:

	F2014	F2015	F2016	F2017	F2018
Domestic Base Operating Costs	702	706	713	730	737
Other	147	158	187	233	269
	848	864	900	963	1,006

Other largely consists of Powerex & Powertech operating costs, operating costs related to energy purchase agreements accounted for as capital leases, and the transitioning of IFRS-ineligible capital overhead into operating costs over a 10-year period.
[3] Debt figures are net of sinking funds and cash and cash equivalents.

Key Forecast Assumptions

Key Assumptions	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast
Growth and Load					
B.C. Real Gross Domestic Product Growth (%)[1]	1.9	1.9	2.3	2.5	2.5
Domestic Sales Load Growth (%)[2,3]	(7.00)	0.46	3.97	1.52	3.16
Residential Sales Load Growth (%)[2]	1.48	(0.17)	0.63	(0.61)	0.51
Light Industrial and Commercial Sales Load Growth (%)[2]	0.64	0.95	0.75	1.21	1.61
Large Industrial Sales Load Growth (%)[2]	3.60	3.82	8.95	3.85	6.13
Domestic Load (GWh):					
Domestic Sales Volume (GWh)[3]	53,018	53,262	55,379	56,224	57,998
Line Loss and System Use (GWh)	5,900	4,938	5,502	5,571	5,700
Total Domestic Load (GWh)	58,918	58,201	60,882	61,795	63,698
Energy Generation					
Total System Water Inflows (% of average)	95	95	100	100	100
Sources of Supply to Meet Domestic Load:					
Net Hydro Generation (GWh)	46,590	44,771	46,695	46,123	46,602
Market Electricity Purchases (GWh)[4]	918	277	1,191	1,483	2,041
Independent Power Producers and Long-term Purchases (GWh)	11,025	12,766	12,608	13,833	14,694
Thermal Generation (GWh)	385	387	387	355	361
Sources of Supply for Domestic Load (GWh)	58,918	58,201	60,882	61,795	63,698
Average Mid-C Price (U.S.$/MWh)	36.18	32.52	32.22	34.24	36.89
Average Natural Gas Price at Sumas (U.S.$/MMBTU)	4.20	4.11	3.82	3.94	4.13
Financial					
Canadian Short-Term Interest Rates (%)[5]	1.27	0.99	1.32	1.97	2.73
Canadian Long-Term Interest Rates (%)[5]	3.16	2.95	3.68	4.09	4.95
Foreign Exchange Rate (U.S.$:Cdn$)[5]	0.9452	0.8980	0.8561	0.8645	0.8758

[1] Economic assumptions, based on calendar year, from Ministry of Finance First Quarterly Report September 2014.
[2] Includes the impact of Demand-Side Management programs.
[3] Includes surplus sales volume.
[4] Assumes that gas fired power generation capability available to service domestic demand is sometimes displaced by more cost-effective market purchases.
[5] Fiscal 2014; three months rate for short term and 10 years for long term. Fiscal 2015 to fiscal 2018, financial assumptions from Ministry of Finance, December 2014.

Sensitivity Analysis

Factor	Change	Approximate change in fiscal 2016 earnings before regulatory account transfers (in $ millions)
Hydro Generation (GWh)[1]	+/- 1%	15
Electricity trade margins	+/- 10%	15
Interest rates	+/- 1%	50
Exchange rates (US/ CDN)	$0.01	5
Weather	1°C change in average temperature	25

[1] Assumes a change in hydro generation is offset by corresponding change in energy imports. (i.e. increase in hydro generation is offset by decrease in energy imports.)

Management Perspective on Future Financial Outlook

In November 2013, the Province, as part of the 10 year plan for rates, announced rate increases for BC Hydro in fiscal 2015 and fiscal 2016 of 9 per cent and 6 per cent, respectively, with rate increases for fiscal 2017 to fiscal 2019 capped at 4 per cent, 3.5 per cent and 3 per cent, respectively. The 10 year plan for rates included several rate mitigation actions to lower future year rate increases, including changing water rental rates, lowering the return on equity, reducing dividends and smoothing general rate increases through the use of a regulatory account.

BC Hydro prepared the current financial projections for revenues and expenses through fiscal 2018 which were approved by the Board and submitted to the Ministry of Finance in January 2015. These financial projections are consistent with the 10 year plan for rates.

Capital Plan and Major Projects

Capital Expenditure by Year and Type and Function

($millions)	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast
Capital Expenditures by Type[1]					
Sustaining	979	1,125	1,209	1,202	1,419
Growth	1,057	1,143	1,025	1,075	1,299
Subtotal – BC Hydro Capital Expenditures before CIA	2,036	2,268	2,234	2,277	2,718
Contributions-in-Aid (CIA)[2]	(131)	(260)	(131)	(144)	(158)
Total – BC Hydro Capital Expenditures net of CIA	1,905	2,008	2,103	2,133	2,560
Capital Expenditures by Function					
Generation	496	635	637	610	717
Transmission and Distribution	1,334	1,336	1,147	902	1,009
Properties, Technology and Other	206	283	268	274	279
Site C	-	14	182	491	713
Subtotal – BC Hydro Capital Expenditures before CIA	2,036	2,268	2,234	2,277	2,718
CIA	(131)	(260)	(131)	(144)	(158)
Total BC Hydro Capital Expenditures net of CIA	1,905	2,008	2,103	2,133	2,560

[1] BC Hydro classifies capital expenditures as either sustaining capital or growth capital:

- Sustaining capital includes expenditures to ensure the continued availability and reliability of generation, transmission and distribution facilities. It also includes expenditures to support the business, such as vehicles and information technology.
- Growth capital is required to meet customer load growth and other business investments. Growth capital expenditures relate to the expansion of existing generation assets as well as expansion and reinforcement of the transmission and distribution system, and includes Site C.

[2] Contributions in aid of construction are amounts paid by certain customers toward the cost of property, plant and equipment required for the extension of services to supply electricity.

Planned Projects over $50 million

BC Hydro has planned for the following projects, each with capital costs expected to exceed $50 million, listed according to targeted completion date. These projects have been approved by the Board of Directors. Appendix B provides further details on each $50 million project.

Capital Project (Project descriptions can be found in Appendix B)	**Targeted Completion Date (calendar year)**	**Total Cost ($ millions)**	**Life to Date (LTD) Cost** as of December 31, 2014 **($ millions)**
Projects Recently Put Into Service			
Vancouver City Central Transmission	March 2014, In-Service	$171	$171
Northwest Transmission Line Project	July 2014, In-Service	$716	$664
Total cost represents the gross cost of the project and has not been netted for contributions, which total $220 million from the Federal Government and a customer prior to the in-service date. Additional annual payments will be received from a customer for 20 years after the in-service date.			
Mica SF_6 Gas Insulated Switchgear Replacement Project	August 2014, In-Service	$199	$175
Iskut Extension Project	December 2014, In-Service	$209	$167
The total cost represents the gross costs of the project and has not been netted to reflect the contribution from the customer towards the construction of the transmission line. The total cost increased from $180M to $209M to reflect a higher cost for the transmission line.BC Hydro purchased the transmission line upon completion by the customer at a fixed cost. The additional cost of the line, including the cost increase, was paid for by the customer and the net cost to BC Hydro for the project has not increased.			
Ongoing and Planned			
Merritt Area Transmission Project	2015 Targeted completion	$65	$42
Dawson Creek/Chetwynd Area Transmission Project	2015 Targeted completion	$296	$183
G.M. Shrum Units 1 to 5 Turbine Replacement	2015 Targeted completion	$272	$144
Long Beach Area Re-Inforcement	2015 Targeted completion	$56	$22
Surrey Area Substation Project	2015 Targeted completion	$94	$39
Interior to Lower Mainland Project	2015 Targeted completion	$725	$574
Smart Metering & Infrastructure Program	2015 Targeted completion	$930	$721
Smart Metering & Infrastructure Program amount includes both capital costs and operating expenditures subject to regulatory deferral.			

Hugh Keenleyside Spillway Gate Reliability Upgrade	2015 Targeted completion	$123	$87
Upper Columbia Capacity Additions at Mica – Units 5 & 6	2015 Targeted completion	$714	$486
Big Bend Substation	2017 Targeted completion	$56	$18
Ruskin Dam Safety and Powerhouse Upgrade	2017 Targeted completion	$748	$283
John Hart Generating Station Replacement	2019 Targeted completion	$1,093	$239
Cheakamus Unit 1 and Unit 2 Generator Replacement	2019 Targeted completion	$74	$4
Site C Clean Energy Project	2024* Targeted completion	$8,335**	$415 (deferred capital)

**Planned in-service date for all units. This timeline reflects the project's current schedule and is subject to change based on a review of the construction schedule.*

***Site C forecast and life-to-date amounts include both capital costs and expenditures subject to regulatory deferral. Total cost excludes the Project Reserve of $440 million (established by the British Columbia Government to account for events outside of BC Hydro's control that could occur during construction) which is held by the Treasury Board. The increase to the 2010 capital cost estimate from $7,900 million to $8,335 million reflects costs associated with the change from the harmonized sales tax to the provincial sales tax, and a revised construction start date from January 2015 to summer 2015.*

Contemplated Projects over $50 million

BC Hydro is contemplating the following projects over $50 million commencing during fiscal 2016-fiscal 2018, listed in alphabetical order. These projects are in the initial project phases; scope, final cost and benefit assessment, and completion dates are still to be determined. These projects are not yet approved by the Board of Directors.

Capital Project (Project descriptions can be found in Appendix B)	
Bridge River 2 Units 5 and 6 Upgrade	Peace Region Electric Supply
Bridge River 2 Units 7 and 8 Upgrade	Prince George to Terrace Capacitors
Clowhom Unit Upgrade	Revelstoke Improve Left Bank Slope Stability
Downtown Vancouver Electricity Supply Plan	Revelstoke Unit 6 Installation
G.M. Shrum G1-G10 Control System Upgrade	Seven Mile Unit 1-3 Turbines Overhaul
Horne Payne Substation Upgrade	Strathcona Dam Spillway Upgrade
John Hart Dam Seismic Upgrade	Strathcona Dam Discharge Upgrade
Ladore Dam Spillway Gates Upgrade	Terrace – Kitimat Transmission Project
Metro North System Supply Reinforcement	W.A.C. Bennett Dam Rip-Rap Upgrade
Northwest Substation Upgrades Project	

Appendix A:

Hyperlinks to Additional Information

Corporate Governance

Information about Corporate Governance can be found at:
http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html.

This includes links to information regarding:

- Board of Directors
- Executive Team
- Code of Conduct

Taxpayer Accountability Principles:

Integrity

Integrity is one of BC Hydro's core values. BC Hydro has an Ethics Officer, and an Employee Code of Conduct which provides guidance on the standards of conduct expected of Directors, Employees and Contractors of BC Hydro. This includes guidelines on conflict of interest to ensure decisions and actions are transparent, ethical and free from conflict of interest.

Operating Environment

Information about BC Hydro's Operating Environment can be found at:
http://www.bchydro.com/about/accountability_reports/financial_reports/service_plan.html.

This includes links to information regarding:

- About BC Hydro: Organizational Overview
- Mandate and Legislation
- Risks and Opportunities
- Performance Measures Data Analysis, Benchmarking and Rationale

Appendix B:

Capital Project Descriptions

Projects Recently Put Into Service

(All costs are expressed in millions) (Life to Date costs as of December 31, 2014)

Vancouver City Central Transmission

March 2014, In-Service $171 Total cost $ 171 Life to Date (LTD) cost

Built an enclosed 230/12 kV substation in the Mt. Pleasant area of Vancouver and two new underground 230 kV transmission lines connecting the new substation to the existing transmission network to serve growing loads in the Mt. Pleasant/False Creek area and maintain a reliable supply of electricity to other areas of Vancouver.

Northwest Transmission Line Project

July 2014, In-Service $716 Total cost $664 LTD cost

Constructed an approximately 340 km, 287 kV transmission line between Skeena Substation near Terrace and a new substation near Bob Quinn Lake to ensure a reliable supply of clean power to potential industrial developments in the area, and provide a secure interconnection point for clean generation projects. The total cost decrease from $746M to $716M is due to lower than estimated costs for line construction, clearing work, overhead and interest during construction.

Total cost represents the gross cost of the project and has not been netted for contributions, which total $220 million from the Federal Government and a customer prior to the in-service date. Additional annual payments will be received from a customer for 20 years after the in-service date.

Mica SF_6 Gas Insulated Switchgear Replacement Project

August 2014, In-Service $199 Total cost $175 LTD cost

Replace the switchgear system at the Mica Generating Station and install additional switchgear capacity to accommodate the future Units 5 and 6 additions to ensure the reliability of this key generating station and reduce SF6 (a greenhouse gas) leakage. The switchgear system, energized at 500 kV, conducts energy from the Mica underground powerhouse to the surface, where it transitions to transmission lines.

Iskut Extension Project

December 2014, In-Service $209 Total cost $167 LTD cost

The project includes construction of a customer-built 287 kV transmission line extension from Bob Quinn Substation to the customer's mine, via a new BC Hydro-built substation at Tatogga Lake. In addition, BC Hydro has built a 16 km distribution line from Tatogga Lake Substation to the community of Iskut. The total cost represents the gross costs of the project and has not been netted to reflect the contribution from the customer towards the construction of the transmission line. The total cost increased from $180M to $209M to reflect a higher cost for the transmission line.
BC Hydro purchased the transmission line upon completion by the customer at a fixed cost. The

additional cost of the line, including the cost increase, was paid for by the customer and the net cost to BC Hydro for the project has not increased.

Ongoing and Planned

(All costs are expressed in millions) (Life to Date costs as of December 31, 2014)

Merritt Area Transmission Project

2015 Targeted completion **$65 Total cost** **$42 Life to Date (LTD) cost**

Construct a new 138 kV transmission line between the Merritt and Highland substations, expand the Merritt Substation and add new equipment at the Highland Substation to meet the increased demand for power in the Merritt area.

Dawson Creek/Chetwynd Area Transmission Project

2015 Targeted completion **$296 Total cost** **$183 LTD cost**

The project will expand the Peace Region 230 kV transmission system to the Dawson Creek/Chetwynd Area to supply the area's load growth. The solution will include the construction of new 230 kV lines between Dawson Creek and Bear Mountain Terminal (BMT), and from BMT to a new substation called Sundance Lake Substation, located approximately 19 km east of Chetwynd. The total cost forecast increased from the 2013/14-2015/16 Service Plan due to increases in cost estimates for labour and materials and additional project consultation requested by the BCUC. The total cost estimate is within the range provided in the project's CPCN application update provided to the BCUC in March 2012.

G.M. Shrum Units 1 to 5 Turbine Replacement

2015 Targeted completion **$272 Total cost** **$144 LTD cost**

Replace the Units 1 to 5 turbines to reduce the risk of runner failure, decrease maintenance costs and improve operating efficiency.

Long Beach Area Re-Inforcement

2015 Targeted completion **$56 Total cost** **$22 LTD cost**

Expansion of Long Beach and Great Central Lake substations with two new transformers at each and capacitor banks at Long Beach to support the load growth and provide voltage support in the area.

Surrey Area Substation Project

2015 Targeted completion **$94 Total cost** **$39 LTD cost**

Construct a new 200 MVA 230/25 kV substation in the Fleetwood area of Surrey. The station will be supplied from the adjacent 230 kV transmission line and will allow for future expansion to 400 MVA to service high load growth in the Fraser Valley West area. Construction of this new Fleetwood Substation will also allow for the decommissioning of 4 ageing substations in the Surrey/Langley area.

Interior to Lower Mainland Project

2015 Targeted completion **$725 Total cost** **$574 LTD cost**

Construct a new 500 kV transmission line, approximately 247 km in length, between the Nicola Substation near Merritt and the Meridian Substation in Coquitlam and build a new series capacitor station at Ruby Creek near Agassiz to help meet domestic load growth in the Lower Mainland.

Smart Metering & Infrastructure Program

2015 Targeted completion **$930 Total cost** **$721 LTD cost**

The Smart Metering and Infrastructure Program includes the installation of 1.9 million smart meters in homes and businesses across the province, an advanced telecommunications infrastructure to support electricity system management and customer applications, and information technology to support customer billing, load forecasting and outage management systems.

Smart Metering & Infrastructure Program amount includes both capital costs and operating expenditures subject to regulatory deferral.

Hugh Keenleyside Spillway Gate Reliability Upgrade

2015 Targeted completion **$123 Total cost** **$87 LTD cost**

Upgrade the spillway gates at the Hugh Keenleyside Dam to increase public and employee safety by ensuring the gates meet flood discharge reliability requirements.

Spillway gates control the amount of water that can be discharged from the reservoir. They are generally used in times of flood to pass high inflows.

Upper Columbia Capacity Additions at Mica – Units 5 & 6

2015 Targeted completion **$714 Total cost** **$486 LTD cost**

Install two additional 500 MW generating units into existing unit bays at the Mica Generating Station. The new units are similar to the four existing units, but with more efficient turbines.

Big Bend Substation

2017 Targeted completion **$56 Total cost** **$18 LTD cost**

The South Burnaby, Big Bend area requires a new, 100 MVA, 69/12 kV Substation to meet local residential and commercial load growth.

Ruskin Dam Safety and Powerhouse Upgrade

2017 Targeted completion **$748 Total cost** **$283 LTD cost**

Improve seismically deficient dam and rehabilitation/replacement of powerhouse equipment that was brought into service between 1930 and 1950. The project includes: reinforcement of the right embankment; seismic upgrade of the dam and water intakes; powerhouse upgrades; and, relocation of the switchyard. Once completed, the upgraded facility will be reliable and safe and will produce enough electricity to serve more than 33,000 homes.

John Hart Generating Station Replacement

2019 Targeted completion **$1,093 Total cost** **$239 LTD cost**

Replace the existing six-unit 126 MW generating station (in operation since 1947) and add integrated emergency bypass capability to ensure reliable long-term generation and to mitigate earthquake risk and environmental risk to fish and fish habitat.

Cheakamus Unit 1 and Unit 2 Generator Replacement

2019 Targeted completion **$74 Total cost** **$4 LTD cost**

Replace the two generators at Cheakamus generating station (commissioned over 50 years ago) to address the poor condition and known deficiencies. Replacing the generators will increase the capacity of each unit from 70 MW to 90 MW.

Site C Clean Energy Project

2024* Targeted completion **$8,335** Total cost** **$415 (deferred capital) LTD cost**

Site C will be a third dam and hydroelectric generating station on the Peace River approximately seven kilometres southwest of Fort St. John. It will be capable of producing approximately 5,100 gigawatt-hours of electricity annually and 1,100 megawatts of capacity. Site C project was approved by the Provincial Government in December 2014. Site C will provide clean, renewable and cost-effective power in B.C. for more than 100 years.

**Planned in-service date for all units. This timeline reflects the project's current schedule and is subject to change based on a review of the construction schedule.*

***Site C forecast and life-to-date amounts include both capital costs and expenditures subject to regulatory deferral. Total cost excludes the Project Reserve of $440 million (established by Government to account for events outside of BC Hydro's control that could occur during construction) which is held by the Treasury Board. The increase to the 2010 capital cost estimate from $7,900 million to $8,335 million reflects costs associated with the change from the harmonized sales tax to the provincial sales tax, and a revised construction start date from January 2015 to summer 2015.*

Contemplated Projects over $50 million

Bridge River 2 Units 5 and 6 Upgrade

The Bridge River 2 generating Units 5 and 6 are rated as unsatisfactory and have been de-rated from 71MW to 48MW. This project will restore the capacity and reliability of the Unit 5 and 6 generators as well as the reliability of other major components.

Bridge River 2 Units 7 and 8 Upgrade

The Bridge River 2 generating Units 7 and 8 are rated as unsatisfactory and have been de-rated from 71MW to 62MW. This project will restore the capacity and reliability of the Unit 7 and 8 generators as well as the reliability of other major components.

Clowhom Unit Upgrade

Major components of the Clowhom generating unit are in unsatisfactory or poor condition. This project will address issues with the generating unit in order to maintain reliability and reduce the risk of forced outages at the Clowhom facility.

Downtown Vancouver Electricity Supply Plan

Upgrade and expand the transmission and distribution network serving downtown Vancouver over the next 20 to 30 years to improve reliability and seismic resiliency. Several projects will be identified in the plan including the addition of a new transmission cable coming into the downtown core, the construction of new substations, and the refurbishment and/ or replacement of the existing substations. The project also includes converting the existing distribution system from a 12 kV dual radial system to a 25 kV open-loop system. This program appeared in the 2014/15–2016/17 Service Plan as the Downtown Vancouver Redevelopment Program.

G.M. Shrum G1-G10 Control System Upgrade

The condition of the legacy controls for GMS generating units, which were originally installed in the 1960s and 1970s, is of growing concern due to increasing maintenance requirements, lack of spare parts availability and decreasing reliability. The controls are well beyond their expected life, cause operating problems and increase the risk of damage to major equipment.

Horne Payne Substation Upgrade

Expand the Horne Payne Substation with the addition of two 230/25kV, 150MVA transformers, gas-insulated (GIS) feeder sections, and a new control building. This project will increase the firm capacity of the substation, add needed feeder positions, facilitate the gradual conversion of the area supply voltage from 12kV to 25kV, and allow for the implementation of an open-loop distribution system.

John Hart Dam Seismic Upgrade

Upgrade the John Hart Dam to reliably withstand moderate to severe earthquake loadings and meet normal operations criteria post-earthquake.

Ladore Dam Spillway Gates Upgrade

Reduce the risk of failure of the spillway gates and hoist structure due to a seismic event. Improve post-seismic operability in order to prevent the subsequent uncontrolled release of water into the downstream John Hart Reservoir and maintain reservoir control in the system.

Metro North System Supply Reinforcement

Add new 230 kV transmission line(s) between Coquitlam and Vancouver to address load growth in the Metro Vancouver area and to strengthen the reliability of the network.

Northwest Substation Upgrades Project

Carry out modifications, upgrades and additions to five substations in the northwest (Williston, Glenannan, Telkwa, Skeena and Minette) to accommodate the interconnection of industrial loads in the northwest, including Shell's LNG Canada Liquefied Natural Gas facility expected to come on line in early 2020.

Peace Region Electric Supply

Increase transmission capacity to the South Peace area by providing a second 230 kV supply to Dawson Creek in response to the significant load growth in the area, mainly from the gas production industry.

Prince George to Terrace Capacitors

Increase the capacity of the 500kV circuit supplying the north coast areas. This will increase the transfer capacity by up to approximately 60 per cent through the addition of reactive compensation. This additional capacity is required to provide capacity for industrial loads expected to interconnect to in the northwest, including Shell's LNG Canada's Liquefied Natural Gas plant that is scheduled for early 2020.

Revelstoke Improve Left Bank Slope Stability

This project will improve the stability of the left bank slope, adjacent to the dam and powerhouse, to reduce the potential for slides or rock fall to impact the penstocks and powerhouse.

Revelstoke Unit 6 Installation

Supply and install a 500 MW unit in the existing empty Unit 6 bay at Revelstoke Generating station to add capacity to the BC Hydro system. Revelstoke Unit 6 is identified as a contingency resource in BC Hydro's 2013 Integrated Resource Plan (IRP).

Seven Mile Unit 1-3 Turbines Overhaul

This project will perform a major overhaul of the Unit 1-3 turbines, installed in 1979 and 1980, in order to address condition issues and extend the life of the turbine.

Strathcona Dam Spillway Upgrade

Upgrades to the Strathcona Dam spillway will provide reservoir retention and post-seismic operability; as well as reliability of the spillway gates for flood passage capability.

Strathcona Dam Discharge Upgrade

This project will provide deep reservoir drawdown capability, as a first line of defense against uncontrolled release of the reservoir, resulting from damage to the dam caused by an earthquake or other Dam Safety events such as increased seepage through the earth fill dam, and to facilitate a future dam upgrade project and decommissioning of the existing low level outlet beneath the dam.

Terrace – Kitimat Transmission Project

Replace the existing transmission line serving the Kitimat area that has reached the end of its serviceable life. This project would replace the 60km transmission line that runs between Skeena and Minette substations and the 3km transmission line that runs between Minette and Kitimat substations with new lines on a new right of way. Both of these lines have been de-rated due to defects and deficiencies, and cannot supply current and forecast load demands.

W.A.C. Bennett Dam Rip-Rap Upgrade

The W.A.C. Bennett Dam rip-rap has degraded since its completion in 1968. The project will rebuild the upstream slope to ensure there is adequate protection and shielding to the embankment dam from the wind generated waves.

Appendix C:

Subsidiaries and Operating Segments

Active Subsidiaries

BC Hydro has created or retained a number of other subsidiaries for various purposes, including to hold licenses in other jurisdictions, to manage real estate holdings and to manage various risks.

Powerex Corp.

Powerex Corp. is a wholly-owned subsidiary of BC Hydro and a key participant in energy markets across North America, buying and supplying wholesale power, renewable energy, natural gas, ancillary services, and financial energy products and services. Established in 1988, its export, marketing and trade activities help manage BC Hydro's electric system resources and provide significant economic benefits to British Columbia.

Powerex supports BC Hydro's electric system requirements through importing and exporting energy as required in addition to meeting its own trade commitments. Powerex also markets, on behalf of the Province, the Canadian Entitlement to the Downstream Benefits of the Columbia River Treaty.

The Chief Executive Officer (CEO) of Powerex reports directly to the Board of Directors of Powerex through the Chair of Powerex and works closely with the President & CEO of BC Hydro as a member of the Executive Team. The Chair of the Powerex Board, the Powerex CEO and BC Hydro's Chief Executive Officer (who is also a member of the Powerex Board), ensure the Board of BC Hydro is informed of Powerex's key strategies and business activities.

Powerex operates in complex and volatile energy-markets, which can cause net income in any given year to vary significantly. Market and economic conditions, reduced BC Hydro system flexibility, income timing differences and the strength of the Canadian dollar can materially impact Powerex net income. Over the previous five years, Powerex income has ranged from $8 to $142 million (fiscal 2010 to fiscal 2014). The Service Plan forecast includes annual net income from Powerex of approximately $100 million per year for fiscal 2016 to fiscal 2018. For more information, visit powerex.com.

Powertech Labs Inc.

Powertech Labs, operating in Surrey since its inception in 1979, is a wholly-owned subsidiary of BC Hydro. Powertech is internationally recognized as holding expertise in various fields of operation, and provides research and development, testing, technical services and advanced technology services to the international energy community including BC Hydro.

Powertech's revenue in fiscal 2014 was $30 million with a net income of $3.8 million. The forecasted revenue for fiscal 2015 is $31 million with a net income of $4.5 million. The Service Plan forecast includes annual net income from Powertech ranging from $4 million to $6 million for fiscal 2016 to fiscal 2018. For more information, visit powertechlabs.com.

All the staff and management needs of the active subsidiaries below are fulfilled by BC Hydro employees, who perform these duties without additional remuneration. Three of these subsidiaries are considered active:

BCHPA Captive Insurance Company Ltd
Procures insurance products and services on behalf of BC Hydro.

Columbia Hydro Constructors Ltd
Administers and supplies the labour force to specified projects.

Tongass Power and Light Company
Provides electrical power to Hyder, Alaska due to its remoteness from the Alaska electrical system.

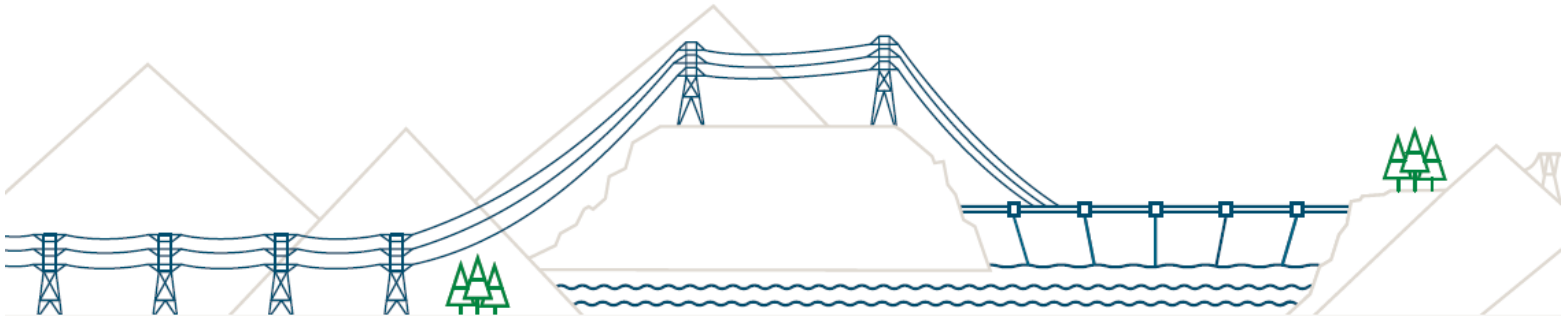
Nominee Holding Companies and/or Inactive/Dormant Subsidiaries

BC Hydro's remaining subsidiaries either serve as nominee holding companies (indicated with an *) or are considered to be inactive/dormant. The inactive/dormant subsidiaries do not carry on active operations. As of December 31, 2014, these other subsidiaries consisted of the following:

1. BCH Services Asset Corp.
2. British Columbia Hydro International Limited
3. British Columbia Power Exchange Corporation
4. British Columbia Power Export Corporation
5. British Columbia Transmission Corporation
6. Columbia Estate Company Limited*
7. Edgewood Water Corporation
8. Edmonds Centre Developments Limited*
9. Fauquier Water and Sewage Corporation
10. Hydro Monitoring (Alberta) Inc.*
11. Waneta Holdings (US) Inc.*

Residential 10pt CSAT

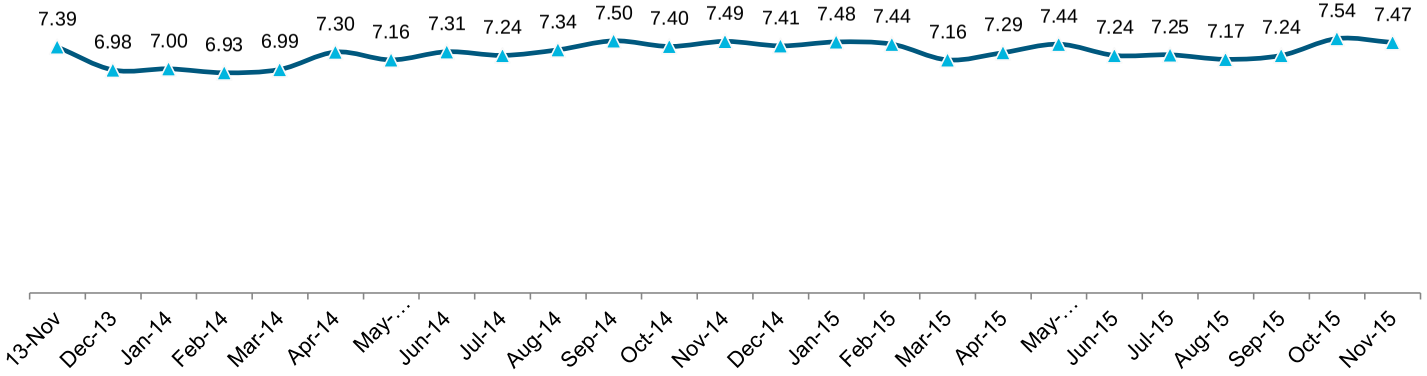
Research & Analytic Services



November 2015

BC Hydro
Power smart

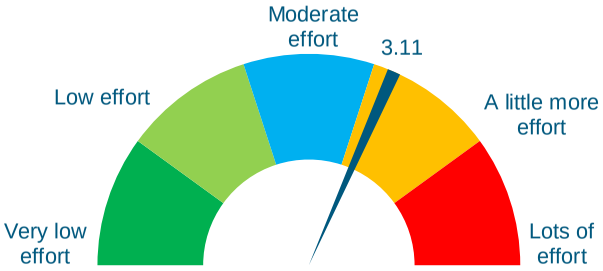
RESIDENTIAL CSAT – OVERALL SCORE



- Overall satisfaction decreased by 1% in November.
- Satisfaction in the North and Vancouver Island experienced 7% increases in November.

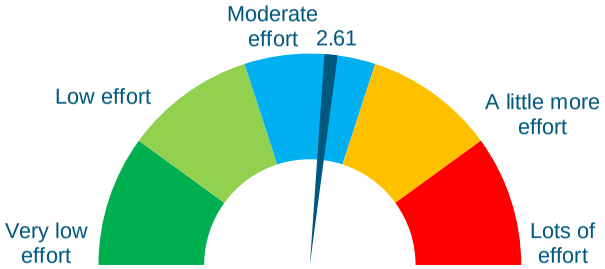
Customer Effort Score…

Call Centre

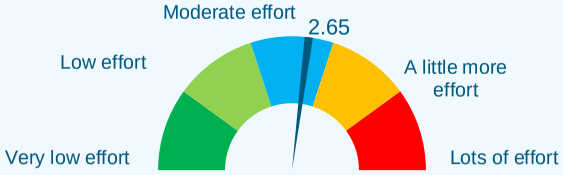


- 22% indicate their dealing involved very little effort.
- 24% note their dealing involved lots of effort.
- 52% indicate low to some effort

Online

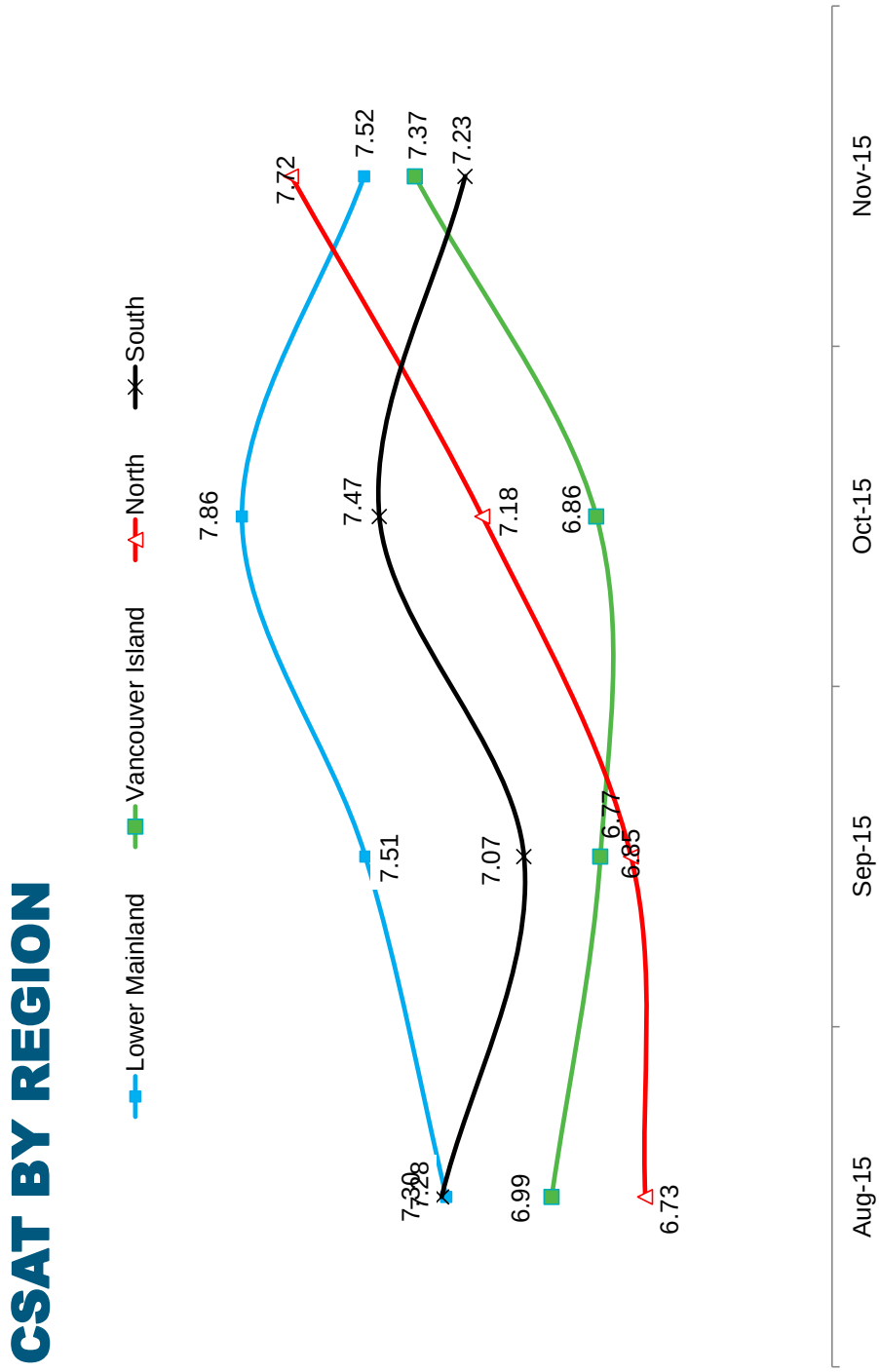


- 32% indicate their dealing involved very little effort.
- 13% note their dealing involved lots of effort.
- 52% indicate low to some effort



- 25% indicate their dealing involved very little effort.
- 11% note their dealing involved lots of effort.
- 64% indicate low to some effort

Overall similar results are observed in the monthly Corporate Reputation tracking survey. It should be noted though that the survey does not take channel into account.

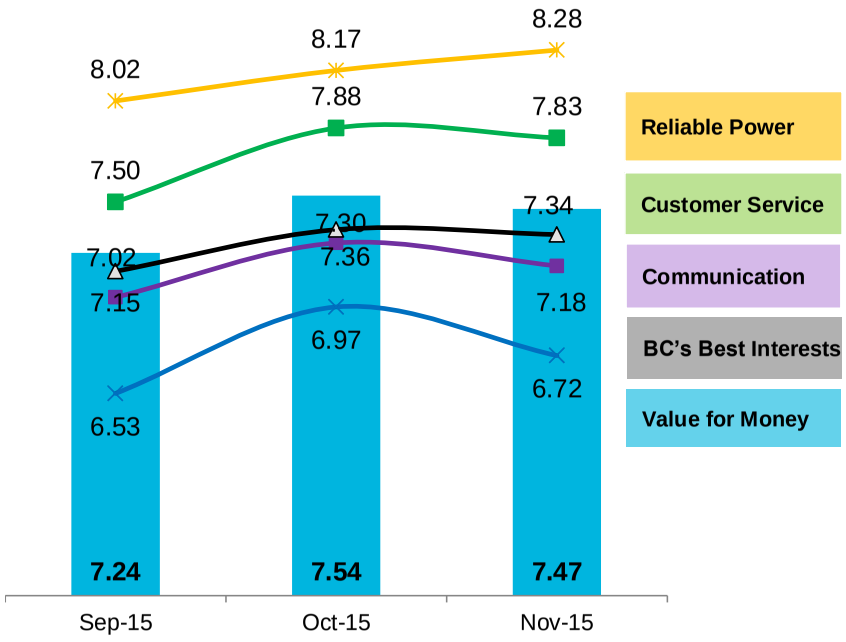

CSAT BY REGION
Lower Mainland
Vancouver Island
North
South
7.86
7.51
7.30
7.28
7.72
7.52
7.47
7.07
7.18
7.37
7.23
6.99
6.86
6.77
6.85
6.73
Aug-15
Sep-15
Oct-15
Nov-15

Focus on

Key Drivers

BC Hydro
Power smart

TOP DRIVERS … DRIVING SATISFACTION



Key Observations

For the Residential CSAT tracking study, November saw three of the five drives dip somewhat.

The drivers which exhibited the most movement were:

- *Value for money* (-4.0%); and
- *Efforts to communicate (-2.0%).*

Detailed sub-driver satisfaction scores are shown on **Slide 8**.

Key Driver Scores (10 PT.)	% change compared to last month
Value for money	-4
Efforts to communicate	-2
Customer service	-1
Reliable power	1
Acting in BC's best interests	0

A DRIVER LOOK AT CSAT

Driver Satisfaction: Changes compared to last month	Previous Month	Current Month	% Change
The number of outages	7.99	8.15	2%
Providing reliable electricity	8.44	8.60	2%
The accuracy and clarity of BC Hydro's bills	7.83	7.96	2%
BC Hydro's efforts to offer info about conservation and energy efficiency through Power Smart program	7.67	7.77	1%
Speed in restoring power when outages occur	7.84	7.93	1%
The respect they show their customers	7.87	7.96	1%
BC Hydro's concern for public safety	8.24	8.33	1%
Being trusted to do the right things in the decisions or actions it takes	7.19	7.26	1%
Efforts to plan for the future energy needs of the province	7.05	7.11	1%
Their involvement in the community	6.92	6.96	1%
The friendliness and courteousness of BC Hydro's staff	8.23	8.26	0%
Good power quality, free from voltage fluctuations	8.43	8.43	0%
Acting in an open, transparent and accountable way	7.02	7.01	0%
Being easy to do business with	7.88	7.80	-1%
BC Hydro operating in an environmentally responsible manner	7.53	7.45	-1%
Having your problems taken care of on the first contact with BC Hydro	7.86	7.75	-1%
Their commitment to customer service	7.78	7.58	-3%
Their efforts to communicate with customers and communities	7.21	7.02	-3%
The stability of electricity prices	7.13	6.92	-3%
Providing helpful information on power outages, when they occur	7.73	7.50	-3%
The price you pay for electricity	6.72	6.49	-3%
Value for money	7.18	6.92	-4%
Acting in the best interests of British Columbians	7.16	6.87	-4%
The fairness of electricity prices	6.85	6.55	-4%
BC Hydro listening and acting on customer concerns	7.38	6.96	-6%

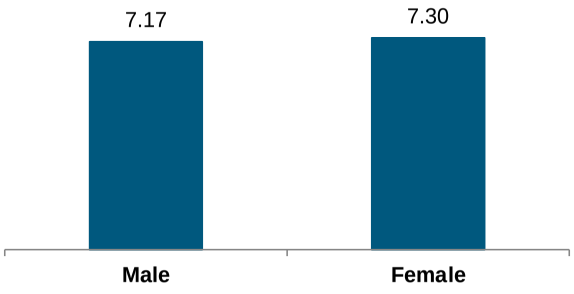
Focus on

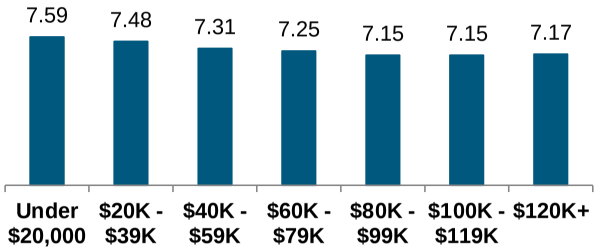
Key markets

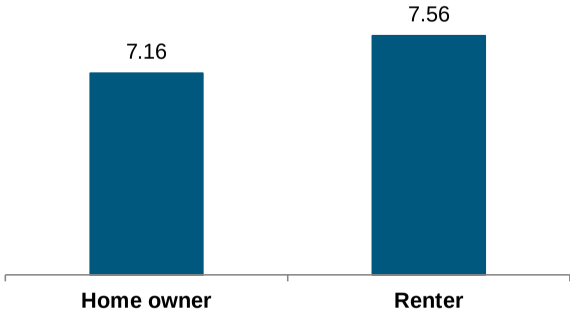
BC Hydro
Power smart

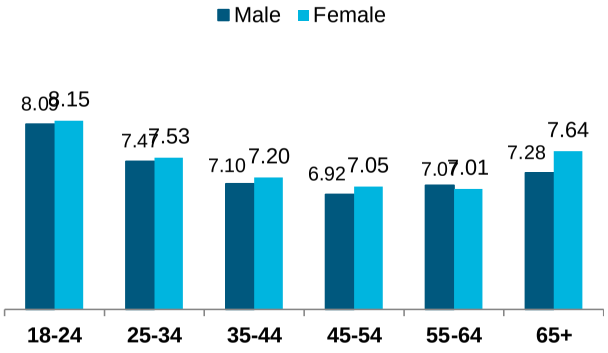
DEMOGRAPHIC BREAKDOWN

How satisfied are you with the overall service you have received from BC Hydro?









BC Hydro
Power smart

Collection Activity Indicators

Metric	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13
Active Residential Accounts Receivable	$141,767,413	$123,625,808	$113,042,485	$93,037,321	$87,042,876	$79,014,419	$66,140,342	$90,697,608	$109,193,738	$135,253,643	$158,346,726	$161,435,251
% of Active Residential Accounts Receivable > 60 days	4.6%	5.4%	6.1%	6.8%	6.4%	7.1%	6.5%	4.4%	4.6%	3.5%	3.2%	5.0%
Bad Debt - includes both residential and commercial accounts	$333,931	$390,583	$402,871	$538,072	$697,680	$561,950	$731,036	$786,744	$550,668	$830,229	$341,491	$616,966
Day Sales Outstanding	28.6	25.3	24.2	24.1	21.3	20.6	17.3	21.4	23.5	25.7	29.0	29.0
Active Reviews - for both residential and commercial accounts	10,807	10,679	9,483	8,032	7,331	6,632	7,380	7,366	5,558	11,711	7,719	4,419
Residential Accounts Receivable Closed	$30,296,290	$30,093,832	$30,958,511	$30,976,583	$30,760,841	$30,793,541	$30,320,801	$30,627,376	$30,890,612	$30,748,666	$31,100,254	$32,046,807

Metric	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14
Active Residential Accounts Receivable	$145,704,806	$133,966,974	$112,530,778	$90,296,352	$92,140,921	$82,009,659	$76,586,094	$90,961,238	$110,650,749	$157,455,738	$171,946,953	$173,122,768
% of Active Residential Accounts Receivable > 60 days	6.0%	6.1%	7.8%	8.1%	7.2%	7.4%	6.5%	5.3%	5.3%	3.7%	3.6%	5.1%
Bad Debt - includes both residential and commercial accounts	$604,269	$228,001	$311,282	$554,149	$479,726	$884,588	$684,103	$614,328	$999,938	$624,597	$431,032	$533,469
Day Sales Outstanding	26.6	25.3	23.3	19.5	21.2	19.5	18.4	20.3	23.3	29.0	31.0	30.6
Active Reviews - for both residential and commercial accounts	9,908	6,997	7,899	9,639	9,620	11,870	9,335	9,149	8,955	9,122	7,892	8,862
Residential Accounts Receivable Closed	$32,069,944	$32,357,929	$32,612,548	$32,481,476	$33,092,882	$33,345,344	$33,111,672	$33,616,436	$33,451,991	$33,311,340	$33,401,119	$33,824,335

Metric	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15
Active Residential Accounts Receivable	$145,980,927	$151,699,419	$123,345,309	$107,502,126	$101,020,665	$89,453,474	$84,132,563	$93,217,331	$103,348,916	$148,712,286	$154,600,910	$146,177,406
% of Active Residential Accounts Receivable > 60 days	6.4%	6.9%	8.0%	8.1%	7.4%	7.2%	5.9%	5.3%	4.8%	3.5%	3.2%	4.0%
Bad Debt - includes both residential and commercial accounts	$312,298	$323,180	$292,981	$448,478	$694,919	$807,430	$766,711	$616,006	$1,087,798	$543,190	$549,483	$766,373
Day Sales Outstanding	26.0	27.5	23.9	22.3	22.1	20.0	20.1	20.4	21.1	26.9	27.4	26.2
Active Reviews - for both residential and commercial accounts	11,171	8,367	8,066	8,233	7,679	7,409	7,668	7,068	8,157	8,441	6,880	8,100
Residential Accounts Receivable Closed	$33,701,040	$34,647,946	$35,809,006	$36,446,676	$37,147,854	$36,985,889	$36,884,922	$36,880,855	$36,469,505	$37,032,545	$37,182,867	$37,416,649

211.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.211.1 Please provide a copy of all reports, evaluations, memos, analyses or other written documents of any nature prepared since January 2010 establishing performance indicator targets to be met within the next year after publication of the performance targets; within the next two years after publication of the performance targets; or within the next three years after publication of the performance targets, with respect to:

(a) Debt prevention;
(b) Debt management;
(c) The treatment of vulnerable customers;
(d) Customer satisfaction.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.210.1.

212.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.212.1 Please provide a copy of all reports, evaluations, memos, analyses or other written documents of any nature prepared since January 2010 assessing, evaluating or otherwise discussing whether the one-, two- and/or three-year performance indicator targets identified in the response to the immediately preceding question were fulfilled, satisfied or otherwise achieved.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.210.1.

213.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.213.1 Please provide by month for each month January 2012 to present:

(a) The number of unpaid residential accounts turned over to third-party collection agencies for collection;
(b) The dollars of unpaid residential accounts turned over to third-party collection agencies for collection;
(c) The dollars of unpaid residential accounts actually collected by third party collection agencies;
(d) The percentage of unpaid residential dollars actually collected by third party collection agencies;
(e) The dollars of fees paid to third party collection agencies for the collection of unpaid residential accounts; and
(f) The percentage of collections / billings charged by third party collection agencies disaggregated by : (1) whether unpaid bills assigned to the agency are actually collected; or (2) whether unpaid bills assigned to the agency are not collected.

RESPONSE:

Please refer to Attachment 1 to this IR response for (a) (b) (c) (d) (e).

(f) BC Hydro does not pay extra fees to third-party collection agencies except for a commission based on the dollars collected. The commission paid to third-party agencies are provided in (e).

214.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.214.1 Please provide a copy of:

(a) The results of any call center satisfaction transactional research survey (e.g., "point-of-contact" survey, "moment of truth" survey) performed within the immediately preceding 36 months.
(b) A copy of the survey;
(c) A description of the survey methodology, including but not limited to the sample size, how the targets are selected, and the like.
(d) An explanation of how BC Hydro uses the results of this survey to improve service to its customers.

RESPONSE:

(a) Please refer to Attachment 1 to this IR response.

(b) Please refer to Attachment 2 to this IR response.

(c) BC Hydro's vendor, SQM Group, randomly selects at least three calls per agent from callers who successfully identified themselves in the IVR system, spoke with an agent and had a call reason code associated with the call. There are 500 to 700 surveys completed per month.

(d) The survey results are used for:

- **Management of Accenture's contractual performance;**
- **Formulating agent training methodology and content;**
- **Coaching for individual agents;**
- **Updating process documentation;**
- **Identifying trends, specifically areas customers expressed dissatisfaction; and**
- **Reviewing customers' direct feedback regarding BC Hydro's technologies (e.g., web, IVR), storm response and other areas for future improvements.**

SQM®™ Contact Channel FCR Experts

Using VoC Data to Benchmark, Track, Consult, Recognize and Improve Contact Center First Contact Resolution Performance

QTR 3 2015 Tracking Results

accenture

Accenture Utilities BPO Services
BC Hydro

Customer Satisfaction

Objective

From a customer perspective, this study benchmarks your contact center against 500 leading North American contact centers' FCR, Csat and CP SCORE™ performance, identifies repeat call reasons, provides proven best practices on reducing repeat calls and awards contact centers that have demonstrated FCR, Csat and CP SCORE™ excellence

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Customer Satisfaction

Methodology

- ***SQM Group*** identifies itself as the company conducting the survey on behalf of BC Hydro
- Telephone surveys for ***Quarter 3*** were conducted in ***July - September 2015*** and based on a recent call
- Call center first call resolution ***telephone survey*** was approximately ***4 - 5 minutes*** in length
- Call center first call resolution telephone survey was an in-depth survey approach consisting of ***15 - 22 questions***
- Quota was based on a random sampling of ***5 surveys/CSR per month***
- With a confidence level of 95% the margin of error based on the ***sample sizes*** is as follows:

Time Frame	Residential	Margin of Error	Commercial	Margin of Error	Total	Margin of Error
QTR 3 2015	1,400	(+/- 2.6%)	106	(+/- 9.5%)	1,506	(+/- 2.5%)
QTR 2 2015	1,591	(+/- 2.5%)	140	(+/- 8.3%)	1,731	(+/- 2.4%)
QTR 1 2015	1,752	(+/- 2.3%)	143	(+/- 8.2%)	1,895	(+/- 2.3%)
QTR 4 2014	1,621	(+/- 2.4%)	103	(+/- 9.7%)	1,724	(+/- 2.4%)
QTR 3 2014	1,805	(+/- 2.3%)	109	(+/- 9.4%)	1,914	(+/- 2.2%)
YTD 2015	4,743	(+/- 1.4%)	389	(+/- 5.0%)	5,132	(+/- 1.4%)

Note: Benchmark numbers have changed since last report

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Customer Reporting Framework

- KPI Dashboard
- Call Handling
- Csat Metrics
- Repeat Calls
- Customer Protection

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KPI Dashboard

8 Key Performance Indicators Benchmarking

Sample Size: YTD 2015 n=5,132

Note: Quartile Rankings are based on Average Call Center

Metric	Total YTD 2015	Average Energy	Best Energy	Average Call Center	Average World Class Call Center	Quartile Ranking
First Call Resolution	68%	72%	83%	70%	80%	3rd
Calls Resolved	88%	88%	95%	87%	94%	2nd
Avg. # Calls to Resolve	1.47	1.42	1.21	1.45	1.26	3rd
Call Center Csat	70%	72%	85%	75%	87%	4th
CSR Csat	78%	79%	90%	82%	91%	4th
CP SCORE™	68%	77%	83%	72%	85%	3rd
World Class Calls	65%	68%	81%	71%	83%	4th
Action Alert Calls	6%	6%	2%	6%	2%	3rd

First Call Resolution (FCR): % of customers who achieved call resolution in one call

Calls Resolved: % of customers whose call was resolved

Average Calls to Resolve (ACR): The average # of calls needed to resolve inquiry is based on total calls made

Call Center Csat: % of customers who are overall very satisfied (top box response) with their call center experience

CSR Csat: % of customers who are overall very satisfied (top box response) with the CSR who handled their call

CP SCORE™: % of customers who definitely would or probably would continue to use the organization's products or services, who are overall very satisfied (top box response) with their call center experience and their call was resolved

World Class Calls (WCC): % of customers who are overall very satisfied (top box response) with their call center experience, are very satisfied with the CSR who handled their call and their call was resolved

Action Alert Calls: % of customers who are overall somewhat dissatisfied or very dissatisfied with their call center experience and their call was unresolved

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KPI Dashboard

8 Key Performance Indicators
Industry Benchmarking

Metric	Total YTD 2015	Average Energy	Best Energy
First Call Resolution	68%	72%	83%
Calls Resolved	88%	88%	95%
Avg. # Calls to Resolve	1.47	1.42	1.21
Call Center Csat	70%	72%	85%
CSR Csat	78%	79%	90%
CP SCORE™	68%	77%	83%
World Class Calls	65%	68%	81%
Action Alert Calls	6%	6%	2%

Sample Size: YTD 2015 n=5,132

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KPI Dashboard

8 Key Performance Indicators

Residential Tracking

Time Frame	First Call Resolution	Calls Resolved	Avg. # Calls to Resolve	Call Center Csat	CSR Csat	CP SCORE™	World Class Calls	Action Alert Calls	Sample Size
QTR 3 2015	72%	89%	1.40	73%	81%	72%	69%	5%	1,400
QTR 2 2015	66%	87%	1.48	69%	77%	67%	64%	7%	1,591
QTR 1 2015	68%	89%	1.49	69%	78%	67%	65%	6%	1,752
QTR 4 2014	66%	87%	1.51	67%	75%	64%	62%	7%	1,621
QTR 3 2014	66%	88%	1.53	67%	77%	64%	62%	6%	1,805
QTR 2 2014	68%	89%	1.44	69%	76%	66%	63%	7%	1,792
QTR 1 2014	67%	86%	1.49	65%	74%	62%	61%	8%	2,260
QTR 4 2013	67%	86%	1.48	69%	75%	65%	63%	8%	2,329
YTD 2015	69%	88%	1.46	71%	79%	68%	66%	6%	4,743
2014	67%	87%	1.49	67%	76%	64%	62%	7%	7,455
2013	67%	87%	1.47	69%	76%	64%	63%	7%	9,369
2012	64%	85%	1.52	61%	71%	56%	56%	8%	7,808
2011	73%	89%	1.37	71%	78%	67%	65%	5%	8,244
2010	74%	89%	1.37	71%	78%	n/a	66%	5%	7,907
2009	75%	91%	1.33	73%	80%	n/a	68%	4%	7,956
2008	76%	91%	1.33	70%	82%	n/a	65%	4%	7,008
2007	72%	91%	1.42	66%	n/a	n/a	40%	4%	3,063

Note: Definition of World Class Calls has changed as of 2008

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KPI Dashboard

8 Key Performance Indicators

Commercial Tracking

Time Frame	First Call Resolution	Calls Resolved	Avg. # Calls to Resolve	Call Center Csat	CSR Csat	CP SCORE™	World Class Calls	Action Alert Calls	Sample Size
QTR 3 2015	60%	87%	1.56	65%	76%	61%	60%	8%	106
QTR 2 2015	65%	87%	1.51	67%	74%	67%	61%	4%	140
QTR 1 2015	57%	78%	1.73	59%	66%	55%	55%	12%	143
QTR 4 2014	60%	88%	1.60	64%	78%	67%	60%	5%	103
QTR 3 2014	54%	81%	1.74	61%	73%	60%	57%	11%	109
QTR 2 2014	60%	79%	1.68	58%	68%	56%	53%	10%	112
QTR 1 2014	63%	83%	1.57	65%	69%	62%	60%	11%	131
QTR 4 2013	62%	83%	1.60	60%	66%	55%	52%	6%	125
YTD 2015	61%	84%	1.61	64%	72%	61%	59%	8%	389
2014	60%	83%	1.64	62%	72%	61%	58%	9%	452
2013	64%	85%	1.55	64%	70%	58%	57%	7%	538
2012	59%	83%	1.62	59%	70%	55%	54%	9%	1,430
2011	67%	87%	1.47	67%	74%	63%	61%	6%	1,436
2010	69%	89%	1.42	72%	77%	n/a	67%	5%	1,508
2009	69%	88%	1.45	69%	75%	n/a	62%	5%	1,912
2008	70%	88%	1.42	65%	79%	n/a	64%	5%	1,642
2007	65%	87%	1.51	62%	n/a	n/a	35%	5%	754

Note: Definition of World Class Calls has changed as of 2008

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8 Key Performance Indicators

Total Tracking

Time Frame	First Call Resolution	Calls Resolved	Avg. # Calls to Resolve	Call Center Csat	CSR Csat	CP SCORE™	World Class Calls	Action Alert Calls	Sample Size
QTR 3 2015	71%	89%	1.41	73%	80%	71%	68%	6%	1,506
QTR 2 2015	66%	87%	1.48	69%	77%	67%	64%	7%	1,731
QTR 1 2015	67%	88%	1.51	68%	77%	66%	64%	7%	1,895
QTR 4 2014	66%	87%	1.52	67%	75%	64%	62%	7%	1,724
QTR 3 2014	66%	88%	1.55	66%	77%	64%	62%	7%	1,914
QTR 2 2014	68%	88%	1.45	68%	76%	65%	63%	7%	1,904
QTR 1 2014	66%	86%	1.50	65%	74%	62%	61%	8%	2,391
QTR 4 2013	67%	86%	1.49	68%	74%	64%	62%	8%	2,454
YTD 2015	68%	88%	1.47	70%	78%	68%	65%	6%	5,132
2014	66%	87%	1.50	67%	75%	64%	62%	7%	7,907
2013	67%	87%	1.47	68%	76%	64%	63%	7%	9,907
2012	63%	84%	1.53	61%	71%	56%	56%	8%	9,238
2011	72%	89%	1.38	70%	77%	67%	64%	5%	9,680
2010	73%	89%	1.38	71%	78%	n/a	66%	5%	9,415
2009	74%	90%	1.35	72%	79%	n/a	67%	4%	9,868
2008	75%	91%	1.35	69%	82%	n/a	65%	4%	8,650
2007	71%	90%	1.44	65%	n/a	n/a	39%	4%	3,817

Note: Definition of World Class Calls has changed as of 2008

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8 Key Performance Indicators

Residential Tracking by Call Reason

Call Reason	Time Frame	First Call Resolution	Calls Resolved	Avg. # Calls to Resolve	Call Center Csat	CSR Csat	CP SCORE™	World Class Calls	Action Alert Calls	Sample Size
Billing Inquiry	YTD 2015	68%	88%	1.47	70%	78%	67%	66%	7%	1,572
	2014	65%	85%	1.50	65%	73%	61%	59%	9%	2,287
	2013	64%	82%	1.51	63%	72%	58%	57%	9%	3,069
Change of Tenant	YTD 2015	73%	92%	1.40	74%	80%	72%	69%	4%	1,386
	2014	73%	92%	1.41	73%	81%	71%	70%	4%	1,944
	2013	83%	97%	1.25	82%	88%	80%	78%	1%	2,072
Dunning	YTD 2015	69%	89%	1.44	68%	80%	66%	65%	7%	896
	2014	67%	89%	1.49	67%	75%	63%	62%	7%	1,669
	2013	68%	90%	1.49	69%	75%	64%	63%	6%	2,538
eCare	YTD 2015	70%	88%	1.42	71%	79%	72%	67%	8%	117
	2014	66%	87%	1.46	66%	78%	64%	65%	6%	155
PowerSmart	YTD 2015	67%	85%	1.41	81%	78%	80%	74%	7%	27
	2014	62%	76%	1.56	62%	75%	63%	59%	14%	71
	2013	65%	83%	1.42	68%	73%	65%	61%	9%	192
SMI	2014	42%	66%	2.04	34%	50%	41%	34%	26%	38
	2013	22%	42%	2.41	36%	36%	31%	26%	40%	50
Trouble	YTD 2015	60%	84%	1.60	67%	74%	66%	60%	7%	496
	2014	62%	85%	1.59	64%	72%	61%	58%	6%	847
	2013	55%	81%	1.58	66%	72%	61%	59%	9%	1,007
Other	YTD 2015	63%	85%	1.54	64%	74%	61%	59%	7%	242
	2014	57%	79%	1.66	59%	68%	54%	53%	11%	332
	2013	52%	74%	1.77	56%	66%	52%	49%	14%	441

Note: Sample sizes less than 25 are not reported out

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8 Key Performance Indicators

Commercial Tracking by Call Reason

Call Reason	Time Frame	First Call Resolution	Calls Resolved	Avg. # Calls to Resolve	Call Center Csat	CSR Csat	CP SCORE™	World Class Calls	Action Alert Calls	Sample Size
Billing Inquiry	YTD 2015	62%	81%	1.61	61%	71%	56%	57%	9%	129
	2014	50%	73%	1.79	55%	65%	51%	47%	15%	133
	2013	56%	78%	1.62	62%	68%	56%	53%	8%	165
Change of Tenant	YTD 2015	62%	86%	1.57	68%	74%	70%	63%	5%	111
	2014	69%	88%	1.51	74%	81%	72%	69%	7%	121
	2013	76%	98%	1.42	79%	79%	74%	72%	2%	125
Dunning	YTD 2015	57%	85%	1.63	61%	72%	56%	56%	10%	61
	2014	63%	88%	1.62	61%	69%	59%	58%	6%	104
	2013	70%	88%	1.47	61%	70%	57%	58%	6%	135
Trouble	YTD 2015	63%	87%	1.66	67%	73%	64%	63%	10%	52
	2014	58%	83%	1.57	50%	65%	52%	46%	8%	52
	2013	53%	72%	1.71	56%	63%	45%	47%	15%	68
Other	YTD 2015	52%	80%	1.42	56%	72%	46%	52%	8%	25
	2013	47%	83%	1.83	44%	64%	38%	42%	11%	36

Note: Sample sizes less than 25 are not reported out

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8 Key Performance Indicators

Total Tracking by Call Reason

Call Reason	Time Frame	First Call Resolution	Calls Resolved	Avg. # Calls to Resolve	Call Center Csat	CSR Csat	CP SCORE™	World Class Calls	Action Alert Calls	Sample Size
Billing Inquiry	YTD 2015	67%	87%	1.48	70%	78%	66%	65%	7%	1,701
	2014	64%	84%	1.52	64%	73%	60%	58%	9%	2,420
	2013	63%	82%	1.51	63%	72%	58%	57%	9%	3,234
Change of Tenant	YTD 2015	73%	91%	1.41	74%	80%	72%	69%	4%	1,497
	2014	73%	92%	1.41	73%	81%	71%	70%	5%	2,065
	2013	82%	97%	1.26	82%	87%	79%	77%	1%	2,197
Dunning	YTD 2015	68%	88%	1.46	68%	79%	66%	64%	7%	957
	2014	67%	89%	1.50	67%	75%	63%	62%	7%	1,773
	2013	68%	90%	1.49	68%	75%	63%	63%	6%	2,673
eCare	YTD 2015	69%	87%	1.46	70%	76%	72%	65%	8%	126
	2014	64%	88%	1.50	67%	78%	65%	64%	7%	168
PowerSmart	YTD 2015	69%	86%	1.38	83%	76%	81%	72%	7%	29
	2014	62%	77%	1.55	63%	75%	64%	60%	14%	73
	2013	66%	84%	1.41	67%	74%	64%	61%	9%	200
SMI	2014	42%	66%	2.04	34%	50%	41%	34%	26%	38
	2013	24%	43%	2.38	37%	37%	33%	27%	39%	51
Trouble	YTD 2015	60%	84%	1.60	67%	74%	66%	61%	8%	548
	2014	62%	85%	1.59	63%	72%	61%	57%	6%	899
	2013	55%	81%	1.59	65%	71%	60%	58%	9%	1,075
Other	YTD 2015	62%	85%	1.53	64%	74%	60%	58%	7%	267
	2014	57%	80%	1.66	60%	69%	56%	54%	11%	356
	2013	51%	74%	1.77	55%	66%	51%	48%	14%	477

Note: Sample sizes less than 25 are not reported out

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8 Key Performance Indicators
Residential QTR 3 2015 by Employee Tenure

Employee Tenure	First Call Resolution	Calls Resolved	Avg. # Calls to Resolve	Call Center Csat	CSR Csat	CP SCORE™	World Class Calls	Action Alert Calls	Survey Sample Size	Employee Sample Size
6 months or less	73%	91%	1.41	71%	80%	70%	66%	2%	128	9
6 months - 1 year	73%	87%	1.35	73%	85%	74%	72%	7%	142	12
1 - 2 years	77%	95%	1.31	77%	86%	79%	70%	2%	56	5
2 - 4 years	74%	90%	1.34	74%	83%	72%	70%	4%	315	32
4+ years	71%	89%	1.44	74%	79%	72%	69%	6%	753	77

Note: Employees may be included in more than one tenure grouping

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8 Key Performance Indicators
Commercial QTR 3 2015 by Employee Tenure

Note: Survey sample sizes less than 25 are not reported out

Employee Tenure	First Call Resolution	Calls Resolved	Avg. # Calls to Resolve	Call Center Csat	CSR Csat	CP SCORE™	World Class Calls	Action Alert Calls	Survey Sample Size	Employee Sample Size
4+ years	67%	90%	1.49	73%	81%	70%	69%	8%	52	32

Note: Employees may be included in more than one tenure grouping

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8 Key Performance Indicators
Total QTR 3 2015 by Employee Tenure

Employee Tenure	First Call Resolution	Calls Resolved	Avg. # Calls to Resolve	Call Center Csat	CSR Csat	CP SCORE™	World Class Calls	Action Alert Calls	Survey Sample Size	Employee Sample Size
6 months or less	72%	91%	1.40	71%	80%	69%	66%	2%	137	9
6 months - 1 year	74%	88%	1.34	72%	84%	73%	71%	7%	148	12
1 - 2 years	71%	91%	1.40	77%	83%	77%	69%	3%	70	5
2 - 4 years	72%	90%	1.36	72%	83%	70%	69%	4%	338	32
4+ years	71%	89%	1.44	74%	79%	72%	69%	6%	805	77

Note: Employees may be included in more than one tenure grouping

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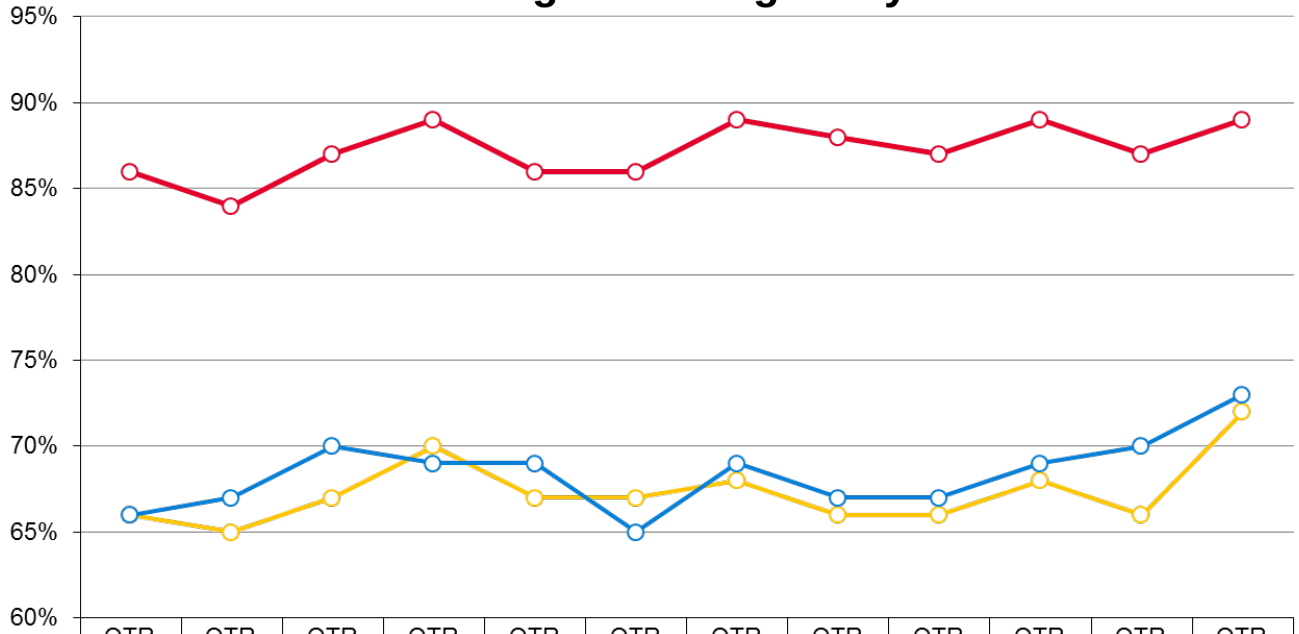
Key Performance Indicators

Residential Tracking - Trending Analysis



	QTR 4/12	QTR 1/13	QTR 2/13	QTR 3/13	QTR 4/13	QTR 1/14	QTR 2/14	QTR 3/14	QTR 4/14	QTR 1/15	QTR 2/15	QTR 3/15
First Call Resolution	66%	65%	67%	70%	67%	67%	68%	66%	66%	68%	66%	72%
Calls Resolved	86%	84%	87%	89%	86%	86%	89%	88%	87%	89%	87%	89%
Call Center Csat	66%	67%	70%	69%	69%	65%	69%	67%	67%	69%	70%	73%

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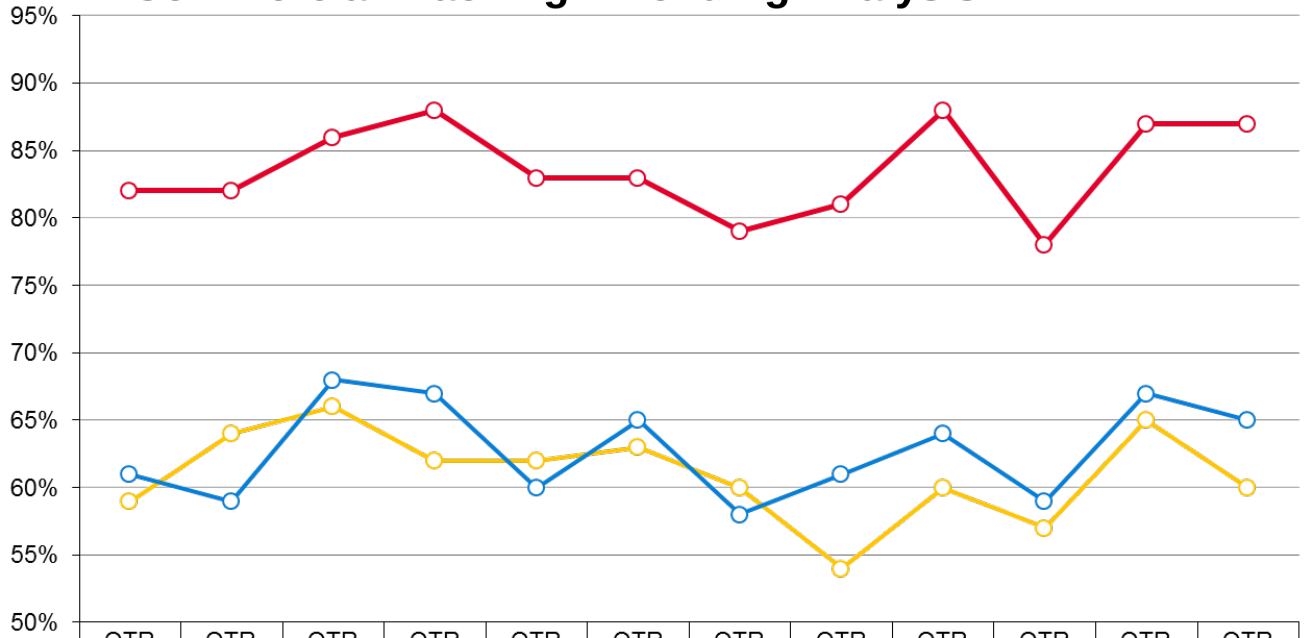
Key Performance Indicators

Commercial Tracking - Trending Analysis



	QTR 4/12	QTR 1/13	QTR 2/13	QTR 3/13	QTR 4/13	QTR 1/14	QTR 2/14	QTR 3/14	QTR 4/14	QTR 1/15	QTR 2/15	QTR 3/15
First Call Resolution	59%	64%	66%	62%	62%	63%	60%	54%	60%	57%	65%	60%
Calls Resolved	82%	82%	86%	88%	83%	83%	79%	81%	88%	78%	87%	87%
Call Center Csat	61%	59%	68%	67%	60%	65%	58%	61%	64%	59%	67%	65%

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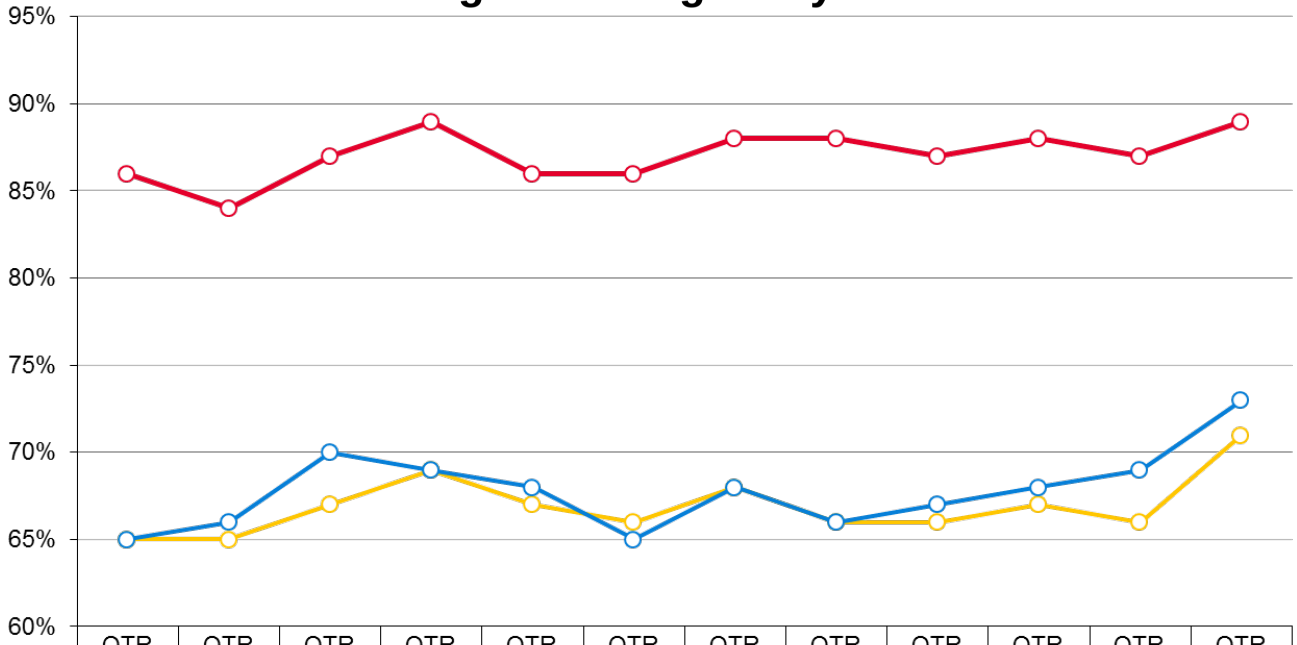
Key Performance Indicators

Total Tracking - Trending Analysis



	QTR 4/12	QTR 1/13	QTR 2/13	QTR 3/13	QTR 4/13	QTR 1/14	QTR 2/14	QTR 3/14	QTR 4/14	QTR 1/15	QTR 2/15	QTR 3/15
First Call Resolution	65%	65%	67%	69%	67%	66%	68%	66%	66%	67%	66%	71%
Calls Resolved	86%	84%	87%	89%	86%	86%	88%	88%	87%	88%	87%	89%
Call Center Csat	65%	66%	70%	69%	68%	65%	68%	66%	67%	68%	69%	73%

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Customer Reporting Framework

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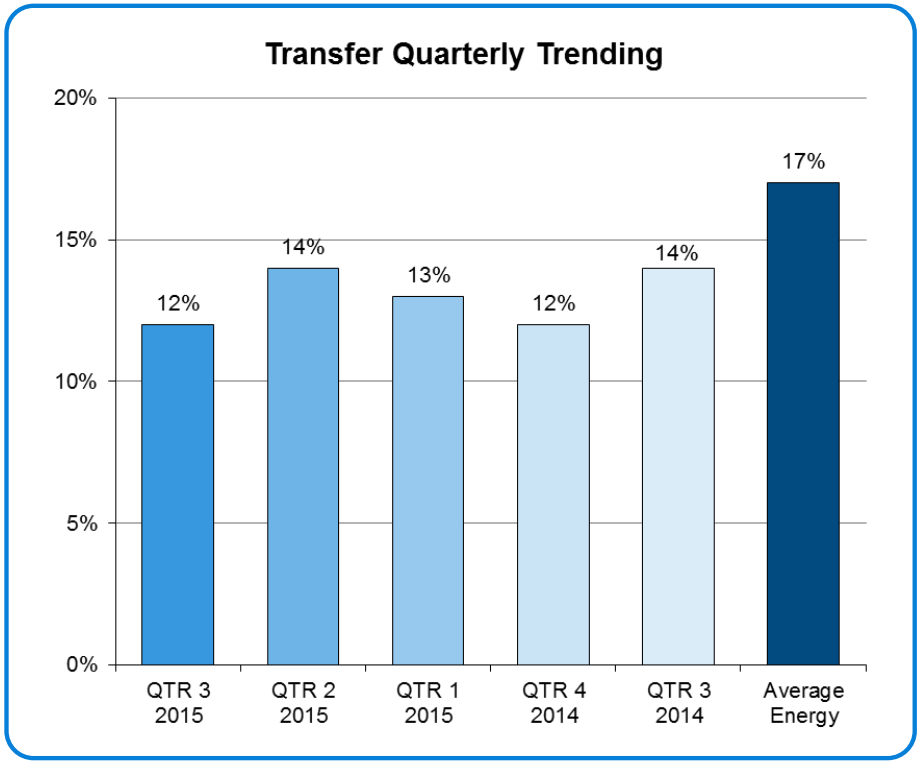
Call Handling

Transfer - Total

Benchmarking

Time Frame	Transfer
QTR 3 2015	12%
QTR 2 2015	14%
QTR 1 2015	13%
QTR 4 2014	12%
QTR 3 2014	14%
YTD 2015	13%
2014	12%
2013	11%
2012	11%
2011	12%
2010	11%
2009	12%
2008	11%
Average Energy	17%
Average Call Center	19%
Average World Class Call Center	15%



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Call Handling

Transfer
Tracking by LOB

Time Frame	Residential	Commercial	Total
QTR 3 2015	11%	27%	12%
QTR 2 2015	13%	18%	14%
QTR 1 2015	12%	18%	13%
QTR 4 2014	12%	13%	12%
QTR 3 2014	13%	24%	14%
YTD 2015	12%	21%	13%
2014	12%	16%	12%
2013	11%	11%	11%
2012	10%	13%	11%
2011	12%	13%	12%
2010	11%	11%	11%
2009	12%	11%	12%
2008	12%	10%	11%

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Customer Reporting Framework

- KPI Dashboard
- Call Handling
- Csat Metrics
- Repeat Calls
- Customer Protection

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Csat Metrics

Call Center Csat Top Box Summary

Tracking by LOB

Time Frame	Residential	Commercial	Total
QTR 3 2015	73%	65%	73%
QTR 2 2015	70%	67%	69%
QTR 1 2015	69%	59%	68%
QTR 4 2014	67%	64%	67%
QTR 3 2014	67%	61%	66%
YTD 2015	71%	64%	70%
2014	67%	62%	67%
2013	69%	64%	68%
2012	61%	59%	61%
2011	71%	67%	70%
2010	71%	72%	71%
2009	73%	69%	72%
2008	70%	65%	69%

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Csat Metrics

CSR Csat Tagging Tally Summary - Total
Benchmarking

Time Frame	# of Surveys Tagged	Total Tags	Overall Percentage	
			Positive	Negative
QTR 3 2015	1,414	3,386	89%	11%
QTR 2 2015	1,592	3,686	88%	12%
QTR 1 2015	1,757	3,995	88%	12%
QTR 4 2014	1,610	3,521	87%	13%
YTD 2015	4,763	11,067	88%	12%
Average Call Center	n/a	n/a	90%	10%
Average World Class Call Center	n/a	n/a	95%	5%

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Csat Metrics

CSR Csat Tagging Tally - Total

Positive Benchmarking

	QTR 3 2015		QTR 2 2015		QTR 1 2015		QTR 4 2014		YTD 2015		Average Call Center	
# of Surveys Tagged	1,414		1,592		1,757		1,610		4,763			
Total Tags	3,028	%	3,239	%	3,505	%	3,070	%	9,772	%		%
1. Understand Me	182	6%	227	7%	226	6%	207	7%	635	6%	595	6%
1a. Understand Reason for Call	70	2%	72	2%	80	2%	64	2%	222	2%	191	2%
1b. Clarity	77	3%	105	3%	105	3%	103	3%	287	3%	287	3%
1c. Listening	30	1%	35	1%	34	1%	37	1%	99	1%	92	1%
1d. Language	5	0%	15	0%	7	0%	3	0%	27	0%	25	0%
2. Help Me	1,349	45%	1,375	42%	1,467	42%	1,251	41%	4,191	43%	3,735	38%
2a. Helpful	247	8%	339	10%	347	10%	274	9%	933	10%	1,176	12%
2b. Knowledge	591	20%	539	17%	568	16%	514	17%	1,698	17%	1,125	12%
2c. Call Length	490	16%	470	15%	511	15%	436	14%	1,471	15%	1,300	13%
2d. Confidence	5	0%	8	0%	19	1%	12	0%	32	0%	69	1%
2e. Transfer	16	1%	19	1%	22	1%	14	0%	57	1%	52	1%
2f. Sales	0	0%	0	0%	0	0%	1	0%	0	0%	13	0%
3. Care About Me	499	16%	563	17%	590	17%	523	17%	1,652	17%	1,931	20%
3a. Greeting	7	0%	8	0%	2	0%	4	0%	17	0%	20	0%
3b. Build Rapport	439	14%	486	15%	528	15%	462	15%	1,453	15%	1,643	17%
3c. Empathy	27	1%	43	1%	37	1%	32	1%	107	1%	65	1%
3d. Appreciation	5	0%	8	0%	5	0%	4	0%	18	0%	72	1%
3e. Live Hold	9	0%	8	0%	10	0%	10	0%	27	0%	82	1%
3f. Trust	12	0%	10	0%	8	0%	11	0%	30	0%	49	1%
4. Resolve Me	998	33%	1,074	33%	1,222	35%	1,089	35%	3,294	34%	3,507	36%
4a. Resolution	879	29%	924	29%	1,069	30%	936	30%	2,872	29%	2,803	29%
4b. Authority	17	1%	30	1%	29	1%	14	0%	76	1%	54	1%
4c. Ownership	18	1%	14	0%	21	1%	13	0%	53	1%	238	2%
4d. Fair Treatment	7	0%	2	0%	1	0%	3	0%	10	0%	11	0%
4e. Summarizes Call	2	0%	0	0%	1	0%	6	0%	3	0%	17	0%
4f. Follow Through	8	0%	14	0%	20	1%	19	1%	42	0%	109	1%
4g. Next Steps	24	1%	31	1%	33	1%	52	2%	88	1%	131	1%
4h. Confirm Resolution	9	0%	8	0%	18	1%	6	0%	35	0%	45	0%
4i. Customer Sat	34	1%	51	2%	30	1%	40	1%	115	1%	99	1%

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Csat Metrics

CSR Csat Tagging Tally - Total

Negative Benchmarking

	QTR 3 2015		QTR 2 2015		QTR 1 2015		QTR 4 2014		YTD 2015		Average Call Center	
# of Surveys Tagged	1,414		1,592		1,757		1,610		4,763			
Total Tags	358	%	447	%	490	%	451	%	1,295	%		%
1. Understand Me	27	8%	29	6%	38	8%	52	12%	94	7%	136	11%
1a. Understand Reason for Call	8	2%	4	1%	7	1%	5	1%	19	1%	38	3%
1b. Clarity	11	3%	17	4%	23	5%	33	7%	51	4%	64	5%
1c. Listening	6	2%	5	1%	4	1%	6	1%	15	1%	18	1%
1d. Language	2	1%	3	1%	4	1%	8	2%	9	1%	16	1%
2. Help Me	126	35%	145	32%	147	30%	130	29%	418	32%	452	35%
2a. Helpful	46	13%	49	11%	47	10%	35	8%	142	11%	117	9%
2b. Knowledge	61	17%	71	16%	71	14%	65	14%	203	16%	184	14%
2c. Call Length	15	4%	16	4%	17	3%	25	6%	48	4%	97	7%
2d. Confidence	1	0%	5	1%	2	0%	1	0%	8	1%	19	1%
2e. Transfer	3	1%	2	0%	9	2%	4	1%	14	1%	30	2%
2f. Sales	0	0%	2	0%	1	0%	0	0%	3	0%	5	0%
3. Care About Me	47	13%	74	17%	76	16%	68	15%	197	15%	165	13%
3a. Greeting	0	0%	0	0%	2	0%	0	0%	2	0%	3	0%
3b. Build Rapport	41	11%	54	12%	57	12%	57	13%	152	12%	92	7%
3c. Empathy	4	1%	11	2%	10	2%	7	2%	25	2%	8	1%
3d. Appreciation	0	0%	1	0%	1	0%	0	0%	2	0%	10	1%
3e. Live Hold	0	0%	5	1%	3	1%	3	1%	8	1%	34	3%
3f. Trust	2	1%	3	1%	3	1%	1	0%	8	1%	18	1%
4. Resolve Me	158	44%	199	45%	229	47%	201	45%	586	45%	569	44%
4a. Resolution	96	27%	121	27%	147	30%	129	29%	364	28%	391	30%
4b. Authority	23	6%	28	6%	44	9%	32	7%	95	7%	36	3%
4c. Ownership	1	0%	3	1%	1	0%	2	0%	5	0%	19	1%
4d. Fair Treatment	1	0%	2	0%	2	0%	1	0%	5	0%	5	0%
4e. Summarizes Call	0	0%	0	0%	0	0%	0	0%	0	0%	4	0%
4f. Follow Through	5	1%	3	1%	5	1%	6	1%	13	1%	45	3%
4g. Next Steps	1	0%	7	2%	4	1%	7	2%	12	1%	20	2%
4h. Confirm Resolution	1	0%	1	0%	0	0%	1	0%	2	0%	5	0%
4i. Customer Sat	30	8%	34	8%	26	5%	23	5%	90	7%	44	3%

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Csat Metrics

Residential YTD 2015 Journey

Sample Size: Residential YTD 2015 n=4,743

Customer Most Important Metrics Ranking… → **Customer Very Satisfied Metrics Ranking…**

Ranking			
1	Call Resolution	0.69	*More Important*
2	Helpfulness	0.65	
3	Decision	0.65	↓
4	Cared	0.63	
5	Next Steps	0.62	
6	Knowledge	0.61	*Less Important*
7	Voice Menu	0.40	

Ranking			
1	Helpfulness	75%	*More Satisfied*
2	Call Resolution	72%	
3	Knowledge	71%	↓
4	Cared	70%	
5	Decision	69%	
6	Next Steps	50%	*Less Satisfied*
7	Voice Menu	35%	

	Gap
Decision	-2
Next Steps	-1
Call Resolution	-1
Cared	0
Voice Menu	0
Helpfulness	1
Knowledge	3

Customer most important metrics ranking are based on a statistical correlation between Call Center Csat and each service quality metric

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Csat Metrics

Commercial YTD 2015 Journey

Sample Size: Commercial YTD 2015 n=389

Customer Most Important Metrics Ranking… → **Customer Very Satisfied Metrics Ranking…**

Ranking			
1	Call Resolution	0.72	*More Important*
2	Decision	0.71	
3	Cared	0.68	↓
4	Helpfulness	0.67	
5	Knowledge	0.65	
6	Next Steps	0.64	*Less Important*
7	Voice Menu	0.49	

Ranking			
1	Helpfulness	67%	*More Satisfied*
2	Knowledge	64%	
3	Call Resolution	63%	↓
4	Cared	63%	
5	Decision	57%	
6	Next Steps	44%	*Less Satisfied*
7	Voice Menu	31%	

	Gap
Decision	-3
Call Resolution	-2
Cared	-1
Next Steps	0
Voice Menu	0
Helpfulness	3
Knowledge	3

Customer most important metrics ranking are based on a statistical correlation between Call Center Csat and each service quality metric

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Csat Metrics

Total YTD 2015 Journey

Sample Size: Total YTD 2015 n=5,132

Customer Most Important Metrics Ranking… → **Customer Very Satisfied Metrics Ranking…**

Ranking			
1	Call Resolution	0.70	*More Important*
2	Helpfulness	0.66	
3	Decision	0.66	
4	Cared	0.64	
5	Next Steps	0.62	
6	Knowledge	0.61	*Less Important*
7	Voice Menu	0.40	

Ranking			
1	Helpfulness	75%	*More Satisfied*
2	Call Resolution	71%	
3	Knowledge	71%	
4	Cared	69%	
5	Decision	68%	
6	Next Steps	50%	*Less Satisfied*
7	Voice Menu	34%	

	Gap
Decision	-2
Next Steps	-1
Call Resolution	-1
Cared	0
Voice Menu	0
Helpfulness	1
Knowledge	3

Customer most important metrics ranking are based on a statistical correlation between Call Center Csat and each service quality metric

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Csat Metrics

Residential Top Box Tracking Summary

Metrics	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD 2015	2014	2013	2012	2011	2010	2009	2008	2007
Sample Size	1,400	1,591	1,752	1,621	1,805	4,743	7,455	9,369	7,808	8,244	7,907	7,956	7,008	3,063
Opening:														
Voice Menu	36%	33%	35%	32%	36%	35%	37%	36%	31%	37%	37%	34%	32%	30%
Treating:														
Cared	73%	70%	67%	68%	66%	70%	67%	67%	63%	69%	66%	67%	65%	62%
Helpfulness	77%	75%	74%	73%	73%	75%	73%	73%	70%	74%	73%	74%	74%	72%
Resolving:														
Knowledge	74%	71%	69%	68%	68%	71%	67%	66%	62%	68%	66%	67%	67%	66%
Decision	72%	68%	66%	67%	67%	69%	66%	65%	60%	66%	65%	66%	66%	63%
Call Resolution	75%	72%	70%	70%	71%	72%	69%	68%	64%	71%	69%	71%	70%	69%
Next Steps	55%	50%	46%	47%	47%	50%	46%	44%	41%	45%	43%	45%	45%	44%

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Csat Metrics

Commercial Top Box Tracking Summary

Metrics	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD 2015	2014	2013	2012	2011	2010	2009	2008	2007
Sample Size	106	140	143	103	109	389	452	538	1,430	1,436	1,508	1,912	1,642	754
Opening:														
Voice Menu	33%	29%	31%	28%	30%	31%	33%	31%	31%	31%	31%	27%	28%	19%
Treating:														
Cared	70%	64%	57%	65%	62%	63%	61%	62%	61%	64%	62%	61%	58%	55%
Helpfulness	73%	71%	59%	75%	71%	67%	67%	70%	68%	70%	69%	68%	67%	63%
Resolving:														
Knowledge	68%	65%	59%	64%	65%	64%	61%	59%	58%	61%	61%	58%	58%	57%
Decision	67%	58%	50%	64%	62%	57%	60%	58%	57%	60%	60%	57%	55%	53%
Call Resolution	68%	69%	55%	70%	62%	63%	63%	62%	62%	64%	65%	62%	60%	60%
Next Steps	56%	49%	33%	55%	50%	44%	44%	40%	43%	42%	43%	40%	31%	37%

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Csat Metrics

Total Top Box Tracking Summary

Metrics	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD 2015	2014	2013	2012	2011	2010	2009	2008	2007
Sample Size	1,506	1,731	1,895	1,724	1,914	5,132	7,907	9,907	9,238	9,680	9,415	9,868	8,650	3,817
Opening:														
Voice Menu	36%	33%	34%	32%	36%	34%	36%	36%	31%	36%	36%	32%	31%	28%
Treating:														
Cared	72%	69%	67%	68%	66%	69%	66%	67%	63%	68%	65%	66%	64%	61%
Helpfulness	77%	75%	73%	73%	73%	75%	73%	73%	69%	74%	72%	73%	73%	71%
Resolving:														
Knowledge	73%	71%	68%	68%	68%	71%	67%	66%	61%	67%	65%	65%	65%	64%
Decision	71%	68%	65%	67%	67%	68%	65%	64%	60%	65%	64%	65%	64%	61%
Call Resolution	75%	71%	69%	70%	71%	71%	69%	68%	64%	70%	69%	70%	68%	67%
Next Steps	56%	50%	45%	47%	48%	50%	46%	44%	41%	44%	43%	44%	42%	42%

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Customer Reporting Framework

- KPI Dashboard
- Call Handling
- Csat Metrics
- Repeat Calls
- Customer Protection

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Repeat Calls

Repeat Call Reasons - Tier 1
Residential YTD 2015

Repeat Calls Frequency → **Repeat Calls** Satisfaction → **First Call Resolution** Targeted Opportunities

Ranking			
1	Verifying/Request	214	*Higher Frequency*
2	Call Center	183	
3	Billing	149	
4	CSR Approach	142	
5	Customer	127	
6	CSR Knowledge	117	
7	IVR	114	
8	CSR Information	79	
9	Call Length	76	
10	Policy	67	
11	Resolution	62	
12	Redirection	56	*Lower Frequency*
13	Products/Services	13	

Ranking			
1	Customer	70%	*More Satisfied*
2	Redirection	59%	
3	IVR	52%	
4	Verifying/Request	50%	
5	Call Center	49%	
6	Products/Services	46%	
7	Call Length	43%	
8	CSR Information	43%	
9	Billing	38%	
10	Policy	25%	
11	CSR Approach	20%	
12	CSR Knowledge	20%	*Less Satisfied*
13	Resolution	16%	

	Gap	
CSR Approach	-7	Fix 1st
CSR Knowledge	-6	
Billing	-6	
Verifying/Request	-3	Fix 2nd
Call Center	-3	
Resolution	-2	
CSR Information	0	Fix 3rd
Policy	0	
Call Length	2	
IVR	4	Fix 4th
Customer	4	
Products/Services	7	
Redirection	10	

Note: Other is not included

Sample Size: Residential YTD 2015 n=1,406

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Repeat Calls

Frequency - Tier 1 Main Reason

Residential Tracking

Tier 1	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD 2015	2014	2013	2012	2011	2010	2009	2008	2007
Sample Size	1,400	1,591	1,752	1,621	1,805	4,743	7,455	9,369	7,808	8,244	7,907	7,956	7,008	3,063
Repeat Call Frequency	377	498	531	520	568	1,406	2,313	2,788	2,566	2,065	1,841	1,775	1,594	832
Billing	26	49	74	59	68	149	308	403	358	279	296	289	176	86
Call Center	41	59	83	87	128	183	330	234	338	201	172	179	109	79
CSR Approach	33	55	54	33	44	142	223	237	170	118	92	103	138	62
Customer	49	35	43	44	47	127	226	322	217	252	210	266	305	138
Call Length	27	19	30	24	36	76	104	102	108	63	53	36	40	20
CSR Knowledge	31	44	42	43	51	117	199	217	175	90	77	64	96	46
CSR Information	23	24	32	29	34	79	170	276	195	144	166	167	109	51
IVR	31	39	44	40	22	114	133	142	92	105	79	84	111	86
Language	2	1	4	1	0	7	3	14	12	8	4	3	5	3
Policy	20	24	23	35	31	67	115	70	78	49	36	38	18	15
Verifying/Request	52	94	68	78	72	214	305	345	414	402	399	334	285	157
Resolution	21	25	16	15	14	62	75	282	275	238	171	127	166	77
Redirection	19	25	12	27	16	56	84	127	108	74	54	25	12	5
Products/Services	2	5	6	5	5	13	38	17	26	42	32	60	24	7

Note: Other is not included

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Repeat Calls

Satisfaction - Tier 1 Main Reason

Residential Tracking

Tier 1	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD 2015	2014	2013	2012	2011	2010	2009	2008	2007
Sample Size	1,400	1,591	1,752	1,621	1,805	4,743	7,455	9,369	7,808	8,244	7,907	7,956	7,008	3,063
Repeat Call Frequency	377	498	531	520	568	1,406	2,313	2,788	2,566	2,065	1,841	1,775	1,594	832
Billing	31%	49%	34%	29%	26%	38%	34%	35%	27%	34%	32%	40%	40%	33%
Call Center	56%	46%	48%	53%	48%	49%	50%	49%	44%	51%	53%	47%	50%	40%
CSR Approach	18%	24%	17%	24%	16%	20%	13%	17%	12%	14%	13%	19%	20%	19%
Customer	67%	69%	74%	66%	68%	70%	67%	63%	64%	67%	63%	74%	66%	69%
Call Length	48%	37%	43%	58%	47%	43%	52%	48%	38%	60%	36%	47%	38%	35%
CSR Knowledge	16%	20%	21%	23%	24%	20%	22%	20%	13%	18%	25%	20%	28%	17%
CSR Information	48%	50%	34%	34%	38%	43%	37%	39%	34%	46%	34%	39%	36%	18%
IVR	45%	49%	59%	40%	50%	52%	45%	43%	48%	43%	41%	30%	36%	29%
Language	50%	100%	50%	100%	0%	57%	100%	43%	33%	0%	25%	67%	20%	0%
Policy	15%	38%	22%	14%	23%	25%	20%	29%	18%	18%	44%	25%	39%	27%
Verifying/Request	50%	49%	50%	60%	49%	50%	54%	51%	45%	55%	54%	46%	54%	46%
Resolution	19%	16%	13%	20%	36%	16%	21%	22%	20%	20%	18%	22%	20%	22%
Redirection	58%	64%	50%	41%	25%	59%	33%	51%	34%	43%	44%	33%	17%	40%
Products/Services	50%	60%	33%	60%	0%	46%	34%	35%	15%	29%	31%	27%	38%	17%

Note: Other is not included

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Repeat Calls

Non-FCR - Tier 1 Main Reason

Residential Tracking

Tier 1	QTR 3 2015		QTR 2 2015		QTR 1 2015		QTR 4 2014		YTD 2015	
	Repeat Call Frequency	Non - FCR Percentage	Repeat Call Frequency	Non - FCR Percentage	Repeat Call Frequency	Non - FCR Percentage	Repeat Call Frequency	Non - FCR Percentage	Repeat Call Frequency	Non - FCR Percentage
	392	28%	530	33%	557	32%	550	34%	1,479	31%
Billing	26	1.9%	49	3.1%	74	4.3%	59	3.6%	149	3.1%
Call Center	41	2.9%	59	3.7%	83	4.8%	87	5.4%	183	3.8%
CSR Approach	33	2.4%	55	3.4%	54	3.1%	33	2.0%	142	3.0%
Customer	49	3.5%	35	2.2%	43	2.5%	44	2.7%	127	2.7%
Call Length	27	1.9%	19	1.2%	30	1.7%	24	1.5%	76	1.6%
CSR Knowledge	31	2.2%	44	2.7%	42	2.4%	43	2.7%	117	2.5%
CSR Information	23	1.6%	24	1.5%	32	1.8%	29	1.8%	79	1.7%
IVR	31	2.2%	39	2.4%	44	2.5%	40	2.5%	114	2.4%
Language	2	0.1%	1	0.1%	4	0.2%	1	0.1%	7	0.1%
Policy	20	1.4%	24	1.5%	23	1.3%	35	2.2%	67	1.4%
Verifying/Request	52	3.7%	94	5.9%	68	3.9%	78	4.8%	214	4.5%
Resolution	21	1.5%	25	1.6%	16	0.9%	15	0.9%	62	1.3%
Redirection	19	1.4%	25	1.6%	12	0.7%	27	1.7%	56	1.2%
Products/Services	2	0.1%	5	0.3%	6	0.3%	5	0.3%	13	0.3%
Other	15	1.1%	32	2.0%	26	1.5%	30	1.9%	73	1.5%

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Repeat Calls

Tier 2 Repeat Call Reasons

Residential Tracking

	Tier 1	Tier 2	SOE	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD Total 2015	Monthly Avg 2015	2014	2013
		Sample Size		1,400	1,591	1,752	1,621	1,805	4,743	527	7,455	9,369
		Repeat Call Frequency		377	498	531	520	568	1,406	156	2,313	2,788
Fix 1st	Approach	CSR Didn't Call Back	CSR	3	8	6	7	6	17	2	37	24
		Not Helpful/Caring	CSR	17	21	27	12	15	65	7	114	126
		CSR Lacked Authority	CSR/O	11	16	12	10	18	39	4	50	39
		No Confidence in CSR	CSR	0	3	1	1	4	4	0	8	21
		Rude	CSR	2	7	8	3	1	17	2	14	27
	Knowledge	Fix Problem	CSR	17	31	37	32	31	85	9	155	201
		Not Aware of Promo	CSR	1	0	0	0	0	1	0	0	0
		Products/Services	CSR	13	13	5	11	20	31	3	44	16
	Billing	Incorrect	Org	2	4	4	2	14	10	1	43	59
		Corrections Not Done	CSR/O	3	1	1	10	8	5	1	36	35
		Payment Related	Cust/O	19	29	53	34	38	101	11	157	207
		Bill Unclear	Org	0	5	2	5	3	7	1	26	31
		Explain Charges	CSR	2	10	14	8	5	26	3	46	71
Fix 2nd	Verify / Request	Verify/Check Status	Org	43	76	52	65	42	171	19	212	246
		Request Not Done	CSR/O	9	18	16	13	30	43	5	93	99
	Call Center	Closed	Org	15	16	20	13	16	51	6	55	85
		Wait Time - Too Long	Org	16	36	49	65	99	101	11	230	94
		Busy Signal	Org	4	0	9	2	5	13	1	15	16
		Computer System	Org	5	5	4	4	6	14	2	17	18
		Call Back/Again	Org	1	2	1	3	2	4	0	13	21
	Resolution	Unsatisfactory	CSR	20	21	13	15	10	54	6	65	269
		Not Treated Fairly	CSR/O	0	1	3	0	0	4	0	1	6
		Next Steps Not Clear	CSR	1	3	0	0	4	4	0	9	7

Note: Other is not included

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Repeat Calls

Tier 2 Repeat Call Reasons

Residential Tracking

	Tier 1	Tier 2	SOE	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD Total 2015	Monthly Avg 2015	2014	2013
		Sample Size		1,400	1,591	1,752	1,621	1,805	4,743	527	7,455	9,369
		Repeat Call Frequency		377	498	531	520	568	1,406	156	2,313	2,788
Fix 3rd	Information	Inconsistent	CSR	1	2	3	7	3	6	1	28	31
		Incomplete	CSR	15	13	14	13	19	42	5	85	164
		Incorrect	CSR	7	9	15	9	12	31	3	57	81
	Policy	Not Authorized User	Cust/O	10	7	10	8	11	27	3	35	32
		Credit	Cust/O	0	1	0	0	0	1	0	2	0
		Disagreement	Cust/O	10	16	13	27	20	39	4	78	38
	Call Length	Hold - Disconnected	CSR/O	6	10	25	16	21	41	5	62	71
		Hold - Too Long	CSR/O	18	8	5	7	13	31	3	37	21
		Call - Too Long	CSR/O	3	1	0	1	2	4	0	5	10
Fix 4th	IVR	Language Issue	Org	0	0	0	0	0	0	0	1	0
		Not Clear/No Proper Options	Org	17	27	29	25	14	73	8	75	89
		Didn't Recognize Voice	Org	2	3	0	2	1	5	1	6	3
		Too Many Options	Org	5	0	3	5	0	8	1	10	13
		Disconnected	Org	2	6	9	3	4	17	2	18	22
		Wrong Dept	Org	5	3	3	5	3	11	1	23	15
	Customer	Provide More Info	Cust	29	17	27	24	33	73	8	134	184
		Missed Appointment	Cust	0	0	0	0	0	0	0	0	0
		Error	Cust	14	10	14	16	10	38	4	62	95
		Decision/Changed Mind	Cust	6	8	2	4	4	16	2	30	43
	Products / Services	Tech Didn't Fix Problem	Org	0	1	1	2	1	2	0	12	10
		Not Satisfied	Org	2	4	5	3	4	11	1	26	7
	Redirection	Manufacturer	Org	0	0	0	0	0	0	0	0	1
		Competitor	Org	0	0	0	0	0	0	0	0	1
		Store	Org	2	2	1	0	2	5	1	3	3
		Internet	Org	5	5	3	2	6	13	1	18	19
		Other	Org	12	18	8	25	8	38	4	63	103
	Language	Barrier - Customer	Cust	0	1	0	0	0	1	0	0	3
		Barrier - CSR	CSR	2	0	4	1	0	6	1	3	11

Note: Other is not included

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Repeat Calls

Repeat Call Reasons - Tier 1
Commercial YTD 2015

Repeat Calls Frequency → **Repeat Calls Satisfaction** → **First Call Resolution Targeted Opportunities**

Ranking			
1	CSR Knowledge	20	Higher Frequency
1	Verifying/Request	20	
3	IVR	14	
4	CSR Approach	13	
4	Call Length	13	
6	Customer	12	
6	Call Center	12	
8	Billing	11	
8	CSR Information	11	
10	Policy	6	
11	Resolution	3	
11	Redirection	3	Lower Frequency
11	Products/Services	3	

Ranking			
1	Call Center	58%	More Satisfied
2	Customer	50%	
3	Billing	45%	
4	Verifying/Request	45%	
5	IVR	43%	
6	Call Length	38%	
7	CSR Information	36%	
8	Policy	33%	
9	CSR Approach	31%	
10	CSR Knowledge	30%	
11	Resolution	0%	
11	Redirection	0%	Less Satisfied
11	Products/Services	0%	

	Gap	
CSR Knowledge	-9	Fix 1st
CSR Approach	-5	
Verifying/Request	-3	
IVR	-2	Fix 2nd
Call Length	-2	
Resolution	0	
Redirection	0	
Products/Services	0	
CSR Information	1	Fix 3rd
Policy	2	
Customer	4	
Billing	5	Fix 4th
Call Center	5	

Note: Other is not included

Sample Size: Commercial YTD 2015 n=141

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Repeat Calls

Frequency - Tier 1 Main Reason

Commercial Tracking

Tier 1	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD 2015	2014	2013	2012	2011	2010	2009	2008	2007
Sample Size	106	140	143	103	109	389	452	538	1,430	1,436	1,508	1,912	1,642	754
Repeat Call Frequency	41	43	57	40	46	141	172	184	534	426	413	550	466	251
Billing	2	5	4	2	1	11	15	23	41	42	44	71	34	18
Call Center	3	5	4	9	7	12	26	26	71	34	26	49	30	11
CSR Approach	2	3	8	2	7	13	15	15	33	28	19	39	41	16
Customer	5	4	3	3	4	12	12	16	57	52	55	70	87	37
Call Length	5	3	5	3	3	13	10	6	27	11	9	12	10	4
CSR Knowledge	5	3	12	7	7	20	26	12	34	21	25	28	32	16
CSR Information	4	4	3	1	2	11	10	15	42	25	47	48	41	24
IVR	6	5	3	4	4	14	11	7	24	26	24	30	32	24
Language	0	0	0	0	0	0	0	0	0	2	0	0	2	0
Policy	2	2	2	0	2	6	11	3	16	11	9	12	10	6
Verifying/Request	4	7	9	7	9	20	25	34	97	85	98	116	87	65
Resolution	1	1	1	0	0	3	4	18	65	57	38	45	49	23
Redirection	1	0	2	2	0	3	4	6	21	26	16	8	3	2
Products/Services	1	1	1	0	0	3	3	3	6	6	3	22	7	5

Note: Other is not included

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Repeat Calls

Satisfaction - Tier 1 Main Reason

Commercial Tracking

Tier 1	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD 2015	2014	2013	2012	2011	2010	2009	2008	2007
Sample Size	106	140	143	103	109	389	452	538	1,430	1,436	1,508	1,912	1,642	754
Repeat Call Frequency	41	43	57	40	46	141	172	184	534	426	413	550	466	251
Billing	100%	40%	25%	50%	0%	45%	20%	26%	24%	26%	45%	32%	18%	6%
Call Center	67%	40%	75%	44%	43%	58%	50%	31%	41%	47%	62%	55%	27%	45%
CSR Approach	50%	0%	38%	50%	29%	31%	27%	7%	9%	11%	11%	33%	15%	25%
Customer	40%	75%	33%	67%	75%	50%	67%	75%	65%	65%	71%	71%	64%	65%
Call Length	40%	67%	20%	0%	67%	38%	50%	33%	37%	45%	44%	25%	40%	50%
CSR Knowledge	40%	33%	25%	0%	29%	30%	15%	0%	12%	24%	32%	25%	22%	25%
CSR Information	25%	75%	0%	0%	50%	36%	30%	47%	31%	36%	38%	33%	17%	25%
IVR	50%	40%	33%	25%	50%	43%	36%	29%	38%	46%	54%	40%	22%	21%
Language	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%
Policy	0%	100%	0%	0%	0%	33%	18%	0%	31%	18%	56%	33%	30%	17%
Verifying/Request	50%	43%	44%	43%	22%	45%	40%	47%	38%	56%	52%	50%	50%	48%
Resolution	0%	0%	0%	0%	0%	0%	0%	28%	15%	14%	21%	16%	16%	18%
Redirection	0%	0%	0%	100%	0%	0%	100%	33%	48%	42%	63%	25%	33%	50%
Products/Services	0%	0%	0%	0%	0%	0%	33%	33%	0%	67%	33%	27%	29%	20%

Note: Other is not included

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Repeat Calls

Non-FCR - Tier 1 Main Reason

Commercial Tracking

Tier 1	QTR 3 2015		QTR 2 2015		QTR 1 2015		QTR 4 2014		YTD 2015	
	Repeat Call Frequency	Non - FCR Percentage	Repeat Call Frequency	Non - FCR Percentage	Repeat Call Frequency	Non - FCR Percentage	Repeat Call Frequency	Non - FCR Percentage	Repeat Call Frequency	Non - FCR Percentage
	42	40%	49	35%	61	43%	41	40%	152	39%
Billing	2	1.9%	5	3.6%	4	2.8%	2	2.0%	11	2.8%
Call Center	3	2.9%	5	3.6%	4	2.8%	9	8.8%	12	3.1%
CSR Approach	2	1.9%	3	2.1%	8	5.6%	2	2.0%	13	3.3%
Customer	5	4.8%	4	2.9%	3	2.1%	3	2.9%	12	3.1%
Call Length	5	4.8%	3	2.1%	5	3.5%	3	2.9%	13	3.3%
CSR Knowledge	5	4.8%	3	2.1%	12	8.5%	7	6.8%	20	5.1%
CSR Information	4	3.8%	4	2.9%	3	2.1%	1	1.0%	11	2.8%
IVR	6	5.7%	5	3.6%	3	2.1%	4	3.9%	14	3.6%
Language	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Policy	2	1.9%	2	1.4%	2	1.4%	0	0.0%	6	1.5%
Verifying/Request	4	3.8%	7	5.0%	9	6.3%	7	6.8%	20	5.1%
Resolution	1	1.0%	1	0.7%	1	0.7%	0	0.0%	3	0.8%
Redirection	1	1.0%	0	0.0%	2	1.4%	2	2.0%	3	0.8%
Products/Services	1	1.0%	1	0.7%	1	0.7%	0	0.0%	3	0.8%
Other	1	1.0%	6	4.3%	4	2.8%	1	1.0%	11	2.8%

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Repeat Calls

Tier 2 Repeat Call Reasons

Commercial Tracking

	Tier 1	Tier 2	SOE	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD Total 2015	Monthly Avg 2015	2014	2013
		Sample Size		106	140	143	103	109	389	43	452	538
		Repeat Call Frequency		41	43	57	40	46	141	16	172	184
Fix 1st	Knowledge	Fix Problem	CSR	3	1	11	4	6	15	2	21	11
		Not Aware of Promo	CSR	0	0	0	0	0	0	0	0	0
		Products/Services	CSR	2	2	1	3	1	5	1	5	1
	Approach	CSR Didn't Call Back	CSR	0	0	1	0	0	1	0	0	4
		Not Helpful/Caring	CSR	1	1	1	0	2	3	0	5	9
		CSR Lacked Authority	CSR/O	1	1	4	0	4	6	1	5	1
		No Confidence in CSR	CSR	0	1	0	0	0	1	0	1	1
		Rude	CSR	0	0	2	2	1	2	0	4	0
	Verify / Request	Verify/Check Status	Org	4	6	6	5	5	16	2	17	25
		Request Not Done	CSR/O	0	1	3	2	4	4	0	8	9
Fix 2nd	IVR	Language Issue	Org	0	0	0	0	0	0	0	0	0
		Not Clear/No Proper Options	Org	2	3	3	2	3	8	1	6	3
		Didn't Recognize Voice	Org	0	0	0	0	1	0	0	1	0
		Too Many Options	Org	0	1	0	1	0	1	0	1	2
		Disconnected	Org	1	0	0	1	0	1	0	3	1
		Wrong Dept	Org	3	1	0	0	0	4	0	0	1
	Call Length	Hold - Disconnected	CSR/O	2	2	3	1	3	7	1	5	4
		Hold - Too Long	CSR/O	2	1	2	2	0	5	1	5	1
		Call - Too Long	CSR/O	1	0	0	0	0	1	0	0	1
	Resolution	Unsatisfactory	CSR	1	1	1	0	0	3	0	4	16
		Not Treated Fairly	CSR/O	0	0	0	0	0	0	0	0	2
		Next Steps Not Clear	CSR	0	0	0	0	0	0	0	0	0
	Redirection	Manufacturer	Org	0	0	0	0	0	0	0	0	0
		Competitor	Org	0	0	0	0	0	0	0	0	0
		Store	Org	0	0	1	0	0	1	0	0	0
		Internet	Org	0	0	0	1	0	0	0	1	2
		Other	Org	1	0	1	1	0	2	0	3	4
	Products / Services	Tech Didn't Fix Problem	Org	0	0	0	0	0	0	0	3	2
		Not Satisfied	Org	1	1	1	0	0	3	0	0	1

Note: Other is not included

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Repeat Calls

Tier 2 Repeat Call Reasons

Commercial Tracking

	Tier 1	Tier 2	SOE	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD Total 2015	Monthly Avg 2015	2014	2013
		Sample Size		106	140	143	103	109	389	43	452	538
		Repeat Call Frequency		41	43	57	40	46	141	16	172	184
Fix 3rd	Information	Inconsistent	CSR	1	0	0	0	0	1	0	1	1
		Incomplete	CSR	2	4	1	1	0	7	1	4	8
		Incorrect	CSR	1	0	2	0	2	3	0	5	6
	Policy	Not Authorized User	Cust/O	1	1	2	0	2	4	0	5	2
		Credit	Cust/O	0	0	0	0	0	0	0	1	0
		Disagreement	Cust/O	1	1	0	0	0	2	0	5	1
	Customer	Provide More Info	Cust	4	3	3	1	3	10	1	7	13
		Missed Appointment	Cust	0	0	0	0	0	0	0	0	0
		Error	Cust	1	1	0	0	1	2	0	3	3
		Decision/Changed Mind	Cust	0	0	0	2	0	0	0	2	0
Fix 4th	Billing	Incorrect	Org	0	0	1	0	0	1	0	4	1
		Corrections Not Done	CSR/O	0	0	0	0	1	0	0	2	2
		Payment Related	Cust/O	2	2	1	2	0	5	1	8	8
		Bill Unclear	Org	0	2	0	0	0	2	0	1	4
		Explain Charges	CSR	0	1	2	0	0	3	0	0	8
	Call Center	Closed	Org	0	3	0	1	1	3	0	3	7
		Wait Time - Too Long	Org	2	2	2	7	6	6	1	17	9
		Busy Signal	Org	0	0	1	0	0	1	0	0	1
		Computer System	Org	1	0	1	0	0	2	0	1	4
		Call Back/Again	Org	0	0	0	1	0	0	0	5	5
	Language	Barrier - Customer	Cust	0	0	0	0	0	0	0	0	0
		Barrier - CSR	CSR	0	0	0	0	0	0	0	0	0

Note: Other is not included

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Repeat Calls

Repeat Call Reasons - Tier 1
Total YTD 2015

Repeat Calls Frequency → **Repeat Calls Satisfaction** → **First Call Resolution Targeted Opportunities**

Ranking			
1	Verifying/Request	234	*Higher Frequency*
2	Call Center	195	
3	Billing	160	
4	CSR Approach	155	
5	Customer	139	
6	CSR Knowledge	137	
7	IVR	128	
8	CSR Information	90	
9	Call Length	89	
10	Policy	73	
11	Resolution	65	
12	Redirection	59	*Lower Frequency*
13	Products/Services	16	

Ranking			
1	Customer	68%	*More Satisfied*
2	Redirection	56%	
3	IVR	51%	
4	Call Center	50%	
5	Verifying/Request	49%	
6	Call Length	43%	
7	CSR Information	42%	
8	Billing	39%	
9	Products/Services	38%	
10	Policy	26%	
11	CSR Knowledge	21%	
12	CSR Approach	21%	*Less Satisfied*
13	Resolution	15%	

	Gap	
CSR Approach	-8	Fix 1st
CSR Knowledge	-5	
Billing	-5	
Verifying/Request	-4	Fix 2nd
Call Center	-2	
Resolution	-2	
Policy	0	Fix 3rd
CSR Information	1	
Call Length	3	
Products/Services	4	Fix 4th
IVR	4	
Customer	4	
Redirection	10	

Note: Other is not included

Sample Size: Total YTD 2015 n=1,547

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Repeat Calls

Frequency - Tier 1 Main Reason

Total Tracking

Tier 1	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD 2015	2014	2013	2012	2011	2010	2009	2008	2007
Sample Size	1,506	1,731	1,895	1,724	1,914	5,132	7,907	9,907	9,238	9,680	9,415	9,868	8,650	3,817
Repeat Call Frequency	418	541	588	560	614	1,547	2,485	2,972	3,100	2,491	2,254	2,325	2,060	1,083
Billing	28	54	78	61	69	160	323	426	399	321	340	360	210	104
Call Center	44	64	87	96	135	195	356	260	409	235	198	228	139	90
CSR Approach	35	58	62	35	51	155	238	252	203	146	111	142	179	78
Customer	54	39	46	47	51	139	238	338	274	304	265	336	392	175
Call Length	32	22	35	27	39	89	114	108	135	74	62	48	50	24
CSR Knowledge	36	47	54	50	58	137	225	229	209	111	102	92	128	62
CSR Information	27	28	35	30	36	90	180	291	237	169	213	215	150	75
IVR	37	44	47	44	26	128	144	149	116	131	103	114	143	110
Language	2	1	4	1	0	7	3	14	12	10	4	3	7	3
Policy	22	26	25	35	33	73	126	73	94	60	45	50	28	21
Verifying/Request	56	101	77	85	81	234	330	379	511	487	497	450	372	222
Resolution	22	26	17	15	14	65	79	300	340	295	209	172	215	100
Redirection	20	25	14	29	16	59	88	133	129	100	70	33	15	7
Products/Services	3	6	7	5	5	16	41	20	32	48	35	82	31	12

Note: Other is not included

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Repeat Calls

Satisfaction - Tier 1 Main Reason

Total Tracking

Tier 1	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD 2015	2014	2013	2012	2011	2010	2009	2008	2007
Sample Size	1,506	1,731	1,895	1,724	1,914	5,132	7,907	9,907	9,238	9,680	9,415	9,868	8,650	3,817
Repeat Call Frequency	418	541	588	560	614	1,547	2,485	2,972	3,100	2,491	2,254	2,325	2,060	1,083
Billing	36%	48%	33%	30%	26%	39%	33%	35%	27%	33%	34%	38%	36%	28%
Call Center	57%	45%	49%	52%	48%	50%	50%	47%	43%	50%	55%	49%	44%	40%
CSR Approach	20%	22%	19%	26%	18%	21%	14%	17%	11%	13%	13%	23%	19%	21%
Customer	65%	69%	72%	66%	69%	68%	67%	64%	64%	67%	65%	73%	66%	68%
Call Length	47%	41%	40%	52%	49%	43%	52%	47%	38%	58%	37%	42%	38%	38%
CSR Knowledge	19%	21%	22%	20%	24%	21%	21%	19%	12%	19%	26%	22%	27%	19%
CSR Information	44%	54%	31%	33%	39%	42%	37%	40%	34%	44%	35%	38%	31%	21%
IVR	46%	48%	57%	39%	50%	51%	44%	42%	46%	44%	44%	32%	33%	28%
Language	50%	100%	50%	100%	0%	57%	100%	43%	33%	40%	25%	67%	14%	0%
Policy	14%	42%	20%	14%	21%	26%	20%	27%	20%	18%	47%	27%	36%	24%
Verifying/Request	50%	49%	49%	59%	46%	49%	53%	51%	44%	55%	54%	47%	53%	47%
Resolution	18%	15%	12%	20%	36%	15%	20%	23%	19%	19%	18%	20%	19%	21%
Redirection	55%	64%	43%	45%	25%	56%	36%	50%	36%	43%	49%	31%	20%	43%
Products/Services	33%	50%	29%	60%	0%	38%	34%	35%	13%	33%	31%	27%	35%	18%

Note: Other is not included

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Repeat Calls

Non-FCR - Tier 1 Main Reason

Total Tracking

Tier 1	QTR 3 2015		QTR 2 2015		QTR 1 2015		QTR 4 2014		YTD 2015	
	Repeat Call Frequency	Non - FCR Percentage	Repeat Call Frequency	Non - FCR Percentage	Repeat Call Frequency	Non - FCR Percentage	Repeat Call Frequency	Non - FCR Percentage	Repeat Call Frequency	Non - FCR Percentage
	434	29%	579	33%	618	33%	591	34%	1,631	32%
Billing	28	1.9%	54	3.1%	78	4.2%	61	3.5%	160	3.1%
Call Center	44	2.9%	64	3.6%	87	4.6%	96	5.5%	195	3.8%
CSR Approach	35	2.3%	58	3.3%	62	3.3%	35	2.0%	155	3.0%
Customer	54	3.6%	39	2.2%	46	2.5%	47	2.7%	139	2.7%
Call Length	32	2.1%	22	1.3%	35	1.9%	27	1.6%	89	1.7%
CSR Knowledge	36	2.4%	47	2.7%	54	2.9%	50	2.9%	137	2.7%
CSR Information	27	1.8%	28	1.6%	35	1.9%	30	1.7%	90	1.8%
IVR	37	2.5%	44	2.5%	47	2.5%	44	2.5%	128	2.5%
Language	2	0.1%	1	0.1%	4	0.2%	1	0.1%	7	0.1%
Policy	22	1.5%	26	1.5%	25	1.3%	35	2.0%	73	1.4%
Verifying/Request	56	3.7%	101	5.8%	77	4.1%	85	4.9%	234	4.6%
Resolution	22	1.5%	26	1.5%	17	0.9%	15	0.9%	65	1.3%
Redirection	20	1.3%	25	1.4%	14	0.7%	29	1.7%	59	1.2%
Products/Services	3	0.2%	6	0.3%	7	0.4%	5	0.3%	16	0.3%
Other	16	1.1%	38	2.2%	30	1.6%	31	1.8%	84	1.6%

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Repeat Calls

Tier 2 Repeat Call Reasons

Total Tracking

	Tier 1	Tier 2	SOE	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD Total 2015	Monthly Avg 2015	2014	2013
		Sample Size		1,506	1,731	1,895	1,724	1,914	5,132	570	7,907	9,907
		Repeat Call Frequency		418	541	588	560	614	1,547	172	2,485	2,972
Fix 1st	Approach	CSR Didn't Call Back	CSR	3	8	7	7	6	18	2	37	28
		Not Helpful/Caring	CSR	18	22	28	12	17	68	8	119	135
		CSR Lacked Authority	CSR/O	12	17	16	10	22	45	5	55	40
		No Confidence in CSR	CSR	0	4	1	1	4	5	1	9	22
		Rude	CSR	2	7	10	5	2	19	2	18	27
	Knowledge	Fix Problem	CSR	20	32	48	36	37	100	11	176	212
		Not Aware of Promo	CSR	1	0	0	0	0	1	0	0	0
		Products/Services	CSR	15	15	6	14	21	36	4	49	17
	Billing	Incorrect	Org	2	4	5	2	14	11	1	47	60
		Corrections Not Done	CSR/O	3	1	1	10	9	5	1	38	37
		Payment Related	Cust/O	21	31	54	36	38	106	12	165	215
		Bill Unclear	Org	0	7	2	5	3	9	1	27	35
		Explain Charges	CSR	2	11	16	8	5	29	3	46	79
Fix 2nd	Verify / Request	Verify/Check Status	Org	47	82	58	70	47	187	21	229	271
		Request Not Done	CSR/O	9	19	19	15	34	47	5	101	108
	Call Center	Closed	Org	15	19	20	14	17	54	6	58	92
		Wait Time - Too Long	Org	18	38	51	72	105	107	12	247	103
		Busy Signal	Org	4	0	10	2	5	14	2	15	17
		Computer System	Org	6	5	5	4	6	16	2	18	22
		Call Back/Again	Org	1	2	1	4	2	4	0	18	26
	Resolution	Unsatisfactory	CSR	21	22	14	15	10	57	6	69	285
		Not Treated Fairly	CSR/O	0	1	3	0	0	4	0	1	8
		Next Steps Not Clear	CSR	1	3	0	0	4	4	0	9	7

Note: Other is not included

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Repeat Calls

Tier 2 Repeat Call Reasons

Total Tracking

	Tier 1	Tier 2	SOE	QTR 3 2015	QTR 2 2015	QTR 1 2015	QTR 4 2014	QTR 3 2014	YTD Total 2015	Monthly Avg 2015	2014	2013
		Sample Size		1,506	1,731	1,895	1,724	1,914	5,132	570	7,907	9,907
		Repeat Call Frequency		418	541	588	560	614	1,547	172	2,485	2,972
Fix 3rd	Policy	Not Authorized User	Cust/O	11	8	12	8	13	31	3	40	34
		Credit	Cust/O	0	1	0	0	0	1	0	3	0
		Disagreement	Cust/O	11	17	13	27	20	41	5	83	39
	Information	Inconsistent	CSR	2	2	3	7	3	7	1	29	32
		Incomplete	CSR	17	17	15	14	19	49	5	89	172
		Incorrect	CSR	8	9	17	9	14	34	4	62	87
	Call Length	Hold - Disconnected	CSR/O	8	12	28	17	24	48	5	67	75
		Hold - Too Long	CSR/O	20	9	7	9	13	36	4	42	22
		Call - Too Long	CSR/O	4	1	0	1	2	5	1	5	11
Fix 4th	Products / Services	Tech Didn't Fix Problem	Org	0	1	1	2	1	2	0	15	12
		Not Satisfied	Org	3	5	6	3	4	14	2	26	8
	IVR	Language Issue	Org	0	0	0	0	0	0	0	1	0
		Not Clear/No Proper Options	Org	19	30	32	27	17	81	9	81	92
		Didn't Recognize Voice	Org	2	3	0	2	2	5	1	7	3
		Too Many Options	Org	5	1	3	6	0	9	1	11	15
		Disconnected	Org	3	6	9	4	4	18	2	21	23
		Wrong Dept	Org	8	4	3	5	3	15	2	23	16
	Customer	Provide More Info	Cust	33	20	30	25	36	83	9	141	197
		Missed Appointment	Cust	0	0	0	0	0	0	0	0	0
		Error	Cust	15	11	14	16	11	40	4	65	98
		Decision/Changed Mind	Cust	6	8	2	6	4	16	2	32	43
	Redirection	Manufacturer	Org	0	0	0	0	0	0	0	0	1
		Competitor	Org	0	0	0	0	0	0	0	0	1
		Store	Org	2	2	2	0	2	6	1	3	3
		Internet	Org	5	5	3	3	6	13	1	19	21
		Other	Org	13	18	9	26	8	40	4	66	107
	Language	Barrier - Customer	Cust	0	1	0	0	0	1	0	0	3
		Barrier - CSR	CSR	2	0	4	1	0	6	1	3	11

Note: Other is not included

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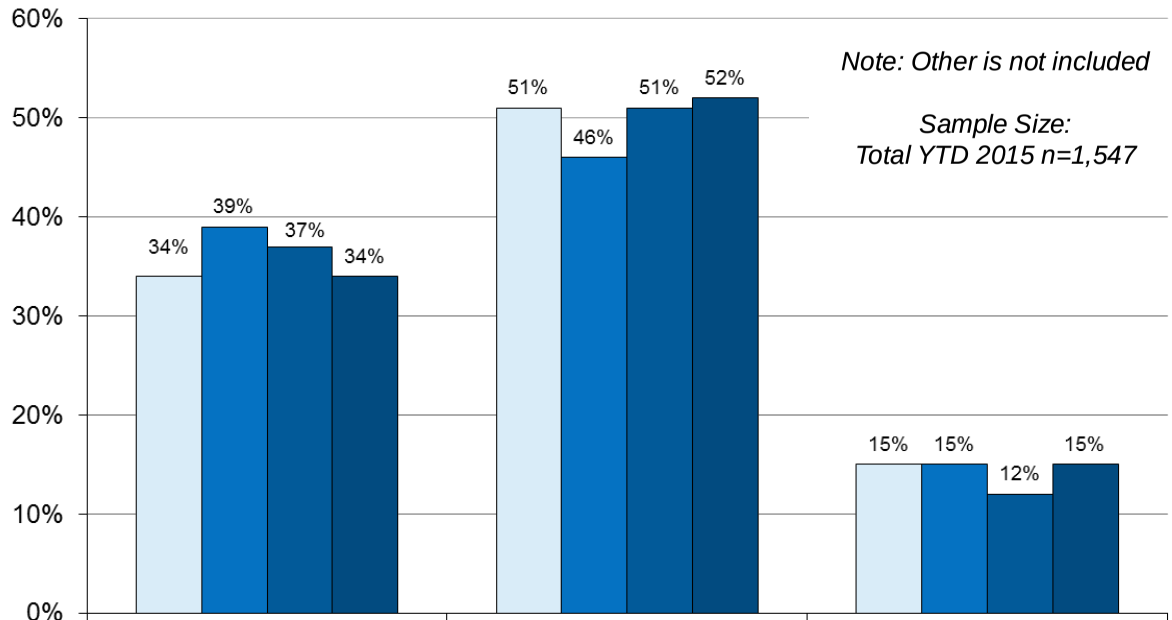
Repeat Calls

Source of Error Benchmarking



	CSR	Organization	Customer
Total YTD 2015	34%	51%	15%
Average Energy	39%	46%	15%
Average Call Center	37%	51%	12%
Average World Class Call Center	34%	52%	15%

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Repeat Calls

Source of Error
Residential Tracking

Time Frame	CSR	Organization	Customer	Sample Size
QTR 3 2015	33%	49%	18%	377
QTR 2 2015	34%	54%	12%	498
QTR 1 2015	34%	51%	15%	531
QTR 4 2014	28%	57%	15%	520
QTR 3 2014	31%	55%	14%	568
QTR 2 2014	37%	45%	18%	532
QTR 1 2014	41%	44%	15%	702
QTR 4 2013	44%	40%	16%	728
YTD 2015	34%	51%	15%	1,406
2014	35%	49%	16%	2,313
2013	43%	41%	17%	2,788
2012	41%	47%	13%	2,566
2011	36%	48%	16%	2,065
2010	35%	48%	17%	1,841
2009	33%	47%	20%	1,775
2008	38%	40%	22%	1,594
2007	34%	46%	20%	832

Note: Other is not included

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Repeat Calls

Source of Error
Commercial Tracking

Time Frame	CSR	Organization	Customer	Sample Size
QTR 3 2015	34%	49%	17%	41
QTR 2 2015	30%	56%	14%	43
QTR 1 2015	49%	44%	7%	57
QTR 4 2014	30%	60%	10%	40
QTR 3 2014	39%	50%	11%	46
QTR 2 2014	30%	52%	18%	44
QTR 1 2014	43%	48%	9%	44
QTR 4 2013	41%	48%	11%	46
YTD 2015	39%	49%	12%	141
2014	36%	52%	12%	172
2013	41%	48%	11%	184
2012	39%	48%	14%	534
2011	36%	48%	15%	426
2010	37%	47%	16%	413
2009	36%	47%	17%	550
2008	40%	39%	21%	466
2007	38%	44%	18%	251

Note: Other is not included

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Repeat Calls

Source of Error
Total Tracking

Time Frame	CSR	Organization	Customer	Sample Size
QTR 3 2015	33%	49%	18%	418
QTR 2 2015	34%	54%	13%	541
QTR 1 2015	35%	51%	14%	588
QTR 4 2014	29%	57%	15%	560
QTR 3 2014	32%	54%	14%	614
QTR 2 2014	36%	45%	18%	576
QTR 1 2014	41%	44%	15%	746
QTR 4 2013	44%	41%	16%	774
YTD 2015	34%	51%	15%	1,547
2014	35%	50%	15%	2,485
2013	43%	41%	16%	2,972
2012	40%	47%	13%	3,100
2011	36%	48%	16%	2,491
2010	35%	48%	17%	2,254
2009	34%	47%	19%	2,325
2008	38%	39%	22%	2,060
2007	35%	46%	19%	1,083

Note: Other is not included

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Repeat Calls

Selection Grid for Repeat Call Reduction
Total YTD 2015

Note: Top 5 are highlighted in blue in each column; only data equal to or greater than 5 will be highlighted

Tier 1	Tier 2	SOE	Repeat Calls	Customer Dissatisfaction	Customer At Risk
	Repeat Call Frequency		1,547	451	271
	Top 5 Percentage		38%	37%	45%
Verify/Request	Needed to Verify/Check Status	Org	187	28	15
Call Center	Wait Time to Reach CSR Too Long	Org	107	21	5
Billing	Payment Related	Cust/O	106	22	14
Knowledge	Lack of Knowledge to Fix Problem	CSR	100	40	31
Customer	Needed to Provide More Info	Cust	83	9	6
Approach	Not Helpful/Caring	CSR	68	47	31
Resolution	Unsatisfactory Solution	CSR	57	26	20
Verify/Request	Request Not Done	CSR/O	47	23	10
Approach	CSR Lacked Authority	CSR/O	45	18	18
Policy	Policy Disagreement	Cust/O	41	22	19

Customer Dissatisfaction: Customers who are somewhat dissatisfied or very dissatisfied with their call center experience

Customer At Risk: Customers who chose any of the bottom 3 response choices for continue to use the organization's products/services and whose call was unresolved

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Customer Reporting Framework

- KPI Dashboard
- Call Handling
- Csat Metrics
- Repeat Calls
- Customer Protection

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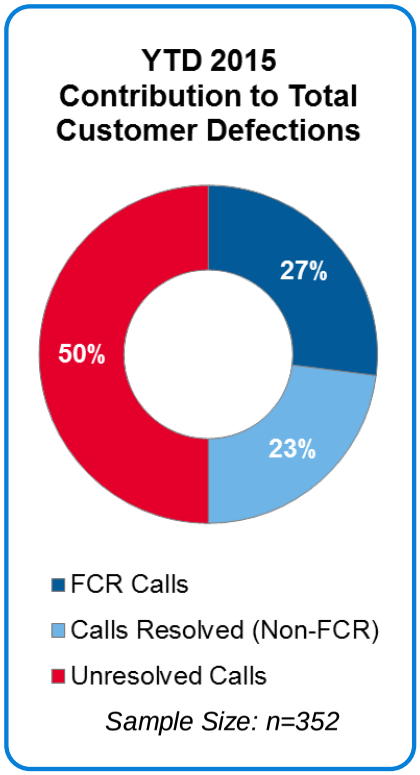
Customer Protection

Call Resolution Metrics Impact on Customer Defections Benchmarking - Residential

Time Frame		FCR	Resolved Repeat Calls	Unresolved Calls	Total % of Customer Defections
QTR 3 2015	% of Customers	72%	17%	11%	6%
	% of Customer Defections	3%	7%	28%	
QTR 2 2015	% of Customers	66%	21%	13%	10%
	% of Customer Defections	3%	12%	39%	
QTR 1 2015	% of Customers	68%	21%	11%	9%
	% of Customer Defections	3%	8%	44%	
QTR 4 2014	% of Customers	66%	21%	13%	8%
	% of Customer Defections	2%	9%	39%	
YTD 2015	% of Customers	69%	20%	12%	8%
	% of Customer Defections	3%	9%	38%	
Average Call Center	% of Customers	70%	17%	13%	5%
	% of Customer Defections	2%	5%	23%	

Customer Defections: % of customers who probably would not or definitely would not continue to use the organization's products or services as a result of their call center experience



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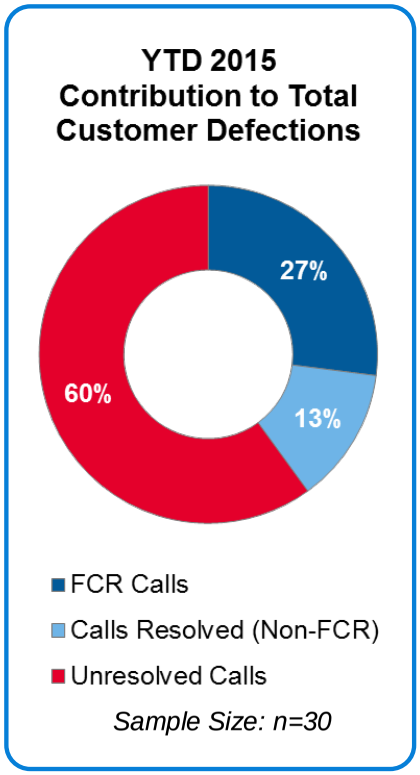
Customer Protection

Call Resolution Metrics Impact on Customer Defections Benchmarking - Commercial

Time Frame		FCR	Resolved Repeat Calls	Unresolved Calls	Total % of Customer Defections
QTR 3 2015	% of Customers	60%	26%	13%	4%
	% of Customer Defections	2%	4%	18%	
QTR 2 2015	% of Customers	65%	22%	13%	6%
	% of Customer Defections	4%	4%	21%	
QTR 1 2015	% of Customers	57%	21%	22%	15%
	% of Customer Defections	5%	8%	45%	
QTR 4 2014	% of Customers	60%	28%	12%	2%
	% of Customer Defections	0%	0%	20%	
YTD 2015	% of Customers	61%	23%	16%	9%
	% of Customer Defections	4%	5%	33%	
Average Call Center	% of Customers	70%	17%	13%	5%
	% of Customer Defections	2%	5%	23%	

Customer Defections: % of customers who probably would not or definitely would not continue to use the organization's products or services as a result of their call center experience



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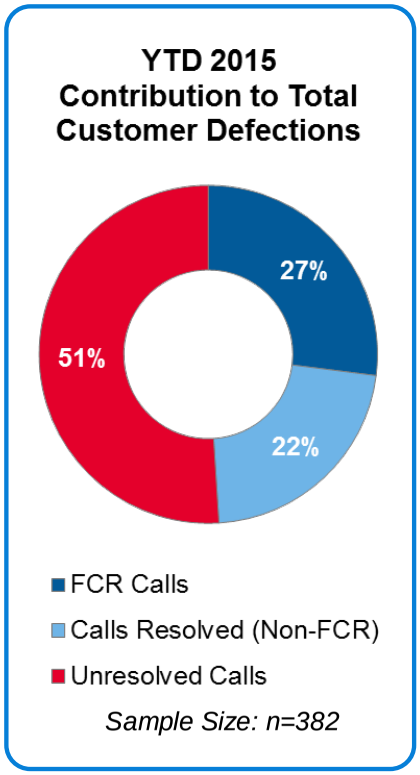
Customer Protection

Call Resolution Metrics Impact on Customer Defections Benchmarking - Total

Time Frame		FCR	Resolved Repeat Calls	Unresolved Calls	Total % of Customer Defections
QTR 3 2015	% of Customers	71%	18%	11%	6%
	% of Customer Defections	3%	7%	27%	
QTR 2 2015	% of Customers	66%	21%	13%	9%
	% of Customer Defections	3%	11%	38%	
QTR 1 2015	% of Customers	67%	21%	12%	9%
	% of Customer Defections	3%	8%	44%	
QTR 4 2014	% of Customers	66%	22%	13%	8%
	% of Customer Defections	2%	8%	38%	
YTD 2015	% of Customers	68%	20%	12%	8%
	% of Customer Defections	3%	9%	38%	
Average Call Center	% of Customers	70%	17%	13%	5%
	% of Customer Defections	2%	5%	23%	

Customer Defections: % of customers who probably would not or definitely would not continue to use the organization's products or services as a result of their call center experience



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Customer Protection

CP SCORE™ Benchmarking

Residential

Time Frame	Customer Protected	Still Favorable	Indifferent	Customer At Risk
QTR 3 2015	72%	10%	14%	4%
QTR 2 2015	67%	12%	15%	6%
QTR 1 2015	67%	13%	14%	6%
QTR 4 2014	64%	13%	15%	7%
QTR 3 2014	64%	14%	15%	6%
YTD 2015	68%	12%	14%	6%
2014	64%	13%	16%	7%
2013	64%	12%	16%	7%
2012	56%	16%	20%	9%
2011	67%	14%	14%	5%
Average Energy	77%	9%	10%	4%
Average Call Center	72%	11%	13%	5%
Average World Class Call Center	85%	6%	7%	2%

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Customer Protection

CP SCORE™ Benchmarking

Commercial

Time Frame	Customer Protected	Still Favorable	Indifferent	Customer At Risk
QTR 3 2015	61%	18%	17%	4%
QTR 2 2015	67%	8%	21%	4%
QTR 1 2015	55%	13%	19%	14%
QTR 4 2014	67%	14%	15%	5%
QTR 3 2014	60%	16%	13%	12%
YTD 2015	61%	12%	19%	8%
2014	61%	14%	16%	9%
2013	58%	15%	20%	7%
2012	55%	17%	19%	9%
2011	63%	16%	14%	6%
Average Energy	77%	9%	10%	4%
Average Call Center	72%	11%	13%	5%
Average World Class Call Center	85%	6%	7%	2%

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Customer Protection

CP SCORE™ Benchmarking

Total

Time Frame	Customer Protected	Still Favorable	Indifferent	Customer At Risk
QTR 3 2015	71%	11%	14%	4%
QTR 2 2015	67%	11%	16%	6%
QTR 1 2015	66%	13%	14%	7%
QTR 4 2014	64%	13%	15%	7%
QTR 3 2014	64%	14%	15%	7%
YTD 2015	68%	12%	15%	6%
2014	64%	14%	16%	7%
2013	64%	13%	16%	7%
2012	56%	16%	20%	9%
2011	67%	14%	14%	5%
Average Energy	77%	9%	10%	4%
Average Call Center	72%	11%	13%	5%
Average World Class Call Center	85%	6%	7%	2%

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Appendix

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Appendix

About Service Quality Measurement Group

SQM Group is a **specialist firm** for assisting organizations in using VoC research data to measure and improve their contact channels' customer experience, operating costs, and retention by providing the following products and services...

- **Contact / Omni-Channel Benchmarking**
- **Contact / Omni-Channel Tracking**
- **FCR Best Practices Consulting**
- **Training**
- **Publications and Presentations**
- **Certification and Awards**

Contact Channels FCR Experts
Using VoC Data to Benchmark, Track, Consult, Recognize and Improve Contact Channels First Contact Resolution Performance

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Appendix

Customer Protection - CP SCORE™
Classification Breakdown

Calls Resolved
Resolved
Unresolved

Call Center Csat
Very Satisfied
Somewhat Satisfied
Somewhat Dissatisfied
Very Dissatisfied

Continue to Use
Definitely Would
Probably Would
Might or Might Not
Probably Would Not
Definitely Would Not

The different rating combinations from the 3 components form the 4 CP SCORE™ levels

1 CUSTOMER PROTECTED
Call: Resolved
Call Center Csat:
Very Satisfied
Continue to Use Products & Services: Definitely Would or Probably Would

2 STILL FAVORABLE
Call: Resolved
Call Center Csat:
Somewhat Satisfied
Continue to Use Products & Services: Definitely Would or Probably Would

3 INDIFFERENT
All other response choice combinations *EXCEPT* those response choice combinations for 1, 2 and 4 classifications

4 CUSTOMER AT RISK
Call: Unresolved
Any response choice for Call Center Csat
Bottom 3 response choices for Continue to Use Products & Services

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Appendix

Key Performance Indicators Definitions

First Call Resolution (FCR): *Customer determines if their call to the call center was resolved on the first call*

Calls Resolved: *Customer determines if their call to the call center was resolved, no matter how many calls it took*

Average Calls to Resolve (ACR): *The average # of calls needed to resolve inquiry are based on total calls made*

Call Center Csat: *Customer determines they were overall very satisfied (top box response) with their call center experience*

CSR Csat: *Customer determines they were overall very satisfied (top box response) with the CSR who handled their call*

CP SCORE™: *Customer determines they definitely or probably would continue to use the organization's products or services, they were overall very satisfied (top box response) with their call center experience and their call was resolved, no matter how many calls it took*

World Class Calls (WCC): *Customer determines they were overall very satisfied (top box response) with their call center experience, were very satisfied with the CSR who handled their call and their call was resolved, no matter how many calls it took*

Action Alert Calls: *Customer determines they were overall somewhat or very dissatisfied with their call center experience and their call was unresolved*

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Appendix

Average Call Center Quartile Ranking Standards

Metrics	Average Call Center	World Class Standards	1st Quartile	2nd Quartile	3rd Quartile	4th Quartile
First Call Resolution	70%	80%	76% +	75% - 71%	70% - 65%	64% -
Calls Resolved	87%	95%	92% +	91% - 88%	87% - 85%	84% -
Avg. # Calls to Resolve	1.45	1.20	1.33 -	1.34 - 1.40	1.41 - 1.53	1.54 +
Call Center Csat	75%	85%	80% +	79% - 77%	76% - 71%	70% -
CSR Csat	82%	90%	86% +	85% - 83%	82% - 79%	78% -
CP SCORE™	72%	85%	78% +	77% - 73%	72% - 68%	67% -
World Class Calls	71%	80%	77% +	76% - 72%	71% - 67%	66% -
Action Alert Calls	6%	1%	0% - 3%	4% - 5%	6% - 7%	8% +

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BC Hydro Customer Tracking Survey

Including Corp CSAT and Cross Channel Questions

Good (morning, afternoon or evening), may I please talk to (name)?
Yes, speaking or different person……..Continue
No……..Schedule Callback

Hello, this is (Name) calling from SQM Group, an independent customer satisfaction survey firm. We have been asked by BC Hydro to conduct a brief survey about their call center customer service. This call is being recorded and may be monitored for quality purposes.

Are we calling you on your cell phone while you are driving?

- Yes – *TSR to say:* I'm sorry but for safety reasons we cannot continue with the survey, but we thank you for taking the call and wish you a good day. *(end survey)*
- No *(continue with survey)*

May I ask you some questions about how they're doing? It takes about 4-5 minutes.
Yes……..……..……..……..……...Continue
No…….Schedule callback and thank
Refused……..Thank and terminate call
Thank you, we really appreciate the opportunity to get your feedback.

The information gathered through this survey is collected under the authority of the Hydro and Power Authority Act and BC Hydro's Electric Tariff, as regulated by the British Columbia's Utilities Commission. The information we collect from you will be treated confidentially and handled in accordance with the provisions of the Freedom of Information and Privacy Act. If you have questions about why BC Hydro is conducting this study, you are invited to call their Customer Advocacy Team at 1-866-355-6766.

A. Since your call on (call date) have you called back into BC Hydro's call center? Would you say…

- Yes
- No

Satisfaction / First Call Resolution

1. Based on your last call to their call center, overall how satisfied are you with BC Hydro's call center? Would you say you are…

- Very Satisfied
- Somewhat Satisfied
- Somewhat Dissatisfied
- Very Dissatisfied

TSR to record customer comments
Why are you **(less than VS ratings)** with BC Hydro's call center?
Stop recording

1a. Again, based on your last call to their call center and if you had the choice, would you continue to use BC Hydro's products or service? Would you say…

- Definitely Would
- Probably Would
- Might or Might Not
- Probably Would Not
- Definitely Would Not
- Don't Know (*Do not read)*

2. Did the call center resolve your inquiry? Would you say…

- Yes or No *(If Yes, go to question 3) (If No, go to question 4)*

3. In total, how many calls did you have to make to their call center to resolve your initial inquiry? Would you say…

- 1 call *(Go to question B)*
- 2 calls *(2 calls or more go to question 5)*
- 3 calls
- 4 or more calls
- Not sure *(Do not read)*

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4. In total, how many calls have you made trying to resolve your initial inquiry? Would you say…

- 1 call
- 2 calls
- 3 calls
- 4 or more calls
- Not sure *(Do not read)*

TSR to record customer comments

5. Can you tell me why your inquiry was not resolved in one call?

Stop recording

2+ calls table

Main Area for 2+ Calls	Sub Area for 2+ Calls	Source of Error
a. Billing	a1.Incorrect	Organization
	a2. Corrections Not Done	CSR/Org
	a3. Payment Related	Cust/Org
	a4. Bill Unclear	Organization
	a5. Explain Charges	CSR
b. Call Center	b1. Call Center/Closed	Organization
	b2. Wait Time to Reach CSR Too Long	Organization
	b3. Busy Signal	Organization
	b4. Computer System Not Working	Organization
	b5. Call Back/Again	Organization
c. CSR Approach	c1. CSR Did Not Call Back	CSR
	c2. Not Helpful/Caring	CSR
	c3. CSR Lacked Authority	CSR/Org
	c4. No Confidence in CSR	CSR
	c5. Rude	CSR
d. Customer	d1. Needed to Provide More Information	Customer
	d2. Customer Missed Tech Service Appointment	Customer
	d3.Error	Customer
	d4. Decision/Changed Mind	Customer
e. Call Length	e1. Hold - Customer was Disconnected	CSR/Org
	e2. Hold - too long	CSR/Org
	e3. Call - too long	CSR/Org
f. CSR Knowledge	f1. Lack of Knowledge to Fix Problem	CSR
	f2. Not Aware of Promo	CSR
	f3. Lack of Knowledge Products/Services	CSR
g. CSR Information	g1. Inconsistent Info	CSR
	g2. Incomplete Info	CSR
	g3. Incorrect Info	CSR
h. IVR	h1. Language Issue	Organization
	h2. Not Clear/No Proper Options	Organization
	h3. IVR Did Not Recognize Customer Voice	Organization
	h4. Too Many Options	Organization
	h5. Disconnected	Organization
	h6. Wrong Dept	Organization
i. Language	i1. Barrier - Customer	Customer
	i2. Barrier - CSR	CSR
j. Policy	j1. Not Authorized User	Cust/Org
	j2. Credit	Cust/Org
	j3. Policy Disagreement	Cust/Org
k. Verifying/Request	k1. Needed to Verify/Check Status	Organization
	k2. Request Not Done	CSR/Org
l. Resolution	l1.Unsatisfactory Solution	CSR
	l2. Customer Was Not Treated Fairly	CSR/Org
	l3. Next Steps Not Clear	CSR
m. Redirection	m1. Redirection to/from Manufacture	Organization
	m2. Redirection to/from Competitor	Organization
	m3.Redirection to/from Store	Organization
	m4. Redirection to/from Internet	Organization
	m5. Redirection to/from Other	Organization
n. Products/Services	n1. Tech Did Not Fix Problem	Organization
	n2. Not Satisfied with Product/Service	Organization
o. Other	o1. Any Issue Not Covered	Other
	o2. No Feedback	Other

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B. During your call did the customer representative transfer your call to another person? Would you say…

- Yes *(Go to question B1)*
- No *(Go to Script 2)*

B1. Was your call transferred to a Supervisor or to another department? Would you say…

- A Supervisor *(Go to Script 1)*
- Another department (*Go to question B2*)
- Not sure (*Do not read; go to Script 2)*

TSR to record customer comments
B2. Please describe/name the department you were transferred to. *(Go to Script 2)*
Stop recording

Script 1
For the remaining questions it is very important that your rating choices are based on the **First** customer representative that you spoke to.

Script 2 *(Read to **all** customers)*
Now I am going to ask you a series of questions. For most questions I will ask you how satisfied you are using a rating scale of 1 to 5 where 1 = very satisfied, 2 = satisfied, 3 = neutral, 4 = dissatisfied and 5 = very dissatisfied. Of course, you may use any number between 1 and 5 that best describes your level of satisfaction for each question.

Opening

	1 = Very Satisfied	2 = Satisfied	3 = Neutral	4 = Dissatisfied	5 = Very Dissatisfied	Don't know/ Not applicable
7. How satisfied were you with the ease of using the voice menu system to connect you to the right customer representative? *(Again, using a rating scale range # where 1 = Very Satisfied & 5 = Very Dissatisfied, would you say you are 1,2,3,4 or 5) (TSR does **not** read list, select customer's response)*	❑	❑	❑	❑	❑	❑

TSR to record customer comments
Why are you **(dissatisfaction ratings only)**?
Stop recording

Treating

8. How satisfied were you with the customer representative's ability to demonstrate that they genuinely cared about handling your call? *(TSR does **not** read list, select customer's response)*	❑	❑	❑	❑	❑	❑

TSR to record customer comments
Why are you **(dissatisfaction ratings only)**?
Stop recording

9. How satisfied were you with the willingness of the customer representative to help you? *(TSR does **not** read list, select customer's response)*	❑	❑	❑	❑	❑	❑

TSR to record customer comments
Why are you **(dissatisfaction ratings only)**?
Stop recording

Resolving

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10. How satisfied were you with the customer representative's knowledge level? *(TSR does **not** read list, select customer's response)* ❑ ❑ ❑ ❑ ❑ ❑

TSR to record customer comments
Why are you **(dissatisfaction ratings only)**?
Stop recording

11. How satisfied were you that the customer representative could make a decision on your inquiry or problem? *(TSR does **not** read list, select customer's response)* ❑ ❑ ❑ ❑ ❑ ❑

TSR to record customer comments
Why are you **(dissatisfaction ratings only)**?
Stop recording

12. How satisfied were you with the customer representative's ability to resolve your call? *(TSR does **not** read list, select customer's response)* ❑ ❑ ❑ ❑ ❑ ❑

TSR to record customer comments
Why are you **(dissatisfaction ratings only)**?
Stop recording

13. (*Ask only customers who have/had to call 2 or more times*) ❑ ❑ ❑ ❑ ❑ ❑
How satisfied were you with the customer representative's ability to explain clearly the next steps that were required to solve your inquiry or problem? *(TSR does **not** read list, select customer's response)*

TSR to record customer comments
Why are you **(dissatisfaction ratings only)**?
Stop recording

14. Overall how satisfied were you with the customer representative who handled your call? Would you say you are…

- Very Satisfied
- Somewhat Satisfied
- Somewhat Dissatisfied
- Very Dissatisfied

TSR to record customer comments
Why are you **(All ratings)** with the customer representative who handled your call?
Stop recording

CSR Csat Tagging Tier 1	CSR Csat Tagging Tier 2
1. Understand Me	1a. Understand Reason for Call
	1b. Clarity
	1c. Listening
	1d. Language
2. Help Me	2a. Helpful
	2b. Knowledge
	2c. Call Length
	2d. Confidence
	2e. Transfer
	2f. Sales
3. Care About Me	3a. Greeting
	3b. Build Rapport
	3c. Empathy

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	3d. Appreciation
	3e. Live Hold
	3f. Trust
4. Resolve Me	4a. Resolution
	4b. Authority
	4c. Ownership
	4d. Fair Treatment
	4e. Summarizes Call
	4f. Follow Through
	4g. Next Steps
	4h. Confirming Resolution
	4i. Customer Satisfaction

15 Based on your last call to the call center, how memorable was your customer experience? Would you say it was… *(TSR to read all options)*

- A very positive memorable experience
- Positive
- Not memorable
- Negative
- A very negative memorable experience
- Don't Know *(Do not read)*

16. Thinking about BC Hydro, would you say you are Very Satisfied, Satisfied, Dissatisfied, or Very Dissatisfied when it comes to each of the following areas:

	Very Satisfied	Satisfied	Dissatisfied	Very Dissatisfied
a. Value for money	❑	❑	❑	❑
b. Providing reliable electricity	❑	❑	❑	❑
c. Their commitment to customer service	❑	❑	❑	❑
d. Acting in the best interests of British Columbians	❑	❑	❑	❑
e. Their efforts to communicate with customers and communities	❑	❑	❑	❑

17. Overall, would you say that BC Hydro is meeting, exceeding, or falling short of your expectations? Would you say…

- Falling short of expectations
- Meeting expectations
- Exceeding expectations
- Don't Know *(Do not read)*

Cross Channel

18. Prior or after your last call center experience, did you use another method of contact such as their website or Automated Voice Menu for the same inquiry? Would you say…

- Yes or No *(If 'Yes', go to question 19) (If 'No', end survey*)

19. What was your other method of contact? Would you say… *Note: Don't Know = The other contact method*

- Their website
- Their Automated Voice Menu (Self-service)
- The other contact method (*Do not read*)

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20. Did you use **(contact method)** prior to or after calling the call center? Would you say…
- Prior (*Go to question 22*)
- After

Ask customers who said 'No' to question 2 AND selected 'After' for question 20
21a. Were you able to resolve your inquiry using (contact method name)? Would you say…
- Yes (*End survey*)
- No (*Go to question 22*)

Ask cx who said 'Yes' to question 2 AND selected 'After' for question 20
TSR to record customer comments
21b. Earlier you said your inquiry was resolved by the call center, can you please explain why you used **(contact method)** after calling the call center? *(End survey)*
Stop recording

TSR to record customer comments
22. Why was **(contact method)** not able to resolve your inquiry? (*End survey*)
Stop recording

Your feedback is very much appreciated. Again, thank you.

Special Instructions – for non attributable surveys, BU and Rep as per call list; disposition as NCS
Atttrib/Non attrib noted in Category

Business Rules for Attributable/Non Attributable Surveys

Call Backs
1. If customer says 'no', then survey is **Attributable**
2. If customer says '*yes*' AND if call is resolved in 1 call, then survey is **Attributable**
3. If customer says 'yes' AND if call is resolved in 2 or more calls, then survey is **Non Attributable**
4. If customer says 'yes' BUT call is unresolved, then survey is **Non Attributable**

Transfers
1. If customer says 'yes' to question B AND client can identify first / last customer representative OR customer was transferred to a Supervisor, then survey is **Attributable**
2. If customer says 'no' to question B, then survey is **Attributable**
3. If customer says 'yes' to question B but the client cannot identify first / last customer representative, then the survey is **Non Attributable**

World Class Definition
Call Center overall satisfaction = VS
AND
CSR Csat = VS
AND
Call is resolved

Action Alert Definition
Call Center overall satisfaction = SD or VD
AND
Call is not resolved

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215.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.215.1 Please provide each study benchmarking BC Hydro's customer satisfaction, revenue collection, revenue protection, or other customer service activities against national, regional or size-based peer electric companies.

RESPONSE:

Please refer to Attachment 3 to BC Hydro's response to BCOAPO IR 1.198.2 for a comparison of bad debt performance in F2013 to other utilities.

BC Hydro doesn't have recent benchmarking studies regarding the other requested items.

216.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.216.1 Please provide a list of all internal policy constraints placed on the disconnection of service for nonpayment. Such constraints might include, but not be limited to, a minimum dollar level of arrears that must be reached before a disconnection for nonpayment is performed; a minimum age of arrears that must be reached before a disconnection for nonpayment is performed; and other similar policies. For each item on the list, provide the specific constraint. For example, provide the dollar amount above which arrears must be for the account to be disconnected. Provide the age an arrears must be before it is disconnected.

RESPONSE:

Policy constraints are described in BC Hydro's response to BCOAPO IR 1.187.1.

The required age of arrears before disconnection depends on the customer's payment history, as described in BC Hydro's response to BCOAPO IR 1.178.1.

217.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.217.1 Please provide by month for each month January 2012 to present:

(a) The interest rate paid on credit balances for residential accounts using Equalized Billing; and
(b) The interest rate charged on account balances for residential accounts using Equalized Billing.

RESPONSE:

BC Hydro does not pay or charge interest on the differentials of Equal Payment Plan's annual true-up bills.

218.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.218.1 For each month, or other time period as is reasonably available, please provide the number of cash security deposits requested for new customers disaggregated by whether the basis for the security deposit request was: (1) a poor payment history with a public utility; (2) a credit score from Equifax; and (3) a credit score from a credit reporting agency other than Equifax.

RESPONSE:

Please refer to the table below for the number of new customers assessed with a security deposit each calendar year from 2011 to 2015.

Year	Number of Customers
2011	**22,037**
2012	**35,963**
2013	**48,111**
2014	**48,597**
2015	**46,498**

(1) BC Hydro only has a customers' payment history from other utilities when the customer provides a reference of good payment history from another utility. BC Hydro does not have records of poor payment history from another utility.

(2) BC Hydro does not have detailed breakdown information of the reasons for customers who were assessed a security deposit because they did not have a satisfactory payment history with BC Hydro, or did not have sufficient credit history and cannot provide other references, or did not have a 'pass' recommendation from Equifax.

(3) BC Hydro does not use other credit reporting agencies.

219.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.219.1 Please indicate by month, or other time period as is reasonably available, the percentage of Equifax credit scores upon which BC Hydro relied to determine the need to request a cash security deposit which scores were based exclusively on utility bill payment history.

RESPONSE:

The underlying credit details are not known by BC Hydro. In performing a credit check, BC Hydro's call centre agents are provided with a "pass" or "fail" recommendation from Equifax, or a response that credit information is not available. These are determined on the basis of the customer's Equifax credit score. For privacy reasons, agents are not provided with the customer's credit score and BC Hydro does not record the score or underlying credit file details. If the Equifax recommendation is "fail" BC Hydro requires a security deposit; if the recommendation is "passed" a security deposit is not required.

220.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.220.1 For each fiscal year 2012 to current inclusive, separated by residential and non-residential accounts, please provide:

(a) The total budgeted collection costs associated with handling delinquent accounts, excluding administrative and overhead expenses; and
(b) The total actual collection costs associated with handling delinquent accounts, excluding administrative and overhead expenses.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.183.1.

221.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.221.1 Please provide a comprehensive list of the options that a residential customer has to pay their BC Hydro bill. The list of payment options should include, if available, payment through a third party authorized community pay station (or payment center). In addition, for each option:

(a) For each month January 2012 to present, please provide the number of payments received through each option;
(b) Indicate the fee, if any, which is imposed to utilize that option;
(c) Provide a detailed cost justification for that fee; and
(d) For each year 2012 to present, please provide the dollars generated by such fee.

RESPONSE:

BC Hydro offers several options for customers to pay their bills:

- **Online banking;**
- **Pre-authorized payments;**
- **Cheque (by mail or in dropbox at the Dunsmuir or Edmonds offices);**
- **Credit card;**
- **Over-the-counter bank transaction;**
- **At a Service BC location (outside the Lower Mainland);**
- **At a community payment agent (e.g., general store or First Nations band office) in certain remote areas; and**
- **Electronic Funds Transfer (for commercial customers).**

Please refer to Attachment 1 to this response for a summary of payments by month for each option, for the period April 2012 to October 2015.

BC Hydro does not charge a fee for any payment option. However, there is a fee applied to credit card payments by the third-party that provides this service. (The fee from Paymentus, the current provider, is 1.75 per cent).

As discussed in Workshop 3, the rationale for a fee on credit cards is that offering credit cards as a free payment option would encourage a large number of customers currently using low-cost payment channels to a higher cost channel because of the ability to collect points or get cash back. That would increase costs to all ratepayers.

In October 2015, there were 5,989 credit card transactions totaling $1.05 million. The 1.75 per cent additional charge from Paymentus would have been equal to fees of approximately $0.018 million.

Analysis to 2012 is not available because Paymentus' fee structure was changed recently and BC Hydro did not have full visibility into the charges being levied on customers using that service.

222.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.222.1 For each month January 2014 to present, inclusive, provide the total billing by month and the rate at which the billings in each month are converted into receipts, in substantially the following form:

Month	$s of Billed Revenue	Collected Receipts in Dollars													
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	After Dec	Total
JAN															
FEB		---													
MAR		---	---												
APR		---	---	---											
MAY		---	---	---	---										
JUN		---	---	---	---	---									
JUL		---	---	---	---	---	---								
AUG		---	---	---	---	---	---	---							
SEP		---	---	---	---	---	---	---	---						
OCT		---	---	---	---	---	---	---	---	---					
NOV		---	---	---	---	---	---	---	---	---	---				
DEC		---	---	---	---	---	---	---	---	---	---	---			
Etc.															

RESPONSE:

BC Hydro's standard arrears reports provide consolidated account information and so do not have sufficient details to allow a response to this IR.

This notwithstanding, BC Hydro acknowledges the usefulness of this information and so is attempting to extract and analyze account-level transactional data from the SAP billing system. Given the complexity of this analysis (it requires analysis of over 134 million points of data) it will be provided as part of BC Hydro's responses to Round 2 IRs.

223.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.223.1 Please provide a copy of all written documents, of any nature, including tariffs, staff training manuals, and staff “procedures" manuals, that set forth the credit scoring techniques BC Hydro uses for residential customers. Specifically, this request is for all written documents that describe:

(a) The credit scoring techniques, including the factors considered and the weight (or score) given to each factor;
(b) The uses to which BC Hydro puts credit scoring for residential customers; and
(c) The specific decisions (e.g., whether to impose a deposit, whether to allow a deferred payment arrangement, etc.) to which BC Hydro puts the credit scoring analysis.

RESPONSE:

Please refer to BC Hydro’s response to BCOAPO IR 1.178.1.

224.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.224.1 Please provide a list of the names and addresses of locations where a residential customer can walk in and make personal contact with a BC Hydro service representative that:

(a) Is capable of immediately responding to an inquiry about a residential bill;
(b) Can negotiate a deferred payment arrangement for an outstanding bill;
(c) Can negotiate a resolution to an outstanding shutoff for nonpayment; or
(d) Can negotiate a service reconnection after a shutoff for nonpayment.

RESPONSE:

In-person customer service is available for the stated purposes at the following locations:

- **333 Dunsmuir Street, Vancouver (Dunsmuir), and**
- **6911 Southpoint Drive, Burnaby (Edmonds).**

225.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.225.1 For each office listed in response to the data request above, please provide the following:

(a) The actual number of BC Hydro personnel whose job it is to handle these walk-in customer contacts for each year for the past three years;
(b) The budgeted number of BC Hydro personnel whose job it would be to handle these walk-in customer contacts for each year for the past three years; and
(c) The number of walk-in customer contacts for each year for the past three years.

RESPONSE:

In-person service was closed throughout BC Hydro's service area in the mid-1990s.

In-person service was re-launched at the Dunsmuir office in October 2015 and at the Edmonds office in November 2015. Accordingly, there is limited data to report.

In October 2015, there were 87 walk-in customer contacts at the Dunsmuir office. There were an additional 101 walk-in customer contacts in November.

There is not a dedicated budget to staff these locations. The offices are being re-opened on a pilot basis to determine the demand for in-person services. Accordingly, the offices are being staffed using customer service agents normally assigned to the call centre.

226.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

1.226.1 Please provide a list of each:

(a) Community served by BC Hydro, along with the number of residential customers served in that community.
(b) Postal code served by BC Hydro, along with the number of residential customers served in that postal code.

RESPONSE:

Please refer to Attachment 1 to this IR response.

For privacy reasons, BC Hydro can only provide account distribution based on the first three digits of postal codes – Forward Sortation Area (FSA) codes. FSAs with less than 10 accounts are grouped into "Other".

227.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

BCOAPO understands that BC Hydro currently has the ability to place a Late Payment Charges (LPC) lock and Notice bypass on an account, which will waive any late payment charges and Dunning procedures.

1.227.1 Please confirm the existence of the LPC lock and Notice bypass.

RESPONSE:

Confirmed.

BC Hydro refers to the Late Payment Charge lock as the "Interest Lock" and the Notice bypass as the "Dunning Lock."

227.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

BCOAPO understands that BC Hydro currently has the ability to place a Late Payment Charges (LPC) lock and Notice bypass on an account, which will waive any late payment charges and Dunning procedures.

1.227.2 Please confirm whether this is the same thing as a “Dunning lock”.

RESPONSE:

As noted in BC Hydro’s response to BCOAPO IR 1.227.1, a “Dunning lock” is specifically the Notice bypass.

In common terminology, when BC Hydro states it “has placed locks on an account” it means that both the Interest lock and Dunning lock have been applied.

227.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

BCOAPO understands that BC Hydro currently has the ability to place a Late Payment Charges (LPC) lock and Notice bypass on an account, which will waive any late payment charges and Dunning procedures.

1.227.3 What criteria does BCH use when deciding whether to put an LPC lock and bypass notice on an account?

RESPONSE:

Interest and Dunning locks are applied:

- **When, in the judgment of the customer service representative, the customer has a legitimate concern with their account that needs further investigation;**
- **When a customer enters into a formal complaint process (e.g., filed with the Commission); and**
- **For operational issues that would prevent a group of customers from paying their invoice within 21 days of the billing date. For example:**
    - **A delay in bill production or delivery; or**
    - **External events such as a flood or forest fire.**

227.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

BCOAPO understands that BC Hydro currently has the ability to place a Late Payment Charges (LPC) lock and Notice bypass on an account, which will waive any late payment charges and Dunning procedures.

1.227.4 How many accounts had such locks placed on them in 2014?

RESPONSE:

In 2014:

- **79,146 Dunning Locks were placed on 37,938 active accounts.**
- **24,970 Interest Locks were placed on 20,217 active accounts.**

228.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6
Low-income terms and conditions

BCOAPO understands that BC Hydro offers a "third party notification" option, in which a customer can opt to have a third party notified if the customer is facing disconnection (i.e. customer has entered the Dunning process).

1.228.1 Has BC Hydro considered any ways to make this process simpler for customers to set up?

RESPONSE:

The notification option being referenced is the ability for a MyHydro user to link another customer's account to their profile. In this situation, the user has view access to the other customer's accounts and also receives any email notifications that are sent (including Dunning notices).

BC Hydro reviews the usability of its online tools using a variety of methods such as customer polls and focus groups. This feedback is used to improve functionality and ease of use.

Given *FOIPPA* requirements and security concerns, customer consent is required to allow another party to access an account. By its nature, this adds complexity to the process.

229.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6, Table 8-6, p. 8-27
Load limiting

BC Hydro states the following in Table 8-6, which compares the OEB Low Income Customer Rules with BC Hydro's current Electric Tariff Terms and Conditions:

"BC Hydro is investigating the feasibility of using smart meters to limit the allowable load to a customer. If practical, this would allow a customer facing disconnection to be provided with a minimal supply of electricity (i.e., to allow some heating) but also limit the exposure to further non-collection. If this approach is practical, BC Hydro would prefer a load limiting solution to a broad moratorium on winter disconnection"

1.229.1 Please describe what BC Hydro is doing to investigate the option of limiting the allowable load to a customer.

RESPONSE:

Please refer to section 5.4.4 of Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

229.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6, Table 8-6, p. 8-27
Load limiting

BC Hydro states the following in Table 8-6, which compares the OEB Low Income Customer Rules with BC Hydro's current Electric Tariff Terms and Conditions:

"BC Hydro is investigating the feasibility of using smart meters to limit the allowable load to a customer. If practical, this would allow a customer facing disconnection to be provided with a minimal supply of electricity (i.e., to allow some heating) but also limit the exposure to further non-collection. If this approach is practical, BC Hydro would prefer a load limiting solution to a broad moratorium on winter disconnection"

1.229.2 What are the results of BC Hydro's investigation into load limiting so far?

RESPONSE:

Please refer to section 5.4.4 of Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

230.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6.2.3
Ministry of Social Development and Social Innovation (MSDSI)

1.230.1 Is BC Hydro developing information sharing agreements with MSDSI?

RESPONSE:

Yes. Please refer to section 4.2 of Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

230.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6.2.3
Ministry of Social Development and Social Innovation (MSDSI)

1.230.2 If yes, what is the status of those agreements, and what will they cover?

RESPONSE:

Please refer to section 4.2 of Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

231.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6.2, p. 8-32
MSDSI

BC Hydro states the following in the Application with regard to Extended Payment Deferrals and Instalment Plans for Customers Receiving MSDSI Direct Employment Assistance (EA):

"For a customer with an overdue amount incurred while receiving assistance from MSDSI, BC Hydro will make payment arrangements with MSDSI. MSDSI pays 50 per cent of the overdue amount, including the reconnection charge if applicable, when the direct EA is set up and pays the remaining 50 per cent over 12 monthly instalments in addition to the customer's Equal Payment Plan bills"

1.231.1 Please confirm that for the above-referenced customers, MSDSI makes payments directly to BC Hydro, but this amount is deducted from the customer's Employment Assistance? Please also confirm that the customer is not permitted to determine the amount (i.e. it is arranged by BC Hydro and MSDSI).

RESPONSE:

It is BC Hydro's understanding that MSDSI deducts the amount from the customer's Employment Assistance.

It is confirmed that the amount of the payment is determined by BC Hydro and MSDSI.

231.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6.2, p. 8-32
MSDSI

BC Hydro states the following in the Application with regard to Extended Payment Deferrals and Instalment Plans for Customers Receiving MSDSI Direct Employment Assistance (EA):

"For a customer with an overdue amount incurred while receiving assistance from MSDSI, BC Hydro will make payment arrangements with MSDSI. MSDSI pays 50 per cent of the overdue amount, including the reconnection charge if applicable, when the direct EA is set up and pays the remaining 50 per cent over 12 monthly instalments in addition to the customer's Equal Payment Plan bills"

1.231.2 How did BC Hydro and MSDSI arrive at the 50% upfront, 50% in 12 monthly installments arrangement for repayment?

RESPONSE:

BC Hydro understand that 50 per cent upfront/50 per cent in 12 monthly installments arrangement has been in place for over 15 years. BC Hydro is unsure of how this arrangement was determined.

232.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6.2.3, p. 8-33
MSDSI

BC Hydro's Application states that "MSDSI indicated it has approximately 130,000 clients receiving income assistance, the majority being BC Hydro customers."

1.232.1 For F2013 to present, please provide the number, by year, of MSDSI clients that are also BC Hydro customers.

RESPONSE:

BC Hydro does not have access to MSDSI's client lists and so cannot provide this data. The estimate of 130,000 customers is based on MSDSI's estimate of its current clients that may be within BC Hydro's service area.

233.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Section 8.6.2.3, p. 8-33
MSDSI

The Application states that "MSDSI directly pays BC Hydro for the electricity bills of 5,521 of those customers [receiving MSDSI assistance]."

1.233.1 Are the 5,521 customers whose bills are paid directly by MSDSI the result of payment arrangements to avoid disconnection or Equal Payment Plans?

RESPONSE:

This was BC Hydro's estimate of customers for whom MSDSI directly paid their electricity bills on a recurring basis. Low income customers who received a FNOD or have been disconnected can seek MSDSI's assistance to prevent the disconnection or to negotiate payment terms with BC Hydro. However, many customers remain on Direct payments for extended periods; while the customer may have originally been attempting to avoid disconnection, their accounts may currently be in good standing.

Customers whose bills are paid directly by MSDSI must set up Equal Payment Plans.

234.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Chapter 8

1.234.1 Has BC Hydro considered any ways to make it easier for customers to opt for electronic billing?

RESPONSE:

There are three steps required to sign up for electronic billing:

1. **Create a MyHydro profile, which can be done online or by a call centre agent;**
2. **Link an account to the profile, again which can be done online or by a call centre agent; and**
3. **Indicate 'paperless billing' in the account profile, either online or by a call centre agent.**

As indicated in BC Hydro's response to BCOAPO IR 1.228.1, usability of online tools and processes are frequently reviewed, as the adoption of online self-service and paperless billing provide substantially cost savings while also giving customers the ability to better monitor and adjust their energy consumption.

234.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Chapter 8

1.234.2 For example, could BC Hydro regularly offer customers incentives such as draws and contests in order to encourage customers to switch to electronic billing?

RESPONSE:

BC Hydro routinely has marketing campaigns and promotional programs to increase awareness of and increase participation in electronic billing options. BC Hydro primarily uses low-cost and in-house communication channels (e.g., bills, bchydro.com, Twitter, Facebook) but on occasion undertakes broader campaigns using paid media.

BC Hydro also takes advantage of certain types of customer calls (e.g., account set-ups or moves) to increase awareness of online tools and encourage participation in electronic billing. This direct approach has been found to be the most effective method in increasing MyHydro subscriptions and converting customers to electronic billing.

235.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Chapter 8

1.235.1 Apart for street lights, does BC Hydro allow other types of attachments (e.g. by telephone and cable companies) to its poles?

RESPONSE:

Yes, BC Hydro allows other types of attachments to its poles.

235.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Chapter 8

1.235.2 If yes, does it charge for the use of its poles?

RESPONSE:

Yes, BC Hydro charges for the use of other types of attachments to poles.

Many distribution poles are jointly owned with Telus. Depending upon the type and location, the attachment may fall under Telus' jurisdiction (and thus BC Hydro would not charge for use of space, but only for the service connection and electrical use, if any).

235.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Chapter 8

1.235.2 If yes, does it charge for the use of its poles?

1.235.2.1 If yes, what is the charge and why is in not included as a Standard Charge?

RESPONSE:

Charges for attachments to a pole include recovery of costs to facilitate installation as well as for the use of space. Charges are set by a variety of commercial agreements and vary depending upon the type of attachment.

Many attachments do not include components of electrical use, such as fibre optic cable, and thus are not appropriate to be included as a Standard Charge in BC Hydro's Electric Tariff.

Where an attachment requires electricity, an additional charge for the service connection and electric use as per the Electric Tariff is charged.

235.0 CHAPTER 8 ELECTRIC TARIFF TERMS AND CONDITIONS

Reference: Exhibit B-1, Chapter 8

1.235.2 If yes, does it charge for the use of its poles?

1.235.2.2 If not, why not?

RESPONSE:

Please refer to BC Hydro's response to the BCOAPO IR 235.2.1.

William J. Andrews

Barrister & Solicitor

1958 Parkside Lane, North Vancouver, BC, Canada, V7G 1X5
Phone: 604-924-0921, Fax: 604-924-0918, Email: wjandrews@shaw.ca

October 17, 2015

British Columbia Hydro and Power Authority
333 Dunsmuir Street
Vancouver BC
V6B 5R3
Attn: Tom A. Loski, Chief Regulatory Officer
By email: bchydroregulatorygroup@bchydro.com

Dear Madam:

Re: British Columbia Hydro and Power Authority 2015 Rate Design Application (RDA);
BC Utilities Commission Order G-156-15;
BC Sustainable Energy Association and Sierra Club BC, Information Request No. 1

Attached please find a copy of BCSEA-SCBC's Information Request No. 1 to BC Hydro in this proceeding, filed on the Commission's website today.

BCSEA-SCBC have relatively few information requests at this time. As you know, BCSEA-SCBC participated fully in BC Hydro's 2015 RDA stakeholder engagement process, which is described in the Application. During the engagement process, BCSEA-SCBC obtained considerable information and explanation about the options that were evaluated and BC Hydro's reasons for its preferences as now reflected in the Application. In addition, BCSEA-SCBC have carefully reviewed the Commission's Information Request No. 1 (Exhibit A-5) and won't duplicate the Commission's questions.

BCSEA-SCBC look forward to BC Hydro's responses to the Commission's and interveners' information requests in accordance with the regulatory timetable.

Yours truly,

William J. Andrews

Barrister & Solicitor
Encl.
cc. Distribution List by email

REQUESTOR NAME: **BC Sustainable Energy Association and Sierra Club BC**
INFORMATION REQUEST ROUND NO: **1**
TO: **BC Hydro**
DATE: **November 17, 2015**
PROJECT NO: **n/a**
APPLICATION NAME: **BC Hydro 2015 Rate Design Application**

1.0 Topic: Legal framework
Reference: Exhibit B-1, p.1-1; section 2.2.1 Legal Regime

"The purpose of the Application is to update BC Hydro's default rate structures and Electric Tariff Terms and Conditions to reflect current conditions." [p.1-1]

On BC Hydro's website there is a page titled "Electric Tariff," at https://www.bchydro.com/about/planning_regulatory/tariff_filings/electric-tariff.html. The page provides explanation and links as follows:

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Electric Tariff
Electric tariff

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Additional terms and conditions of transmission voltage service are contained in Tariff Supplements 5 and 6.

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1.1 Do the files accessible from this webpage (https://www.bchydro.com/about/planning_regulatory/tariff_filings/electric-tariff.html) comprise all of "BC Hydro's default rate structures and Electric Tariff Terms and Conditions" to the extent addressed by the present Rate Design Application?

1.2 If the RDA addresses (i.e., seeks changes in or confirmation of) any aspects of BC Hydro's default rate structures and Electric Tariff Terms and Conditions that are not included within the documents provided at the website referred to in the preceding question, please identify them and provide web links (URLs) for them.

2.0 Topic: Terminology
Reference, Exhibit B-1, section 1.4 Rate Design Terminology

2.1 Please define "bill impact" as BC Hydro uses the term in the Application.

2.2 Please confirm that BC Hydro's use of the term "bill impact" in the Application differs from the traditional meaning of the term in that traditionally the bill impact of a rate design is zero if the customer bill is the same under the test rate design as under the status quo rate design assuming the same consumption, whereas in the Application if the customer bill is the same under the test rate design as under the status quo rate design assuming the same consumption then the bill impact of the test rate design equals the Class Average Rate Change (CARC).

3.0 Topic: Rate Rebalancing
Reference: Exhibit B-1, 2.2.1.3 Direction No. 7, the Heritage Contract and Rate Rebalancing

"On July 15, 2015 B.C. Reg. 140/2015 was deposited, amending section 9 of Direction No. 7 by providing that in setting rates for BC Hydro for F2017-F2019, the Commission must not set rates for the purposes of changing the R/C ratio for a class of customers (referred to as the **Rate Rebalancing Amendment**). As a result, BC Hydro is not proposing rate rebalancing as part of 2015 RDA Module 1." [p.2-7]

3.1 Does BC Hydro intend to consider rate rebalancing for the period beginning F2020? If so, what form will this take in terms of consultation and application for Commission approval? If not, why not?

4.0 Topic: Division of Street-Lighting Rate Class
Reference: Exhibit B-1, section 4.6, Street Lighting

4.1 Has BC Hydro received any feedback, subsequent to the 2015 RDA stakeholder engagement process reported in the Application, regarding its proposal to divide the Street-Lighting Rate Class into Customer-Owned Street-Lighting and BC Hydro-Owned Street-Lighting? If so, please provide a brief synopsis.

5.0 Topic: RIB Pricing Principles
Reference: Exhibit B-1, section 5.2.5.1; Table 5-2; s.1.1.3

"BC Hydro's preferred pricing principle for F2017-F2019 is to continue with the Order No. G-13-14 pricing principle of uniformly increasing the Step 1 energy, the Step 2 energy rate and the basic charge by the amount of the approved RRA rate increases effective April 1, 2016, 2017 and 2018" [Table 5-2]

5.1 If BC Hydro's proposed RIB Pricing Principles were approved as proposed, would they remain in place after F2017-F2019, that is, unless and until at some time in the future the Commission was to approve a change?

5.2 In BC Hydro's view, should the Commission approve permanent continuation of the Order No. G-13-14 pricing principle of uniformly increasing the Step 1 energy, the Step 2 energy rate and the basic charge by the amount of the approved RRA rate increases? Why or why not?

6.0 Topic: RIB Rate Conservation
Reference: Exhibit B-1, p.5-3

"The RIB is expected to have delivered approximately 480 GWh/year in cumulative conservation over the first ten years of implementation (October 2008 through F2017)." [underline added]

6.1 Please explain what "gigawatt hours per year" and "cumulative conservation" means in this context.

6.2 Please provide an analogy for 480 GWh/year in terms of, say, average annual household electricity consumption.

7.0 Topic: RIB Rate pricing principles
Reference: Exhibit B-1, section 5.2.5.1, F2017-F2019 Pricing Principles

"Option 1 (BC Hydro's proposal) would continue the Commission Order No. G-13-14 approach of applying RRA rate increases equally to all three RIB rate pricing elements. The effect of Option 1 would be to maintain the current differential in percentage terms between the Step 1 and Step 2 energy rates, and by extension, a Step 2 energy rate that currently exceeds the upper range of BC Hydro's LRMC. Since all components of the rates go up by the RRA rate while the DARR is forecasted to hold steady at 5 per cent for F2016 to F2019, the bill impacts for all customers is at the RRA rate increase (Direction No. 7 rate caps) in Table 5-8, as follows:..." [p.5-34, underline added]

7.1 Does BC Hydro agree that under the traditional definition of "bill impact" the Option 1 RIB Rate pricing principles has no bill impacts? And that, in contrast, all the alternative RIB rate pricing principles do have bill impacts?

8.0 Topic: RIB Rate, Flat Rate
Reference: Exhibit B-1, s.5.2.4.1

"3. Bill impacts are part of the Bonbright customer understanding and acceptance criterion. BC Hydro's primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers. As discussed at Workshop 9a, under a flat rate bills would go up for most customers, including low income customers, while

bills would go down for larger consuming residential customers. Figure 5-13 and Figure 5-14, and Table 5-3 and Table 5-4, illustrate the estimated bill impact distribution for flattening of the RIB rate in F2017 (relative to BC Hydro's RIB Pricing Principles):...
(b) Table 5-4 shows that only 9 per cent of low income customers would be better off under a flat rate as compared to the RIB rate;" underline added

8.1 How many Low Income Residential customers would be worse off under a flat rate as compared to the RIB rate? (i.e., the number as distinct from the percentage.)

8.2 Please provide an estimate of the number of people who are within the households of the Low Income Residential customers who would be worse off under a flat rate as compared to the RIB rate. If necessary, please assume that household size is same for Low Income Residential customers who would be worse off, and better off, under a flat rate as compared to the RIB rate.

"d) For typical customers consuming at about the median, the nominal bill increase from the status quo RIB rate is about $100 per year. A similar bill increase is also estimated for the median low income customer and the median low income customers with electric heat (Table 5-4)." [pp.5-23 to 5-24]

8.3 For the Low Income Residential customers who would be worse off under a flat rate as compared to the RIB rate, please provide the average nominal annual bill increase from the status quo RIB rate.

8.3.1 For the Low Income Residential customers who would be better off under a flat rate as compared to the RIB rate, please provide the average nominal annual bill decrease from the status quo RIB rate.

8.4 For the Electric Heat Residential customers who would be worse off under a flat rate as compared to the RIB rate, please provide the average nominal annual bill increase from the status quo RIB rate.

8.4.1 For the Electric Heat Residential customers who would be better off under a flat rate as compared to the RIB rate, please provide the average nominal annual bill decrease from the status quo RIB rate.

8.5 Where the terms "better off" and "worse off" are used on pages 5-22 to 5-24, is the 4.5% general rate increase included or excluded? Is a customer who is neither better off nor worse off, between a Flat rate and the RIB rate, a customer who has an annual bill increase of 4.5%?

8.5.1 Please confirm, or otherwise explain, that in Table 5-4 the column labeled "Median Bill of Segment" does include the 4.5% general rate increase, but in the column labeled "Median Bill Difference

from SQ" the general rate increase is netted out (because it applies to both the Flat rate scenario and RIB scenario).

9.0 Topic: E-Plus Rate
Reference: Exhibit B-1, section 5.3 Residential Dual Fuel Interruptible (E-Plus) Rate

9.1 Please explain why BC Hydro has chosen not to proceed with an option in which the E-Plus rate is phased out as of a date certain and in the meantime is amended to be non-interruptible.

10.0 Topic: RIB Rate Report Proceeding
Reference: Exhibit B-1, section 5.5, Methodologies for Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.47.2.1

"47.2 Please comment on the feasibility and usefulness of responding to the Minister's Question 3 for total household energy-use (i.e. all fuel sources)."

"47.2.1 What data, listed below, does BC Hydro have to examine total household energy use?
a) Data on number and amount of consumption of non-electric end-uses from the Residential End-Use Survey (REUS)?
b) Estimates of the cross-elasticity of demand between electricity and natural gas prices?
c) Other?"

10.1 Will the joint Conservation Potential Review being conducted by BC Hydro, FortisBC Energy Inc. (natural gas), and FortisBC Inc. (electricity) with involvement by Pacific Northern Gas (natural gas) produce information on total household energy-use (i.e. all fuel sources)?

10.2 What is the current status of the joint Conservation Potential Review?

10.3 When is the joint Conservation Potential Review expect to produce results? Would this be in time for the results to be used in the Commission's response to the Minister's RIB Rate letter?

11.0 Topic: RIB Rate Report Proceeding
Reference: Exhibit B-1, section 5.5.1.4, BC Hydro Residential Rate Modelling for Stakeholder Engagement; Exhibit A-5, BCUC IR 1.49.3

11.1 Does "a theoretical two-tier pricing system in which each and every resident experiences the same percentage of electricity consumption in Block 2" produce the same bill as a flat rate?

11.1.1 During the original proceeding regarding BC Hydro's then-proposed RIB rate was this potential design option considered for rate modelling and rejected because it is the equivalent of a flat rate?

11.1.2 Please confirm that the Residential rate design modelling that BC Hydro did for the 2015 RDA stakeholder engagement process includes a flat rate design.

12.0 Topic: RIB Rate Report Proceeding
Reference: Exhibit B-1, section 5.5, Methodologies for Minister Residential Inclining Block Rate Letter

12.1 Has BC Hydro received any directions or clarification from the Minister or Ministry regarding the response to the Minister's request for a report on the RIB rates? If so, please provide any such directions or clarification.

12.2 In BC Hydro's view, what is the scope of the report on the RIB rates in relation to BC Hydro residential electricity customers who are not served by BC Hydro's integrated system.

12.2.1 Does BC Hydro have any residential customers who are not served by the integrated system and who do have access to natural gas?

12.3 BC Hydro's material in sections 5.5 and 5.6 includes what could be called "results" in addition to "methodology." Please confirm that BC Hydro intends to provide a further report that will contain more comprehensive results than those provided in section 5.5 and 5.6.

12.4 The Minister's second question is "What evidence is available about high bill impacts [greater than 10 percent as a result of the adoption of the residential inclining block rates] on low income customers?" Please provide the definition of "bill impact" that BC Hydro will use in the RIB rates report.

13.0 Topic: RIB Rate Report Proceeding
Reference: Exhibit B-1, section 5.5.2, Defining Factors Leading to High Energy Use

"BC Hydro considered but rejected number of occupants as a factor. As noted in the 2014 REUS, while the average annual household consumption of electricity generally steps up with the number of individuals in the home, the number of household occupants is correlated with the physical size of the home in terms of floor area." [p.5-69]

13.1 Please explain the statement quoted above. Does BC Hydro propose to use floor area as a factor for the analysis? If higher than average annual electricity consumption is correlated with number of occupants then why not use number of occupants as one of the factors for analysis?

14.0 Topic: RIB Rate Report Proceeding
Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.49, cross-subsidy

14.1 Is there an alternative to a cost of service approach for the analysis of whether there is a cross-subsidy between customers within the same rate class? If so, please describe it and discuss whether it should be used for the RIB rates report in addition to a cost of service approach.

14.2 Further to BCUC IR 1.49.1.1, please comment on the usefulness of BC Hydro including in the report on the Minister's Question 1 a discussion of:

14.2.1 the extent to which each of the two categories of residential customer benefits from the Heritage Assets, and, if so, how this applies to FBC and whether this requires consideration of the Power Purchase Agreement, and

14.2.2 the postage stamp principle, and whether geographically related differences in the utility's cost of providing service are to be included, or excluded, from the analysis of cross-subsidization.

14.3 Further to BCUC IR 1.49.1.1, please confirm, or otherwise explain, that BC Hydro's report on whether there is intra-class cross-subsidization will not rely on the legal fact the Commission has already determined that the BC Hydro RIB rates are fair, reasonable and not unduly discriminatory under the *Act*, bearing in mind among other things the varying access to heating fuels among residential customers.

14.4 Further to BCUC IR 1.49.1.1, please comment on the usefulness of BC Hydro including in the report on the Minister's Question 1 a discussion of:

14.4.1 whether determining whether there is a cross-subsidy between the two groups is effectively reconsidering previous Commission decisions approving the BC Hydro and FBC RIB rates, and

14.4.2 the consequences or potential consequences if a cross-subsidy is found to exist.

15.0 Topic: RIB Rate Report Proceeding
Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.48, access to natural gas; BCUC IR1.49, cross-subsidy

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states on page 3 that:

> "BCSEA-SCBC do not disagree with BC Hydro's proposed use of a "community" definition of access to natural gas.
>
> It is noted, however, that the community approach [to defining 'access to natural gas'] yields a relatively small number of electricity customers being in the category of "without access to natural gas." BC Hydro lists as examples customers in Clearwater, Golden, Invermere, Port Hardy and Valemount.."

15.1 Does BC Hydro agree that the community approach to defining 'access to natural gas' yields a relatively small number of electricity customers being in the category of "without access to natural gas? If not, please explain. If so, is this a problem in terms of responding to the spirit of the Minister's request?

15.2 Would it be feasible to define "access to natural gas" in terms of the actual presence of natural gas appliances in the household? Could BC Hydro's REUS data on heating fuel types be used as a proxy for access to natural gas, defined in this way?

15.2.1 In BC Hydro's view, would such an approach correspond more closely to the intention of the Minister's request?

15.3 Please either provide a complete list of communities in BC Hydro's service territory that BC Hydro considers to be "without access to natural gas" for the purpose of the RIB rates report, or confirm that this information will be provided later in BC Hydro's full report.

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states further, on pages 3-4, that:

> "BCSEA-SCBC simply note that using the community definition means that the putative cross-subsidization is between (a) all of the residential electricity customers in the communities without natural gas, including customers who have electric heat and those who use other heating fuels, and (b) residential electricity customers in all other areas of the utility's service territory, including those who use electric heat, those who use natural gas for heating, and those who use other heating fuels. <u>This is very different than</u> an analysis in which "without access to natural gas" is defined as not having natural gas heating (space or water) in the premises for whatever reason. [footnote omitted] In the latter case, the cross-subsidization analysis is between (a) residential electricity customers who <u>don't</u> use natural gas heating (for whatever reason), and (b) residential electricity customers who <u>do</u> use natural gas heating. Unfortunately, it is not entirely clear which definition of "without access to natural gas" the Minister had in mind." [underline added]

15.4 Please provide BC Hydro's responses to the statements quoted above.

15.4.1 Does BC Hydro agree that the question of whether there is intra-class cross-subsidization between customers in (a) several communities such as Clearwater, Golden, Invermere, Port Hardy and Valemount and (b) all other parts of BC Hydro's service area is very different than the question of whether there is intra-class cross-subsidization between customers who (a) <u>don't</u> use natural gas heating (for whatever reason), and (b) <u>do</u> use natural gas heating?

15.4.2 Is it BC Hydro's view that the Minister's request contemplates a community approach to the definition of "without access to natural gas"?

16.0 Topic: RIB Rate Report Proceeding
Reference: Exhibit B-1, section 5.6, BC Hydro Residential Demand Side Management Programs

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states on page 6 that:

> "In BCSEA-SCBC's view, question 4 is not adequately answered by merely describing existing DSM programs (which is what might be inferred from the utilities' responses). BCSEA-SCBC recommend that the Commission clarify that the core of question 4 is what is the potential for existing DSM programs to reduce electricity usage and hence customer bills. For example, what is the potential for an existing DSM program to be ramped up, say with higher incentives, in order to achieve increased energy savings?"

16.1 Will BC Hydro include in its report to the Commission on the Minister's question an examination of the potential for existing DSM programs to reduce electricity usage and hence customer bills?

16.1.1 For example, will BC Hydro address the potential for an existing DSM program to be ramped up, say with higher incentives, in order to achieve increased energy savings?

16.2 Does BC Hydro agree that the Minister's Question 5 question 5 is not limited to customers without access to natural gas and asks for the Commission to report on options on additional DSM programs for residential customers generally and for low income residential customers, both within the context of the current regulatory environment? If not, why not?

16.3 Further to BC Hydro's statements on pages 5-72 and 5-73 regarding "the current regulatory environment" referred to in the Minister's Question 5, does BC Hydro agree that the DSM Regulation and sections 44.1 and 44.2 of the *Act* are the main factors? Please describe BC Hydro's understanding of "the current regulatory environment" referred to in the Minister's Question 5.

17.0 Topic: Small General Service Basic Charge
Reference: Exhibit B-1, section 6.2.3.2 SGS Basic Charge Cost Recovery

17.1 BC Hydro proposes raising the SGS Basic Charge from about 33% cost recovery to about 45% cost recovery. Please quantify the impact of this change on conservation. Please specify the elasticity assumptions used in the response.

18.0 Topic: Medium General Service, Large General Service, Conservation
Reference: Exhibit B-1, section 6.3 Medium General Service; section 6.4 Large General Service

BC Hydro proposes to change the existing two-part energy rates and three step demand rates for MGS and LGS to flat energy rate .

18.1 Further to BC Hydro's response to BCUC IR 1.56.1.1, does BC Hydro consider that the improved customer understanding associated with a flat rate would contribute to increased natural conservation? If so, can this be quantified?

18.2 Does BC Hydro have, or will it develop, a communications strategy for the change to flat MGS and LGS rates designed to foster increased conservation? What elements will be included?

18.3 Will BC Hydro develop new, or package existing, DSM measures for MGS and LGS customers aimed at maximizing the opportunity for the change to flat rates to be associated with increased conservation? If so, please describe. If not, why not?

18.4 Will BC Hydro identify MGS and LGS customers who have or would have had conservation opportunities under the existing rate structures that would be lost or impeded by a change to a flat rate? Will BC Hydro work with such customers to find ways to implement these conservation opportunities under a flat rate scenario?

18.5 BC Hydro proposes that the new MGS and LGS rate designs (flat energy and flat demand) would come into effect as of April 1, 2017. Does BC Hydro agree that one advantage of this effective date is that it gives BC Hydro roughly one year from the Commission's decision on the Application within which to develop and implement a strategy for maximizing the potential conservation opportunities inherent in the change to flat energy and demand rates?

19.0 Topic: LGS and MGS New Account Rule
Reference: Exhibit B-1, section 6.6, Requested Order for the LGS and MGS New Account Rule, p. 6-71

19.1 Would the proposed "100 per cent Part 1 Pricing" for New Accounts cause a cross-subsidy? If so, how large? If not, why not?

19.2 Would it be feasible for the New Account rate to be set on an interim and refundable basis at a rate that BC Hydro estimates would be equivalent to the proposed flat rates for LGS and MGS customers?

19.3 Please confirm, or otherwise explain, that the proposed "100 per cent Part 1 Pricing" for LGS and MGS New Accounts would expire when the proposed flat rates for LGS and MGS come into effect.

19.4 Is it BC Hydro's intention that proposed "100 per cent Part 1 Pricing" for LGS and MGS New Accounts would remain in place indefinitely if the Commission does not approve the flattening of the LGS and MGS rates?

20.0 Topic: Nomenclature
Reference: Exhibit B-1, Appendix B, Glossary and Abbreviations

20.1 Please provide a table showing for each of BC Hydro's rate schedules and tariff supplements, existing and proposed, the identification number (e.g., RS 1853), the common name (e.g., IPP Station Service), and a very brief description. The intention is to have a searchable reference for use in this proceeding. Obsolete rates could be omitted. Please also include informal terms such as RS 15xx. If BC Hydro already has a list of rate schedules and tariff supplements then please provide a copy of it instead of the requested table.

1.0 Topic: Legal framework

Reference: Exhibit B-1, p.1-1; section 2.2.1 Legal Regime

"The purpose of the Application is to update BC Hydro's default rate structures and Electric Tariff Terms and Conditions to reflect current conditions." [p.1-1]

On BC Hydro's website there is a page titled "Electric Tariff," at https://www.bchydro.com/about/planning_regulatory/tariff_filings/electric-tariff.html. The page provides explanation and links as follows:

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Tariff Supplement 82 – Rules for LGS Prospective Growth Applications [PDF, 9.9 MB]

1.1.1 Do the files accessible from this webpage (https://www.bchydro.com/about/planning_regulatory/tariff_filings/electric-tariff.html) comprise all of "BC Hydro's default rate structures and Electric Tariff Terms and Conditions" to the extent addressed by the present Rate Design Application?

RESPONSE:

Confirmed.

1.0 Topic: Legal framework

Reference: Exhibit B-1, p.1-1; section 2.2.1 Legal Regime

"The purpose of the Application is to update BC Hydro's default rate structures and Electric Tariff Terms and Conditions to reflect current conditions." [p.1-1]

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1.1.2 If the RDA addresses (i.e., seeks changes in or confirmation of) any aspects of BC Hydro's default rate structures and Electric Tariff Terms and Conditions that are not included within the documents provided at the website referred to in the preceding question, please identify them and provide web links (URLs) for them.

RESPONSE:

Please refer to BC Hydro's response to BCSEA IR 1.1.1.

2.0 Topic: Terminology

Reference: Exhibit B-1, section 1.4 Rate Design Terminology

1.2.1 Please define "bill impact" as BC Hydro uses the term in the Application.

RESPONSE:

BC Hydro defines bill impact as the percentage change in a customer's annual bill from one year to the next if consumption stays the same (Exhibit B-1, page 2-58, lines 8 to 9).

Consumption can be further defined as energy consumption (kWh) and demand (kW), if applicable.

2.0 Topic: Terminology

Reference: Exhibit B-1, section 1.4 Rate Design Terminology

1.2.2 Please confirm that BC Hydro's use of the term "bill impact" in the Application differs from the traditional meaning of the term in that traditionally the bill impact of a rate design is zero if the customer bill is the same under the test rate design as under the status quo rate design assuming the same consumption, whereas in the Application if the customer bill is the same under the test rate design as under the status quo rate design assuming the same consumption then the bill impact of the test rate design equals the Class Average Rate Change (CARC).

RESPONSE:

BC Hydro defined bill impact as the percentage change in a customer's annual bill from one year to the next if consumption stays the same in the following rate applications:

- **2008 RIB Application;**
- **2011 RIB Re-pricing Application;**
- **2013 RIB Re-pricing application; and**
- **2009 LGS Application.**

All customers under the existing RIB rate will have a bill impact equal to CARC, which is the same as RRA since the DARR is set at a constant 5 per cent.

3.0 Topic: Rate Rebalancing

Reference: Exhibit B-1, 2.2.1.3 Direction No. 7, the Heritage Contract and Rate Rebalancing

"On July 15, 2015 B.C. Reg. 140/2015 was deposited, amending section 9 of Direction No. 7 by providing that in setting rates for BC Hydro for F2017-F2019, the Commission must not set rates for the purposes of changing the R/C ratio for a class of customers (referred to as the **Rate Rebalancing Amendment**). As a result, BC Hydro is not proposing rate rebalancing as part of 2015 RDA Module 1." [p.2-7]

1.3.1 Does BC Hydro intend to consider rate rebalancing for the period beginning F2020? If so, what form will this take in terms of consultation and application for Commission approval? If not, why not?

RESPONSE:

As discussed at Workshop 12 and as described in section 3.1.2 of Exhibit B-1, BC Hydro proposes to review COS methodologies and file a F2019 COS study with the Commission for review in F2019. The F2019 COS would be the subject of stakeholder engagement prior to filing and would include a rate rebalancing proposal if appropriate.

4.0 Topic: Division of Street-Lighting Rate Class

Reference: Exhibit B-1, section 4.6, Street Lighting

1.4.1 Has BC Hydro received any feedback, subsequent to the 2015 RDA stakeholder engagement process reported in the Application, regarding its proposal to divide the Street-Lighting Rate Class into Customer-Owned Street-Lighting and BC Hydro-Owned Street-Lighting? If so, please provide a brief synopsis.

RESPONSE:

No.

5.0 Topic: RIB Pricing Principles

Reference: Exhibit B-1, section 5.2.5.1; Table 5-2; s.1.1.3

"BC Hydro's preferred pricing principle for F2017-F2019 is to continue with the Order No. G-13-14 pricing principle of uniformly increasing the Step 1 energy, the Step 2 energy rate and the basic charge by the amount of the approved RRA rate increases effective April 1, 2016, 2017 and 2018" [Table 5-2]

1.5.1 If BC Hydro's proposed RIB Pricing Principles were approved as proposed, would they remain in place after F2017-F2019, that is, unless and until at some time in the future the Commission was to approve a change?

RESPONSE:

No. Subject to the Commission's Decision on RIB rate F2017-F2019 pricing principles, BC Hydro would engage with stakeholders as to whether the F2017-F2019 RIB Pricing Principles remained appropriate for the post F2019 period and would file a RIB rate re-pricing application as necessary for pricing principles to apply beginning in F2020.

5.0 Topic: RIB Pricing Principles

Reference: Exhibit B-1, section 5.2.5.1; Table 5-2; s.1.1.3

"BC Hydro's preferred pricing principle for F2017-F2019 is to continue with the Order No. G-13-14 pricing principle of uniformly increasing the Step 1 energy, the Step 2 energy rate and the basic charge by the amount of the approved RRA rate increases effective April 1, 2016, 2017 and 2018" [Table 5-2]

1.5.2 In BC Hydro's view, should the Commission approve permanent continuation of the Order No. G-13-14 pricing principle of uniformly increasing the Step 1 energy, the Step 2 energy rate and the basic charge by the amount of the approved RRA rate increases? Why or why not?

RESPONSE:

Please refer to BC Hydro's response to BCSEA IR 1.5.1.

6.0 Topic: RIB Rate Conservation

Reference: Exhibit B-1, p.5-3

"The RIB is expected to have delivered approximately 480 GWh/year in cumulative conservation over the first ten years of implementation (October 2008 through F2017)." [underline added]

1.6.1 Please explain what "gigawatt hours per year" and "cumulative conservation" means in this context.

RESPONSE:

BC Hydro estimates that the total reduction in electricity consumption in response to the price changes attributable to the RIB rate structure, which occurred between the implementation of the RIB rate on October 1, 2008 and April 1, 2016 (F2017), is 480 GWh/year. It is explained in gigawatt hours per year, because that is the total GWh conserved in year F2017.

6.0 Topic: RIB Rate Conservation

Reference: Exhibit B-1, p.5-3

"The RIB is expected to have delivered approximately 480 GWh/year in cumulative conservation over the first ten years of implementation (October 2008 through F2017)." [underline added]

1.6.2 Please provide an analogy for 480 GWh/year in terms of, say, average annual household electricity consumption.

RESPONSE:

The 480 GWh/year represents the amount of consumption of about 64,000 homes.

7.0 Topic: RIB Rate pricing principles

Reference: Exhibit B-1, section 5.2.5.1, F2017-F2019 Pricing Principles

"Option 1 (BC Hydro's proposal) would continue the Commission Order No. G-13-14 approach of applying RRA rate increases equally to all three RIB rate pricing elements. The effect of Option 1 would be to maintain the current differential in percentage terms between the Step 1 and Step 2 energy rates, and by extension, a Step 2 energy rate that currently exceeds the upper range of BC Hydro's LRMC. Since all components of the rates go up by the RRA rate while the DARR is forecasted to hold steady at 5 per cent for F2016 to F2019, the bill impacts for all customers is at the RRA rate increase (Direction No. 7 rate caps) in Table 5-8, as follows:..." [p.5-34, underline added]

1.7.1 Does BC Hydro agree that under the traditional definition of "bill impact" the Option 1 RIB Rate pricing principles has no bill impacts? And that, in contrast, all the alternative RIB rate pricing principles do have bill impacts?

RESPONSE:

Option 1 continues with the existing F2015/16 RIB rate pricing principles, so all customer bills under this option will be the same as the existing RIB rate. The bill impacts of all customers, as defined at Exhibit B-1, page 2-58 lines 8 to 9, is projected to be CARC (which is the same as RRA since the DARR is projected to be held constant at 5 per cent for the duration of the modelling).

In contrast, RIB rate pricing principle Option 2 results in bill impacts that are either higher or lower than CARC depending on the consumption level.

8.0 Topic: RIB Rate, Flat Rate

Reference: Exhibit B-1, s.5.2.4.1

"3. Bill impacts are part of the Bonbright customer understanding and acceptance criterion. BC Hydro's primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers. As discussed at Workshop 9a, under a flat rate bills would go up for most customers, including low income customers, while bills would go down for larger consuming residential customers. Figure 5-13 and Figure 5-14, and Table 5-3 and Table 5-4, illustrate the estimated bill impact distribution for flattening of the RIB rate in F2017 (relative to BC Hydro's RIB Pricing Principles):...
(b) Table 5-4 shows that only 9 per cent of low income customers would be better off under a flat rate as compared to the RIB rate;" underline added

1.8.1 How many Low Income Residential customers would be worse off under a flat rate as compared to the RIB rate? (i.e., the number as distinct from the percentage.)

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates that about 137,701 accounts are worse off under the alternative flat rate as compared to the default RIB rate in F2017.

8.0 Topic: RIB Rate, Flat Rate

Reference: Exhibit B-1, s.5.2.4.1

"3. Bill impacts are part of the Bonbright customer understanding and acceptance criterion. BC Hydro's primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers. As discussed at Workshop 9a, under a flat rate bills would go up for most customers, including low income customers, while bills would go down for larger consuming residential customers. Figure 5-13 and Figure 5-14, and Table 5-3 and Table 5-4, illustrate the estimated bill impact distribution for flattening of the RIB rate in F2017 (relative to BC Hydro's RIB Pricing Principles):...
(b) Table 5-4 shows that only 9 per cent of low income customers would be better off under a flat rate as compared to the RIB rate;" underline added

1.8.2 Please provide an estimate of the number of people who are within the households of the Low Income Residential customers who would be worse off under a flat rate as compared to the RIB rate. If necessary, please assume that household size is same for Low Income Residential customers who would be worse off, and better off, under a flat rate as compared to the RIB rate.

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates that about 306,675 people residing in low income households would be worse off on the alternative flat rate compared to default RIB rate for F2017.

8.0 Topic: RIB Rate, Flat Rate

Reference: Exhibit B-1, s.5.2.4.1

"3. Bill impacts are part of the Bonbright customer understanding and acceptance criterion. BC Hydro's primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers. As discussed at Workshop 9a, under a flat rate bills would go up for most customers, including low income customers, while bills would go down for larger consuming residential customers. Figure 5-13 and Figure 5-14, and Table 5-3 and Table 5-4, illustrate the estimated bill impact distribution for flattening of the RIB rate in F2017 (relative to BC Hydro's RIB Pricing Principles):...
(b) Table 5-4 shows that only 9 per cent of low income customers would be better off under a flat rate as compared to the RIB rate;" underline added

"d) For typical customers consuming at about the median, the nominal bill increase from the status quo RIB rate is about $100 per year. A similar bill increase is also estimated for the median low income customer and the median low income customers with electric heat (Table 5-4)." [pp.5-23 to 5-24]

1.8.3 For the Low Income Residential customers who would be worse off under a flat rate as compared to the RIB rate, please provide the average nominal annual bill increase from the status quo RIB rate.

RESPONSE:

The average bill increase estimated for low income accounts that would be worse off on the alternative flat rate compared to the default RIB rate is 13.2 per cent.

8.0 Topic: RIB Rate, Flat Rate

Reference: Exhibit B-1, s.5.2.4.1

"3. Bill impacts are part of the Bonbright customer understanding and acceptance criterion. BC Hydro's primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers. As discussed at Workshop 9a, under a flat rate bills would go up for most customers, including low income customers, while bills would go down for larger consuming residential customers. Figure 5-13 and Figure 5-14, and Table 5-3 and Table 5-4, illustrate the estimated bill impact distribution for flattening of the RIB rate in F2017 (relative to BC Hydro's RIB Pricing Principles):...
(b) Table 5-4 shows that only 9 per cent of low income customers would be better off under a flat rate as compared to the RIB rate;" underline added

"d) For typical customers consuming at about the median, the nominal bill increase from the status quo RIB rate is about $100 per year. A similar bill increase is also estimated for the median low income customer and the median low income customers with electric heat (Table 5-4)." [pp.5-23 to 5-24]

1.8.3.1 For the Low Income Residential customers who would be <u>better</u> off under a flat rate as compared to the RIB rate, please provide the average nominal annual bill decrease from the status quo RIB rate.

RESPONSE:

The average bill <u>decrease</u> estimated for low income accounts that would be better off on the alternative flat rate compared to the default RIB rate is 5.4 per cent.

8.0 Topic: RIB Rate, Flat Rate

Reference: Exhibit B-1, s.5.2.4.1

"3. Bill impacts are part of the Bonbright customer understanding and acceptance criterion. BC Hydro's primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers. As discussed at Workshop 9a, under a flat rate bills would go up for most customers, including low income customers, while bills would go down for larger consuming residential customers. Figure 5-13 and Figure 5-14, and Table 5-3 and Table 5-4, illustrate the estimated bill impact distribution for flattening of the RIB rate in F2017 (relative to BC Hydro's RIB Pricing Principles):...
(b) Table 5-4 shows that only 9 per cent of low income customers would be better off under a flat rate as compared to the RIB rate;" underline added

1.8.4 For the Electric Heat Residential customers who would be worse off under a flat rate as compared to the RIB rate, please provide the average nominal annual bill increase from the status quo RIB rate.

RESPONSE:

The average bill increase estimated for Electric Heat accounts that would be worse off on the alternative flat rate compared to the default RIB rate is 11.8 per cent.

8.0 Topic: RIB Rate, Flat Rate

Reference: Exhibit B-1, s.5.2.4.1

"3. Bill impacts are part of the Bonbright customer understanding and acceptance criterion. BC Hydro's primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers. As discussed at Workshop 9a, under a flat rate bills would go up for most customers, including low income customers, while bills would go down for larger consuming residential customers. Figure 5-13 and Figure 5-14, and Table 5-3 and Table 5-4, illustrate the estimated bill impact distribution for flattening of the RIB rate in F2017 (relative to BC Hydro's RIB Pricing Principles):...
(b) Table 5-4 shows that only 9 per cent of low income customers would be better off under a flat rate as compared to the RIB rate;" underline added

1.8.4.1 For the Electric Heat Residential customers who would be <u>better</u> off under a flat rate as compared to the RIB rate, please provide the average nominal annual bill decrease from the status quo RIB rate.

RESPONSE:

The average bill <u>decrease</u> estimated for Electric Heat accounts that would be better off on the alternative flat rate compared to the default RIB rate is 6.4 per cent.

8.0 Topic: RIB Rate, Flat Rate

Reference: Exhibit B-1, s.5.2.4.1

"3. Bill impacts are part of the Bonbright customer understanding and acceptance criterion. BC Hydro's primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers. As discussed at Workshop 9a, under a flat rate bills would go up for most customers, including low income customers, while bills would go down for larger consuming residential customers. Figure 5-13 and Figure 5-14, and Table 5-3 and Table 5-4, illustrate the estimated bill impact distribution for flattening of the RIB rate in F2017 (relative to BC Hydro's RIB Pricing Principles):...
(b) Table 5-4 shows that only 9 per cent of low income customers would be better off under a flat rate as compared to the RIB rate;" underline added

1.8.5 Where the terms "better off" and "worse off" are used on pages 5-22 to 5-24, is the 4.5% general rate increase included or excluded? Is a customer who is neither better off nor worse off, between a Flat rate and the RIB rate, a customer who has an annual bill increase of 4.5%?

RESPONSE:

As shown in Exhibit B-1, Appendix H-1A, Table H-1A-1, the process involved in modelling the Residential F2017 forecasted revenue, which is used to calculate all of the F2017 Residential rates shown in Exhibit B-1, involves the use of the F2017 RRA of 4 per cent. The use of 4 per cent for F2017 results from section 9 of Direction No. 7.

BC Hydro uses the terms "better off" and "worse off" in reference to annual bills under an alternative design that are lower than, or higher than, they would be under the existing RIB rate. Exhibit B-1, Table 5-4 shows the proportions of the "better off" customers who would have F2017 annual bills that are at least 1 per cent lower under the flat rate than the existing RIB rate.

The bill impacts of all customers under the existing F2017 RIB rate is at the RRA of 4 per cent. In comparison, if the flat rate is implemented in F2017, customers who experience a bill impact:

- **higher than the RRA will have a higher annual bill under the flat rate and can generally be considered "worse off";**
- **lower than the RRA will have a lower annual bill under the flat rate and can generally be considered "better off"; and**
- **equal to the RRA will have the same bill under the flat rate and can generally be considered nether "worse off" nor "better off".**

8.0 Topic: RIB Rate, Flat Rate

Reference: Exhibit B-1, s.5.2.4.1

"3. Bill impacts are part of the Bonbright customer understanding and acceptance criterion. BC Hydro's primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers. As discussed at Workshop 9a, under a flat rate bills would go up for most customers, including low income customers, while bills would go down for larger consuming residential customers. Figure 5-13 and Figure 5-14, and Table 5-3 and Table 5-4, illustrate the estimated bill impact distribution for flattening of the RIB rate in F2017 (relative to BC Hydro's RIB Pricing Principles):...
(b) Table 5-4 shows that only 9 per cent of low income customers would be better off under a flat rate as compared to the RIB rate;" underline added

1.8.5.1 Please confirm, or otherwise explain, that in Table 5-4 the column labeled "Median Bill of Segment" does include the 4.5% general rate increase, but in the column labeled "Median Bill Difference from SQ" the general rate increase is netted out (because it applies to both the Flat rate scenario and RIB scenario).

RESPONSE:

Not confirmed.

As shown in Exhibit B-1, Appendix H-1A, Table H-1A-1, the process involved in modelling the Residential F2017 forecasted revenue, which is used to calculate all of F2017 Residential rates shown in Exhibit B-1, involves the use of the F2017 RRA of 4 per cent.

The "Median bill of segment" is calculated using the F2017 flat rate.

The "Median Bill Difference from SQ" is calculated as follows:

Median Bill Difference from SQ = (Annual bill of median customer under the F2017 flat rate) - (Annual bill of median customer under the F2017 existing RIB rate)

The outcome of the subtraction above illustrates how much higher the median customer's annual bill will likely be under the flat rate, relative to the existing RIB rate. The subtraction does not "net out" the RRA, which is the general rate increase between F2016 and F2017.

9.0 Topic: E-Plus Rate

Reference: Exhibit B-1, section 5.3 Residential Dual Fuel Interruptible (E-Plus) Rate

1.9.1 Please explain why BC Hydro has chosen not to proceed with an option in which the E-Plus rate is phased out as of a date certain and in the meantime is amended to be non-interruptible.

RESPONSE:

BC Hydro rejected Option 2 – to phase out the E-Plus rate over a period of time (e.g., five to 10 years) after which customers would pay the default rate for their rate class for all consumption – on the basis of large bill impacts to E-Plus customers. As highlighted in Table 5 of section 2.3.4 on page 254 of 609 of the Workshop 9a/9b Discussion Guide, attached in Appendix C-3B of Exhibit B-1, the expected median bill increase of ending the E-Plus rate (not including general rate increases) is about 40 per cent. This rejection holds whether or not the phase-out is preceded by making the rate truly interruptible.

10.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5, Methodologies for Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.47.2.1

"47.2 Please comment on the feasibility and usefulness of responding to the Minister's Question 3 for total household energy-use (i.e. all fuel sources)."

"47.2.1 What data, listed below, does BC Hydro have to examine total household energy use?

a) Data on number and amount of consumption of non-electric end-uses from the Residential End-Use Survey (REUS)?

b) Estimates of the cross-elasticity of demand between electricity and natural gas prices?

c) Other?"

1.10.1 Will the joint Conservation Potential Review being conducted by BC Hydro, FortisBC Energy Inc. (natural gas), and FortisBC Inc. (electricity) with involvement by Pacific Northern Gas (natural gas) produce information on total household energy-use (i.e. all fuel sources)?

RESPONSE:

This response addresses BCSEA IRs 1.10.1, 1.10.2 and 1.10.3.

BC Hydro is working with FortisBC Energy Inc. (natural gas) and FortisBC Inc. (electricity) with involvement by Pacific Northern Gas to conduct a joint CPR. The CPR project has recently started and as such, project milestones are still being confirmed, but it is expected that there will be results available in F2017.

The CPR will produce information on residential household energy use with respect to electricity and natural gas, both at a provincial and regional level. However, CPR data is not at a granular level that would be required to respond to the Minister RIB Letter Question 3. For BC Hydro's views on the approach to the Minister RIB Letter Question 3, please refer to BC Hydro's response to BCUC IR 1.47.1.1.

10.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5, Methodologies for Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.47.2.1

"47.2 Please comment on the feasibility and usefulness of responding to the Minister's Question 3 for total household energy-use (i.e. all fuel sources)."

"47.2.1 What data, listed below, does BC Hydro have to examine total household energy use?

a) Data on number and amount of consumption of non-electric end-uses from the Residential End-Use Survey (REUS)?

b) Estimates of the cross-elasticity of demand between electricity and natural gas prices?

c) Other?"

1.10.2 What is the current status of the joint Conservation Potential Review?

RESPONSE:

Please refer to BC Hydro's response to BCSEA IR 1.10.1.

10.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5, Methodologies for Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.47.2.1

"47.2 Please comment on the feasibility and usefulness of responding to the Minister's Question 3 for total household energy-use (i.e. all fuel sources)."

"47.2.1 What data, listed below, does BC Hydro have to examine total household energy use?

a) Data on number and amount of consumption of non-electric end-uses from the Residential End-Use Survey (REUS)?

b) Estimates of the cross-elasticity of demand between electricity and natural gas prices?

c) Other?"

1.10.3 When is the joint Conservation Potential Review expect to produce results? Would this be in time for the results to be used in the Commission's response to the Minister's RIB Rate letter?

RESPONSE:

Please refer to BC Hydro's response to BCSEA IR 1.10.1.

11.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.1.4, BC Hydro Residential Rate Modelling for Stakeholder Engagement; Exhibit A-5, BCUC IR 1.49.3

1.11.1 Does "a theoretical two-tier pricing system in which each and every resident experiences the same percentage of electricity consumption in Block 2" produce the same bill as a flat rate?

RESPONSE:

Yes, please refer to BC Hydro's response to BCUC IR 1.49.3.

11.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.1.4, BC Hydro Residential Rate Modelling for Stakeholder Engagement; Exhibit A-5, BCUC IR 1.49.3

1.11.1.1 During the original proceeding regarding BC Hydro's then-proposed RIB rate was this potential design option considered for rate modelling and rejected because it is the equivalent of a flat rate?

RESPONSE:

No.

11.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.1.4, BC Hydro Residential Rate Modelling for Stakeholder Engagement; Exhibit A-5, BCUC IR 1.49.3

1.11.1.2 Please confirm that the Residential rate design modelling that BC Hydro did for the 2015 RDA stakeholder engagement process includes a flat rate design.

RESPONSE:

Confirmed.

12.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5, Methodologies for Minister Residential Inclining Block Rate Letter

1.12.1 Has BC Hydro received any directions or clarification from the Minister or Ministry regarding the response to the Minister's request for a report on the RIB rates? If so, please provide any such directions or clarification.

RESPONSE:

BC Hydro has not received any directions or clarifications from the Minister or MEM regarding the response to the Minister RIB Report letter.

12.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5, Methodologies for Minister Residential Inclining Block Rate Letter

1.12.2 In BC Hydro's view, what is the scope of the report on the RIB rates in relation to BC Hydro residential electricity customers who are not served by BC Hydro's integrated system.

RESPONSE:

In BC Hydro's view, the Minister RIB Report Letter and the Commission's RIB Report do not encompass Zone II or Zone IB rates because Residential customers in Zone II and Zone IB are not served on the RIB rate (RS 1101/1121):

- **Zone II Residential customers are served pursuant to RS 1107/RS 1127 (Residential Service – Zone II) and RS 1148 (Residential Service – Zone II (Closed)); and**
- **Zone IB Residential customers are served pursuant to RS 1151/RS 1161 (Exempt Residential Service).**

Please also refer to BC Hydro's response to BCUC IR 1.51.1.

12.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5, Methodologies for Minister Residential Inclining Block Rate Letter

1.12.2.1 Does BC Hydro have any residential customers who are not served by the integrated system and who do have access to natural gas?

RESPONSE:

As set out in BC Hydro's response to BCSEA IR 1.12.2, the Minister RIB Report Letter and the Commission's RIB Report do not encompass Zone II or Zone IB rates because Residential customers in Zone II and Zone IB are not served on the RIB rate (RS 1101/1121). Accordingly, BC Hydro respectfully declines to respond to this IR.

12.0 Topic: **RIB Rate Report Proceeding**

Reference: **Exhibit B-1, section 5.5, Methodologies for Minister Residential Inclining Block Rate Letter**

1.12.3 BC Hydro's material in sections 5.5 and 5.6 includes what could be called "results" in addition to "methodology." Please confirm that BC Hydro intends to provide a further report that will contain more comprehensive results than those provided in section 5.5 and 5.6.

RESPONSE:

Confirmed.

12.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5, Methodologies for Minister Residential Inclining Block Rate Letter

1.12.4 The Minister's second question is "What evidence is available about high bill impacts [greater than 10 percent as a result of the adoption of the residential inclining block rates] on low income customers?" Please provide the definition of "bill impact" that BC Hydro will use in the RIB rates report.

RESPONSE:

BC Hydro will use the same definition of bill impact for RIB Report purposes that it is using for the 2015 RDA, as described in section 2.4.1.1 of Exhibit B-1, pages 2-58 to 2-59.

As discussed at the reference above, since the 2008 RIB Decision BC Hydro has used a 10 per cent maximum impact test inclusive of 'all-in' costs consisting of: RRA increases, the DARR and rate changes due to rate design. However, given the Rate Rebalancing Amendment discussed in section 2.2.1.3 of Exhibit B-1, rate rebalancing is not included in the 10 per cent bill impact test.

13.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.2, Defining Factors Leading to High Energy Use

"BC Hydro considered but rejected number of occupants as a factor. As noted in the 2014 REUS, while the average annual household consumption of electricity generally steps up with the number of individuals in the home, the number of household occupants is correlated with the physical size of the home in terms of floor area." [p.5-69]

1.13.1 Please explain the statement quoted above. Does BC Hydro propose to use floor area as a factor for the analysis? If higher than average annual electricity consumption is correlated with number of occupants then why not use number of occupants as one of the factors for analysis?

RESPONSE:

BC Hydro's statement that it considered but rejected number of occupants as a factor should be interpreted to mean that the number of occupants is confounding with the size of the home; using both parameters concurrently as explanatory variables in determining consumption could be problematic. From a statistics and modelling perspective, since the two parameters are correlated, there will be at least some multi-colinearity in a regression model.

14.0 Topic: **RIB Rate Report Proceeding**

Reference: **Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.49, cross-subsidy**

1.14.1 Is there an alternative to a cost of service approach for the analysis of whether there is a cross-subsidy between customers within the same rate class? If so, please describe it and discuss whether it should be used for the RIB rates report in addition to a cost of service approach.

RESPONSE:

In BC Hydro's view, there is no reasonable alternative to a cost of service approach for the analysis of the possibility the RIB rate is causing "cross-subsidy between customers with and without access to natural gas":

- **As noted in the article by D.A. Heald cited by FortisBC in its RIB Report methodology submission,[1] cross subsidies are hard to define, in part because they are hard to measure. Cross-subsidy in the rate design context is a Bonbright fair apportionment of costs among customers criterion issue. BC Hydro submits that an objective test – because it is transparent, and allows for modelling and analysis – is necessary. Cost causality is an objective and measurable way to address Minister RIB Report Letter Question 1;**

- **Only CEC[2] and Mr. Marty[3] appear to differ on BC Hydro's suggested approach to this issue:**

  - **CEC submits that the cross-subsidy issue should be addressed through a broader, subjective meaning of fairness. CEC advocates for a 'total bill' assessment. For the reasons set out in BC Hydro's response to BCUC IR 1.47.1.1, this is not feasible; and**

  - **Mr. Marty states that Minister RIB Report Letter Question 1 can only be answered "by comparing the revenue flows under the [respective utilities' residential inclining block rates], as currently structured, with a theoretical two-tier pricing system in which each and every resident experiences the same percentage of electricity consumption in Block 2". In BC Hydro's view, this would require BC Hydro Residential customer-specific baselines, which is not practical for the reasons set out in Exhibit B-1, page 5-20, lines 17 to 20.**

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1 FortisBC RIB Report submission, September 30, 2015, page 3; http://www.bcuc.com/Documents/Arguments/2015/DOC_44718_09-30-2015_FBC-Submission.pdf.

2 CEC RIB Report submission, October 16, 2015, page 3; http://www.bcuc.com/Documents/Arguments/2015/DOC_44881_10-16-2015_CEC_Submission-on-Methodologies.pdf.

3 Mr. Marty RIB Report submission, October 13, 2015, page 2; http://www.bcuc.com/Documents/Arguments/2015/DOC_44836_10-13-2015_MartyN_Stakeholder-Submission.pdf.

14.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.49, cross-subsidy

1.14.2 Further to BCUC IR 1.49.1.1, please comment on the usefulness of BC Hydro including in the report on the Minister's Question 1 a discussion of:

1.14.2.1 the extent to which each of the two categories of residential customer benefits from the Heritage Assets, and, if so, how this applies to FBC and whether this requires consideration of the Power Purchase Agreement, and

RESPONSE:

BC Hydro would consider there to be limited use in a separate discussion of the extent to which each of the two categories of Residential customers benefits from the Heritage Assets. That is, the discussion of whether a cross subsidy exists will capture any relative difference in the recovery of energy costs as between the two categories of Residential customers.

14.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.49, cross-subsidy

1.14.2 Further to BCUC IR 1.49.1.1, please comment on the usefulness of BC Hydro including in the report on the Minister's Question 1 a discussion of:

1.14.2.2 the postage stamp principle, and whether geographically related differences in the utility's cost of providing service are to be included, or excluded, from the analysis of cross-subsidization.

RESPONSE:

In BC Hydro's view there is no utility in commenting on the postage stamp principle itself as part of responding to the Minister RIB Report Letter. The postage stamp principle must be taken as a given for both the 2015 RDA and Minister RIB Report Letter because postage stamp rate making has been confirmed as B.C. Government policy. In this regard refer to the MEM Policy Letter, copy found at Appendix C-1C of Exhibit B-1.

BC Hydro's proposed cost of service approach to assessing whether the RIB rate is potentially causing a cross subsidy between customers with and without natural gas service entails an examination of the costs associated with heating fuel type and not geographically-related differences.

14.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.49, cross-subsidy

1.14.3 Further to BCUC IR 1.49.1.1, please confirm, or otherwise explain, that BC Hydro's report on whether there is intra-class cross-subsidization will not rely on the legal fact the Commission has already determined that the BC Hydro RIB rates are fair, reasonable and not unduly discriminatory under the Act, bearing in mind among other things the varying access to heating fuels among residential customers.

RESPONSE:

In BC Hydro's view, past Commission decisions concerning BC Hydro's RIB rate, including the 2008 RIB Decision finding that BC Hydro's Residential electric heat customers are not unduly discriminated against as a result of the RIB rate,[1] are relevant to the RIB Report process.

Nevertheless, as indicated in section 5.5.3 of Exhibit B-1, BC Hydro will assess the possibility of the RIB rate causing "cross-subsidy between customers with and without access to natural gas", and evidence that the RIB rate may be causing high bill impacts (greater than 10 per cent) on BC Hydro's customers without access to natural gas by examining the bill impacts of:

- **The two RIB rate pricing principles on customers without access to natural gas. As noted in BC Hydro's response to BCUC IR 1.51.1, the answer is no under either of the two RIB rate F2017-F2019 pricing principle options discussed in section 5.2.5.1 of Exhibit B-1 if BC Hydro uses customers whose primary space heating source is electricity as a proxy for customers without access to natural gas;**

- **Moving from the RIB rate to a flat rate for communities that do not have access to natural gas. BC Hydro anticipates providing this modelling as part of its responses to Round 2 IRs provided the Commission decides on a definition of "customers without access to natural gas" on or before the end of January 2016.**

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[1] *In the Matter of British Columbia Hydro and Power Authority: Residential Inclining Block Application*, Reasons for Decision to Order No. G-124-08, September 24, 2008, page 80; http://www.bcuc.com/Documents/Proceedings/2008/DOC_19754_BCH-RIB-Decision-WEB.pdf.

14.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.49, cross-subsidy

1.14.4 Further to BCUC IR 1.49.1.1, please comment on the usefulness of BC Hydro including in the report on the Minister's Question 1 a discussion of:

1.14.4.1 whether determining whether there is a cross-subsidy between the two groups is effectively reconsidering previous Commission decisions approving the BC Hydro and FBC RIB rates, and

RESPONSE:

As noted in BC Hydro's response to BCSEA IR 1.14.3, in BC Hydro's view prior Commission decisions concerning BC Hydro's RIB rate are relevant to the examination of the possibility the RIB rate is causing "cross-subsidy between customers with and without access to natural gas". Accordingly, BC Hydro will be including a discussion of these prior Commission decisions in its utility report to the Commission.

14.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.49, cross-subsidy

1.14.4 Further to BCUC IR 1.49.1.1, please comment on the usefulness of BC Hydro including in the report on the Minister's Question 1 a discussion of:

1.14.4.2 the consequences or potential consequences if a cross-subsidy is found to exist.

RESPONSE:

Yes, BC Hydro is of the view that such a discussion would be useful.

15.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.48, access to natural gas; BCUC IR1.49, cross-subsidy

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states on page 3 that:

> "BCSEA-SCBC do not disagree with BC Hydro's proposed use of a "community" definition of access to natural gas.
>
> It is noted, however, that the community approach [to defining 'access to natural gas'] yields a relatively small number of electricity customers being in the category of "without access to natural gas." BC Hydro lists as examples customers in Clearwater, Golden, Invermere, Port Hardy and Valemount.."

1.15.1 Does BC Hydro agree that the community approach to defining 'access to natural gas' yields a relatively small number of electricity customers being in the category of "without access to natural gas? If not, please explain. If so, is this a problem in terms of responding to the spirit of the Minister's request?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.48.2.

15.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.48, access to natural gas; BCUC IR1.49, cross-subsidy

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states on page 3 that:

> "BCSEA-SCBC do not disagree with BC Hydro's proposed use of a "community" definition of access to natural gas.
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> It is noted, however, that the community approach [to defining 'access to natural gas'] yields a relatively small number of electricity customers being in the category of "without access to natural gas." BC Hydro lists as examples customers in Clearwater, Golden, Invermere, Port Hardy and Valemount.."

1.15.2 Would it be feasible to define "access to natural gas" in terms of the actual presence of natural gas appliances in the household? Could BC Hydro's REUS data on heating fuel types be used as a proxy for access to natural gas, defined in this way?

RESPONSE:

As noted in BC Hydro's response to BCUC IR 1.48.1, BC Hydro does not believe it is feasible to adopt the definition of "access to natural gas" in this way.

However, if "access to natural gas" was accepted as being the actual presence of natural gas appliances in the household, then yes, the REUS data could be used as a proxy.

15.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.48, access to natural gas; BCUC IR1.49, cross-subsidy

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states on page 3 that:

> "BCSEA-SCBC do not disagree with BC Hydro's proposed use of a "community" definition of access to natural gas.
>
> It is noted, however, that the community approach [to defining 'access to natural gas'] yields a relatively small number of electricity customers being in the category of "without access to natural gas." BC Hydro lists as examples customers in Clearwater, Golden, Invermere, Port Hardy and Valemount.."

1.15.2.1 In BC Hydro's view, would such an approach correspond more closely to the intention of the Minister's request?

RESPONSE:

No. Please refer to BC Hydro's response to BCSEA IR 1.15.2 and to BCUC IRs 1.48.1 and 1.48.2.

15.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.48, access to natural gas; BCUC IR1.49, cross-subsidy

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states on page 3 that:

> "BCSEA-SCBC do not disagree with BC Hydro's proposed use of a "community" definition of access to natural gas.
>
> It is noted, however, that the community approach [to defining 'access to natural gas'] yields a relatively small number of electricity customers being in the category of "without access to natural gas." BC Hydro lists as examples customers in Clearwater, Golden, Invermere, Port Hardy and Valemount.."

1.15.3 Please either provide a complete list of communities in BC Hydro's service territory that BC Hydro considers to be "without access to natural gas" for the purpose of the RIB rates report, or confirm that this information will be provided later in BC Hydro's full report.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.48.2.

15.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.48, access to natural gas; BCUC IR1.49, cross-subsidy

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states on page 3 that:

> "BCSEA-SCBC do not disagree with BC Hydro's proposed use of a "community" definition of access to natural gas.
>
> It is noted, however, that the community approach [to defining 'access to natural gas'] yields a relatively small number of electricity customers being in the category of "without access to natural gas." BC Hydro lists as examples customers in Clearwater, Golden, Invermere, Port Hardy and Valemount.."

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states further, on pages 3-4, that:

> "BCSEA-SCBC simply note that using the community definition means that the putative cross-subsidization is between (a) all of the residential electricity customers in the communities without natural gas, including customers who have electric heat and those who use other heating fuels, and (b) residential electricity customers in all other areas of the utility's service territory, including those who use electric heat, those who use natural gas for heating, and those who use other heating fuels. <u>This is very different than</u> an analysis in which "without access to natural gas" is defined as not having natural gas heating (space or water) in the premises for whatever reason. [footnote omitted] In the latter case, the cross-subsidization analysis is between (a) residential electricity customers who <u>don't</u> use natural gas heating (for whatever reason), and (b) residential electricity customers who <u>do</u> use natural gas heating. Unfortunately, it is not entirely clear which definition of "without access to natural gas" the Minister had in mind." [underline added]

1.15.4 Please provide BC Hydro's responses to the statements quoted above.

RESPONSE:

As described in section 5.5.3 of Exhibit B-1, BC Hydro supports containing the definition of "without access to natural gas" to a community level as in BC Hydro's view this is the only practical approach. Expanding beyond this would require much more granular information than BC Hydro has available to it. In this regard, please refer to BC Hydro's response to BCUC IR 1.48.2.

15.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.48, access to natural gas; BCUC IR1.49, cross-subsidy

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> "BCSEA-SCBC do not disagree with BC Hydro's proposed use of a "community" definition of access to natural gas.
>
> It is noted, however, that the community approach [to defining 'access to natural gas'] yields a relatively small number of electricity customers being in the category of "without access to natural gas." BC Hydro lists as examples customers in Clearwater, Golden, Invermere, Port Hardy and Valemount.."

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> "BCSEA-SCBC simply note that using the community definition means that the putative cross-subsidization is between (a) all of the residential electricity customers in the communities without natural gas, including customers who have electric heat and those who use other heating fuels, and (b) residential electricity customers in all other areas of the utility's service territory, including those who use electric heat, those who use natural gas for heating, and those who use other heating fuels. <u>This is very different than</u> an analysis in which "without access to natural gas" is defined as not having natural gas heating (space or water) in the premises for whatever reason. [footnote omitted] In the latter case, the cross-subsidization analysis is between (a) residential electricity customers who <u>don't</u> use natural gas heating (for whatever reason), and (b) residential electricity customers who <u>do</u> use natural gas heating. Unfortunately, it is not entirely clear which definition of "without access to natural gas" the Minister had in mind." [underline added]

1.15.4.1 Does BC Hydro agree that the question of whether there is intra-class cross-subsidization between customers in (a) several communities such as Clearwater, Golden, Invermere, Port Hardy and Valemount and (b) all other parts of BC Hydro's service area is very different than the question of whether there is intra-class cross-subsidization between customers who (a) <u>don't</u> use natural gas heating (for whatever reason), and (b) <u>do</u> use natural gas heating?

RESPONSE:

BC Hydro is unable to agree that the two approaches set out in the IR are very different questions that will lead to very different results. As set out in BC Hydro's response to BCUC IR 1.48.2 and BCSEA IR 1.15.4, in BC Hydro's view a community-based definition of customers without access to natural gas is the only practical approach.

15.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.5.3, Approach to Address Minister Residential Inclining Block Rate Letter; Exhibit A-5, BCUC IR 1.48, access to natural gas; BCUC IR1.49, cross-subsidy

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states on page 3 that:

> "BCSEA-SCBC do not disagree with BC Hydro's proposed use of a "community" definition of access to natural gas.
>
> It is noted, however, that the community approach [to defining 'access to natural gas'] yields a relatively small number of electricity customers being in the category of "without access to natural gas." BC Hydro lists as examples customers in Clearwater, Golden, Invermere, Port Hardy and Valemount.."

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states further, on pages 3-4, that:

> "BCSEA-SCBC simply note that using the community definition means that the putative cross-subsidization is between (a) all of the residential electricity customers in the communities without natural gas, including customers who have electric heat and those who use other heating fuels, and (b) residential electricity customers in all other areas of the utility's service territory, including those who use electric heat, those who use natural gas for heating, and those who use other heating fuels. <u>This is very different than</u> an analysis in which "without access to natural gas" is defined as not having natural gas heating (space or water) in the premises for whatever reason. [footnote omitted] In the latter case, the cross-subsidization analysis is between (a) residential electricity customers who <u>don't</u> use natural gas heating (for whatever reason), and (b) residential electricity customers who <u>do</u> use natural gas heating. Unfortunately, it is not entirely clear which definition of "without access to natural gas" the Minister had in mind." [underline added]

1.15.4.2 Is it BC Hydro's view that the Minister's request contemplates a community approach to the definition of "without access to natural gas"?

RESPONSE:

The Commission RIB Report Methodology Letter asked for BC Hydro to provide input into the methodologies to be used to gather information and report on the five questions posed in the Minister RIB Report Letter, including defining the phrase "customers without access to natural gas". In BC Hydro's view, there is no inconsistency between the Minister RIB Report Letter and BC Hydro's proposed community approach to this definition.

16.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.6, BC Hydro Residential Demand Side Management Programs

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states on page 6 that:

> "In BCSEA-SCBC's view, question 4 is not adequately answered by merely describing existing DSM programs (which is what might be inferred from the utilities' responses). BCSEA-SCBC recommend that the Commission clarify that the core of question 4 is what is the potential for existing DSM programs to reduce electricity usage and hence customer bills. For example, what is the potential for an existing DSM program to be ramped up, say with higher incentives, in order to achieve increased energy savings?"

1.16.1 Will BC Hydro include in its report to the Commission on the Minister's question an examination of the potential for existing DSM programs to reduce electricity usage and hence customer bills?

RESPONSE:

In BC Hydro's view "an examination of the potential for existing DSM programs to reduce electricity usage and hence customer bills" goes beyond the Minister RIB Report Letter Questions 4 and 5. Responses to Questions 4 and 5 must be tailored to two Residential customer segments - low income customers and customers without access to natural gas.

In addition, in BC Hydro's view, and as set out in BC Hydro's response to BCUC IR 1.51.1, the Minister RIB Report Letter Questions 1 to 5 call for a two-phased review of BC Hydro's RIB rate. This is clear from Question 4, which asks: "What is the potential for existing [DSM] programs to mitigate these *impacts*" [emphasis added]:

- **First, is there evidence that the RIB rate has bill impacts of over 10 per cent on low income customers and customers without access to natural gas?;**
- **Second, and only if the answer to the first question is yes for one or both of the two Residential customer segments, would BC Hydro report on the potential for additional Residential DSM programs, or potential modifications to existing programs, that could be undertaken within the existing regulatory environment for one or both of these Residential customer segments.**

The critical qualifier to the Question 4 and Question 5 examination is "within the existing regulatory environment". As noted by BC Hydro at pages 5-72 to 5-73 of Exhibit B-1, the phrase "within the existing regulatory environment" must take into account the F2017-F2019 rate caps set out in section 9 of Direction No. 7, and also the fact that the venue for any assessment of DSM program-related expenditures is a section 44.2 *UCA* DSM expenditure schedule determination filing. BC Hydro will be submitting a DSM expenditure schedule determination filing contemporaneously with or as part of the F2017 RRA filing in February 2016, and this filing must be considered as part of Questions 4 and Questions 5.

16.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.6, BC Hydro Residential Demand Side Management Programs

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states on page 6 that:

> "In BCSEA-SCBC's view, question 4 is not adequately answered by merely describing existing DSM programs (which is what might be inferred from the utilities' responses). BCSEA-SCBC recommend that the Commission clarify that the core of question 4 is what is the potential for existing DSM programs to reduce electricity usage and hence customer bills. For example, what is the potential for an existing DSM program to be ramped up, say with higher incentives, in order to achieve increased energy savings?"

1.16.1.1 For example, will BC Hydro address the potential for an existing DSM program to be ramped up, say with higher incentives, in order to achieve increased energy savings?

RESPONSE:

In BC Hydro's view "address[ing] the potential for … existing DSM program[s] to be ramped up, say with higher incentives … to achieve increased energy savings" goes beyond the Minister RIB Report Letter Questions 4 and 5. Please refer to BC Hydro's response to BCSEA IR 1.16.1.

16.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.6, BC Hydro Residential Demand Side Management Programs

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states on page 6 that:

> "In BCSEA-SCBC's view, question 4 is not adequately answered by merely describing existing DSM programs (which is what might be inferred from the utilities' responses). BCSEA-SCBC recommend that the Commission clarify that the core of question 4 is what is the potential for existing DSM programs to reduce electricity usage and hence customer bills. For example, what is the potential for an existing DSM program to be ramped up, say with higher incentives, in order to achieve increased energy savings?"

1.16.2 Does BC Hydro agree that the Minister's Question 5 question 5 is not limited to customers without access to natural gas and asks for the Commission to report on options on additional DSM programs for residential customers generally and for low income residential customers, both within the context of the current regulatory environment? If not, why not?

RESPONSE:

No, BC Hydro does not agree that Minister RIB Report Letter Questions 4 and 5 ask the Commission "to report on options on additional DSM programs for residential customers generally". Responses to Questions 4 and 5 must be tailored to two Residential customer segments - low income customers and customers without access to natural gas. Please refer to BC Hydro's response to BCSEA IR 1.16.1.

16.0 Topic: RIB Rate Report Proceeding

Reference: Exhibit B-1, section 5.6, BC Hydro Residential Demand Side Management Programs

In the Commission's RIB Rate Report proceeding, BCSEA-SCBC's Submission dated October 16, 2015, states on page 6 that:

> "In BCSEA-SCBC's view, question 4 is not adequately answered by merely describing existing DSM programs (which is what might be inferred from the utilities' responses). BCSEA-SCBC recommend that the Commission clarify that the core of question 4 is what is the potential for existing DSM programs to reduce electricity usage and hence customer bills. For example, what is the potential for an existing DSM program to be ramped up, say with higher incentives, in order to achieve increased energy savings?"

1.16.3 Further to BC Hydro's statements on pages 5-72 and 5-73 regarding "the current regulatory environment" referred to in the Minister's Question 5, does BC Hydro agree that the DSM Regulation and sections 44.1 and 44.2 of the Act are the main factors? Please describe BC Hydro's understanding of "the current regulatory environment" referred to in the Minister's Question 5.

RESPONSE:

In BC Hydro's view, the following are the main factors with regard to "the current regulatory environment" as referenced in Minister RIB Report Letter Question 5:

- **The F2017-F2019 rate caps set out in section 9 of Direction No. 7, together with BC Hydro's DSM expenditure schedule determination filing to be made contemporaneously with or as part of the F2017 RRA filing in February 2016; and**

- **BC Hydro also submits that the rate caps and the DSM expenditure schedule filing must be considered as part of Questions 4 and 5. Refer to BC Hydro's response to BCSEA IR 1.16.1.**

Section 44.1 of the *UCA* is not a main factor as this section is not applicable to BC Hydro as a result of subsection 32(7)(x) of the *Hydro and Power Authority Act*.

In BC Hydro's view, the DSM Regulation and in particular section 4 (Cost Effectiveness) is applicable to BC Hydro's DSM expenditure schedule filings made pursuant to subsection 44.2(1)(a) of the *UCA*, but may be relevant to Minister RIB Report Letter Questions 4 and 5.

17.0 Topic: Small General Service Basic Charge

Reference: Exhibit B-1, section 6.2.3.2 SGS Basic Charge Cost Recovery

1.17.1 BC Hydro proposes raising the SGS Basic Charge from about 33% cost recovery to about 45% cost recovery. Please quantify the impact of this change on conservation. Please specify the elasticity assumptions used in the response.

RESPONSE:

With respect to natural conservation, BC Hydro would anticipate the change in conservation to be negligible given the small change in the SGS energy rate as a result of the change in the basic charge cost recovery.

18.0 Topic: Medium General Service, Large General Service, Conservation

Reference: Exhibit B-1, section 6.3 Medium General Service; section 6.4 Large General Service

BC Hydro proposes to change the existing two-part energy rates and three step demand rates for MGS and LGS to flat energy rate .

1.18.1 Further to BC Hydro's response to BCUC IR 1.56.1.1, does BC Hydro consider that the improved customer understanding associated with a flat rate would contribute to increased natural conservation? If so, can this be quantified?

RESPONSE:

BC Hydro is forecasting natural conservation from the proposed MGS rate structure using an elasticity of -0.05, which as noted at Exhibit B-1, page 5-17, lines 12 to 14, is the class average price elasticity assumption used to determine the natural conservation baseline. BC Hydro has no evidence as to whether its proposed LGS and MGS flat energy rates would contribute to increased natural conservation.

Please refer to BC Hydro's response to BCUC IR 1.58.1.

18.0 Topic: Medium General Service, Large General Service, Conservation

Reference: Exhibit B-1, section 6.3 Medium General Service; section 6.4 Large General Service

BC Hydro proposes to change the existing two-part energy rates and three step demand rates for MGS and LGS to flat energy rate .

1.18.2 Does BC Hydro have, or will it develop, a communications strategy for the change to flat MGS and LGS rates designed to foster increased conservation? What elements will be included?

RESPONSE:

As noted in section 1.1.3 of Exhibit B-1, BC Hydro is seeking final order effective April 1, 2017 with respect to the MGS and LGS rates. Among other things, this effective date was chosen to allow for the development and implementation of a communication strategy, as BC Hydro anticipates a Commission decision on RDA Module 1 by fall 2016.

Conceptually, a communications strategy would include notifications to inform customers about the LGS and MGS rate changes, as well as information about how customers can do energy budgeting and estimate bill savings from energy efficiency projects. Communications activities would likely include:

- **A letter to each MGS and LGS customer to inform them of the change;**
- **Messaging on BC Hydro owned channels, such as emails, bchydro.com, bill inserts and bill messages;**
- **Key account customer visits;**
- **DSM program marketing materials;**
- **Awareness messaging through BC Hydro's business account services team; and**
- **Workshops or messaging delivered through industry associations.**

18.0 Topic: Medium General Service, Large General Service, Conservation

Reference: Exhibit B-1, section 6.3 Medium General Service; section 6.4 Large General Service

BC Hydro proposes to change the existing two-part energy rates and three step demand rates for MGS and LGS to flat energy rate .

1.18.3 Will BC Hydro develop new, or package existing, DSM measures for MGS and LGS customers aimed at maximizing the opportunity for the change to flat rates to be associated with increased conservation? If so, please describe. If not, why not?

RESPONSE:

BC Hydro currently provides a range of DSM programs that are available to LGS and MGS customers. These programs include activities that are designed to help customers achieve energy savings related to behavioural and operational changes and capital projects. For example, BC Hydro's Continuous Optimization offer is designed to help commercial building owners re-commission their building and to help maintain and continually improve the level of efficiency, which results in reduced operating costs.

BC Hydro will be filing a section 44.2 *UCA* DSM expenditure schedule determination request with the Commission contemporaneously with or as part of the F2017 RRA in February 2016.

18.0 Topic: Medium General Service, Large General Service, Conservation

Reference: Exhibit B-1, section 6.3 Medium General Service; section 6.4 Large General Service

BC Hydro proposes to change the existing two-part energy rates and three step demand rates for MGS and LGS to flat energy rate .

1.18.4 Will BC Hydro identify MGS and LGS customers who have or would have had conservation opportunities under the existing rate structures that would be lost or impeded by a change to a flat rate? Will BC Hydro work with such customers to find ways to implement these conservation opportunities under a flat rate scenario?

RESPONSE:

Please refer to BC Hydro's response to BCSEA IRs 1.18.2 and 1.18.3.

18.0 Topic: Medium General Service, Large General Service, Conservation

Reference: Exhibit B-1, section 6.3 Medium General Service; section 6.4 Large General Service

BC Hydro proposes to change the existing two-part energy rates and three step demand rates for MGS and LGS to flat energy rate .

1.18.5 BC Hydro proposes that the new MGS and LGS rate designs (flat energy and flat demand) would come into effect as of April 1, 2017. Does BC Hydro agree that one advantage of this effective date is that it gives BC Hydro roughly one year from the Commission's decision on the Application within which to develop and implement a strategy for maximizing the potential conservation opportunities inherent in the change to flat energy and demand rates?

RESPONSE:

The main advantage associated with an effective date of April 1, 2017 is to enable BC Hydro to implement billing changes and a communication strategy. With respect to DSM programs, please refer to BC Hydro's response to BCSEA IR 1.18.3.

19.0 Topic: **LGS and MGS New Account Rule**

Reference: **Exhibit B-1, section 6.6, Requested Order for the LGS and MGS New Account Rule, p. 6-71**

1.19.1 Would the proposed "100 per cent Part 1 Pricing" for New Accounts cause a cross-subsidy? If so, how large? If not, why not?

RESPONSE:

No, "100 per cent Part 1 Pricing" for New Accounts would not cause a cross-subsidy between the LGS and MGS classes with other rate classes. In setting the rates, Part 1 Pricing is largely based on BC Hydro's embedded costs for the MGS and LGS rate classes with minor adjustments for forecasted Part 2 charges and credits.

19.0 Topic: LGS and MGS New Account Rule

Reference: Exhibit B-1, section 6.6, Requested Order for the LGS and MGS New Account Rule, p. 6-71

1.19.2 Would it be feasible for the New Account rate to be set on an interim and refundable basis at a rate that BC Hydro estimates would be equivalent to the proposed flat rates for LGS and MGS customers?

RESPONSE:

BC Hydro's proposes that LGS and MGS flat rates be implemented at the same time for all accounts effective April 1, 2017. This would be simpler to implement than having new accounts pay the new flat rate in advance of other customers which would require a separate rate schedule and which would cause additional billing costs.

19.0 Topic: **LGS and MGS New Account Rule**

Reference: **Exhibit B-1, section 6.6, Requested Order for the LGS and MGS New Account Rule, p. 6-71**

1.19.3 Please confirm, or otherwise explain, that the proposed "100 per cent Part 1 Pricing" for LGS and MGS New Accounts would expire when the proposed flat rates for LGS and MGS come into effect.

RESPONSE:

Confirmed.

19.0 Topic: **LGS and MGS New Account Rule**

Reference: **Exhibit B-1, section 6.6, Requested Order for the LGS and MGS New Account Rule, p. 6-71**

1.19.4 Is it BC Hydro's intention that proposed "100 per cent Part 1 Pricing" for LGS and MGS New Accounts would remain in place indefinitely if the Commission does not approve the flattening of the LGS and MGS rates?

RESPONSE:

BC Hydro's intention is that the 100 per cent Part 1 Pricing would remain in place if the Commission does not approve BC Hydro's proposal to flatten the LGS and MGS rates.

20.0 Topic: Nomenclature

Reference: Exhibit B-1, Appendix B, Glossary and Abbreviations

1.20.1 Please provide a table showing for each of BC Hydro's rate schedules and tariff supplements, existing and proposed, the identification number (e.g., RS 1853), the common name (e.g., IPP Station Service), and a very brief description. The intention is to have a searchable reference for use in this proceeding. Obsolete rates could be omitted. Please also include informal terms such as RS 15xx. If BC Hydro already has a list of rate schedules and tariff supplements then please provide a copy of it instead of the requested table.

RESPONSE:

A listing of Rate Schedules is provided in the table below.

A table of Tariff Supplements has not been provided as BC Hydro will be reviewing Tariff Supplements as part of its responses to Round 2 IRs to determine which are still in effect for inclusion in any listing.

Residential Service

Rate Schedule	Rate Schedule Name	Description
1101[1]	**Residential Service**	**Default Residential Service rate for Customers in Rate Zone I**
1121	**Residential Service**	**Multiple Residential Service rate for Customers in Rate Zone I where the Premises contains more than two Dwellings**
1105	**Residential Service - Dual Fuel (Closed)**	**Also referred to as the "E-Plus" rate** **Closed Residential Service rate for space and water heating on an interruptible basis in Rate Zone I**
1107[2]	**Residential Service – Zone II**	**Default Residential Service rate for Customers in Rate Zone II**
1127	**Residential Service – Zone II**	**Multiple Residential Service rate for Customers in Rate Zone II where the Premises contains more than two Dwellings**
1148	**Residential Service – Zone II (Closed)**	**Closed Residential Service rate for Customers in Rate Zone II where a permanent electric space heating system installed prior to October 10, 1966 is in use**

Rate Schedule	Rate Schedule Name	Description
1151[3]	**Exempt Residential Service**	**Residential Service rate for uses exempted from Rate Schedule 1101, including on farms in Rate Zone I** **Default Residential Service rate for Customers in Rate Zone IB**
1161	**Exempt Multiple Residential Service**	**Multiple Residential Service rate for uses exempted from Rate Schedule 1121, including on farms in Rate Zone I** **Default Multiple Residential Service rate for Customers in Rate Zone IB**

General Service

Rate Schedule	Rate Schedule Name	Description
1200[3] **1201** **1210** **1211**	**Exempt General Service Rate (35 kW and Over)**	**Also referred to as "12XX" rates** **Default General Service rate for Customers in Rate Zone IB with Billing Demand of 35 kW or more** **General Service rate for Customers enrolled in the Medium or Large General Service control groups** **1200 – Service is metered at Secondary Voltage and BC Hydro supplies Transformation** **1201 – Service is metered at Primary Voltage and BC Hydro supplies Transformation (1.5% discount applies)** **1210 – Service is metered at Secondary Voltage and Customer supplies Transformation (25¢/kW discount applies)** **1211 – Service is metered at Primary Voltage and Ccustomer supplies Transformation (1.5% and 25¢/kW discounts apply)**
1205 **1206** **1207**	**General Service - Dual Fuel (Closed)**	**Also referred to as "E-Plus" rates** **Closed General Service rate for space heating, water heating and industrial process heating on an interruptible basis in Rate Zone I** **1205 – Small Commercial Applications (under 35 kW)** **1206 – Large Commercial Applications (35 kW and over)** **1207 – Industrial Applications**
1234[2]	**Small General Service (Under 35 kW) – Zone II**	**Default General Service rate for Customers in Rate Zone II with estimated Demand of less than 35 kW**
1253	**Distribution Service – IPP Station Service**	**Distribution Service rate for Independent Power Producers in Rate Zone I (excluding Kingsgate-Yahk and Lardeau-Shutty Bench) for maintenance and black-start purposes, on an interruptible basis**

Rate Schedule	Rate Schedule Name	Description
1255[2] **1256** **1265** **1266**	**General Service Rate (35 kW and over) – Zone II**	**Default General Service rate for Customers in Rate Zone II with Demand of 35 kW or more** **1255 – Service is metered at Secondary Voltage and BC Hydro supplies Transformation** **1256 – Service is metered at Primary Voltage and BC Hydro supplies Transformation (1.5% discount applies)** **1265 – Service is metered at Secondary Voltage and Customer supplies Transformation (25¢/kW discount applies)** **1266 – Service is metered at Primary Voltage and Customer supplies Transformation (1.5% and 25¢/kW discounts apply)**
1268	**Distribution Service – IPP Distribution Transportation Access**	**Distribution Service rate for Customers in Rate Zone I (excluding Kingsgate-Yahk and Lardeau-Shutty Bench) with generators connected to BC Hydro's distribution system and want access to BC Hydro's transmission system**
1278	**Power Service (Closed)**	**Closed Power Service rate for use in electric steel making and the electric heating or melting of metals or other materials when part of a continuous production process** **Available for Customers served under this Rate Schedule on April 1, 1970 and continuously thereafter in those parts of the Lower Mainland serviced by B.C. Electric Company Ltd. on March 29, 1962**
1280	**Shore Power Service (Distribution)**	**General Service rate for Port Customers in Rate Zone I for use by Eligible Vessels while docked at the Port Customer's Port Facility, on an interruptible basis**
1300[4] **1301** **1310** **1311**	**Small General Service (Under 35 kW)**	**Also referred to as "13XX" rates** **Default General Service rate for Customers in Rate Zones I and IB with Demand of less than 35 kW** **1300 – Service is metered at Secondary Voltage and BC Hydro supplies Transformation** **1301 – Service is metered at Primary Voltage and BC Hydro supplies Transformation (1.5% discount applies)** **1310 – Service is metered at Secondary Voltage and Customer supplies Transformation (25¢/kW discount applies)** **1311 – Service is metered at Primary Voltage and Customer supplies Transformation (1.5% and 25¢/kW discounts apply)**

Rate Schedule	Rate Schedule Name	Description
1500[1] **1501** **1510** **1511**	**Medium General Service (35 kW or greater and less than 150 kW)**	**Also referred to as "15XX" rates** **Default General Service rate for Customers in Rate Zone I with Billing Demand of between 35 kW and 150 kW, or whose Energy consumption in a 12-month period is equal to or less than 550,000 kW.h** **1500 – Service is metered at Secondary Voltage and BC Hydro supplies Transformation** **1501 – Service is metered at Primary Voltage and BC Hydro supplies Transformation (1.5% discount applies)** **1510 – Service is metered at Secondary Voltage and Customer supplies Transformation (25¢/kW discount applies)** **1511 – Service is metered at Primary Voltage and Customer supplies Transformation (1.5% and 25¢/kW discounts apply)**
1600[1] **1601** **1610** **1611**	**Large General Service (150 kW and over)**	**Also referred to as "16XX" rates** **Default General Service rate for Customers in Rate Zone I with Billing Demand of 150kW or more, or whose Energy consumption in a 12-month period is greater than 550,000 kW.h** **1600 – Service is metered at Secondary Voltage and BC Hydro supplies Transformation** **1601 – Service is metered at Primary Voltage and BC Hydro supplies Transformation (1.5% discount applies)** **1610 – Service is metered at Secondary Voltage and Customer supplies Transformation (25¢/kW discount applies)** **1611 – Service is metered at Primary Voltage and Customer supplies transformation (1.5% and 25¢/kW discounts apply)**

Rate Schedule	Rate Schedule Name	Description
2600 **2601** **2010** **2611**	**Large General Service (150 kW and over) for Distribution Utilities**	**General Service rate for public utility Customers in Rate Zone I who are regulated by the B.C. Utilities Commission and that elect Service under these Rate Schedules for resale purposes** **2600 – Service is metered at Secondary Voltage and BC Hydro supplies Transformation** **2601 – Service is metered at Primary Voltage and BC Hydro supplies Transformation (1.5% discount applies)** **2610 – Service is metered at Secondary Voltage and Customer supplies Transformation (25¢/kW discount applies)** **2611 – Service is metered at Primary Voltage and Customer supplies transformation (1.5% and 25¢/kW discounts apply)**

Irrigation

Rate Schedule	Rate Schedule Name	Description
1401[4]	**Irrigation Service**	**Irrigation Service rate for Customers in Rate Zones I and IB for motor loads of 746 watts or more used for irrigation and outdoor sprinkling**

Street Lighting

Rate Schedule	Rate Schedule Name	Description
1701	**Overhead Street Lighting**	**Street Lighting Service rate for Customers in any area served by suitable overhead distribution lines for lighting of public highways, streets and lanes where BC Hydro owns, installs and maintains the fixtures, conductors, controls and poles**
1702	**Public Area Ornamental Street Lighting**	**Street Lighting Service rate for Customers in all Rate Zones for lighting of public highways, streets and lanes and municipal pathways and for public area seasonal lighting displays where the Customer owns, installs and maintains the standards, fixtures, conductors and controls**

Rate Schedule	Rate Schedule Name	Description
1703	**Street Lighting Service**	**Street Lighting Service rate for Customers in Victoria, Prince Rupert, Oak Bay, Esquimalt, Saanich and Central Saanich, Sidney, Port Renfrew, Shawnigan Lake, a portion of New Wesminster, Natal and Vancouver for lighting of public highways, streets and lanes where the Customer owns, installs and maintains the fixtures, conductors and controls on BC Hydro poles**
1704	**Traffic Control Equipment**	**Street Lighting Service rate for Customers in all Rate Zones for traffic signals, traffic signs and traffic warning devices and other equipment for vehicular or pedestrian traffic on public highways where the Customer owns and maintains the standards, fixtures, wiring, controls and associated equipment**
1755	**Private Outdoor Lighting (Closed)**	**Closed Street Lighting Service rate for Customers in all Rate Zones to illuminate private property from dusk to dawn**

Transmission Service

Rate Schedule	Rate Schedule Name	Description
1823[5]	**Stepped Rate**	**Default Transmission Service rate for Customers in Rate Zone I (excluding Kingsgate-Yahk and Lardeau-Shutty Bench)**
1825	**Transmission Service – Time-of-Use (TOU) Rate**	**Transmission Service rate for Customers with CBLs who are eligible to take Service under Rate Schedule 1823 and who have entered into a TOU Agreement with BC Hydro**
1827	**Transmission Service - Rate for Exempt Customers**	**Transmission Service rate for Customers in Rate Zone I (excluding Kingsgate-Yahk and Lardeau-Shutty Bench) that are exempted from Service under Rate Schedule 1823 by the British Columbia Utilities Commission, including the City of New Westminster and the University of British Columbia**
1852	**Transmission Service - Modified Demand**	**Transmission Service rate for Customers taking Service under Rate Schedule 1823 who have entered into a Modified Demand Agreement with BC Hydro**
1853	**Transmission Service - IPP Station Service**	**Transmission Service rate for Independent Power Producers in Rate Zone I (excluding Kingsgate-Yahk and Lardeau-Shutty Bench) for maintenance and black-start purposes, on an interruptible basis**
1880	**Transmission Service - Standby and Maintenance Supply**	**Transmission Service rate for Customers served under Rate Schedules 1823, 1825, 1827 or 1852 in Rate Zone I (excluding Kingsgate-Yahk and Lardeau-Shutty Bench), on an interruptible basis**

Rate Schedule	Rate Schedule Name	Description
1891	**Transmission Service – Shore Power Service**	**Transmission Service rate for Port Customers in Rate Zone I for use by Eligible Vessels while docked at the Port Customer's Port Facility, on an interruptible basis**
1892[6]	**Transmission Service – Freshet Energy**	**Transmission Service rate for Customers served under Rate Schedule 1823 in Rate Zone I (excluding Kingsgate-Yahk and Lardeau-Shutty Bench) who increase their Electricity usage during the Freshet Period, on an interruptible basis** **This Rate Schedule terminates December 31, 2017**
3808	**Transmission Service – FortisBC Inc.**	**Rate for Transmission Service in accordance with the Power Purchase Agreement between FortisBC Inc. and BC Hydro**
3817	**Wheeling Service – FortisBC Inc.**	**Rate for the wheeling of electricity over BC Hydro's transmission facilities in accordance with the Amended and Restated Wheeling Agreement between FortisBC Inc. and BC Hydro**

Other

Rate Schedule	Rate Schedule Name	Description
1289	**Net Metering Service**	**Rate for Residential Service and General Service Customers in all Rate Zones who install Generating Facilities to serve all or part of their electricity requirements**
1901	**Deferral Account Rate Rider**	**Rate rider that applies to all charges payable under other Rate Schedules and Electric Tariff Supplements 7, 8, 39 and 77**

[1] Default rate for rate class (Rate Zone I).

[2] Default rate for rate class (Rate Zone II).

[3] Default rate for rate class (Rate Zone IB).

[4] Default rate for rate class (Rate Zone I and IB).

[5] Default rate for rate class (Rate Zone I excluding the Districts of Kingsgate-Yahk and Lardeau-Shutty Bench.

[6] New rate proposed in the 2015 RDA.

REQUESTOR NAME: **Clean Energy Association of B.C. (CEBC)**

INFORMATION REQUEST ROUND NO: **1**

TO: **BRITISH COLUMBIA HYDRO & POWER AUTHORITY**

DATE: November 17, 2015

PROJECT NO:

APPLICATION NAME: **2015 Rate Design Application (2015 RDA)**

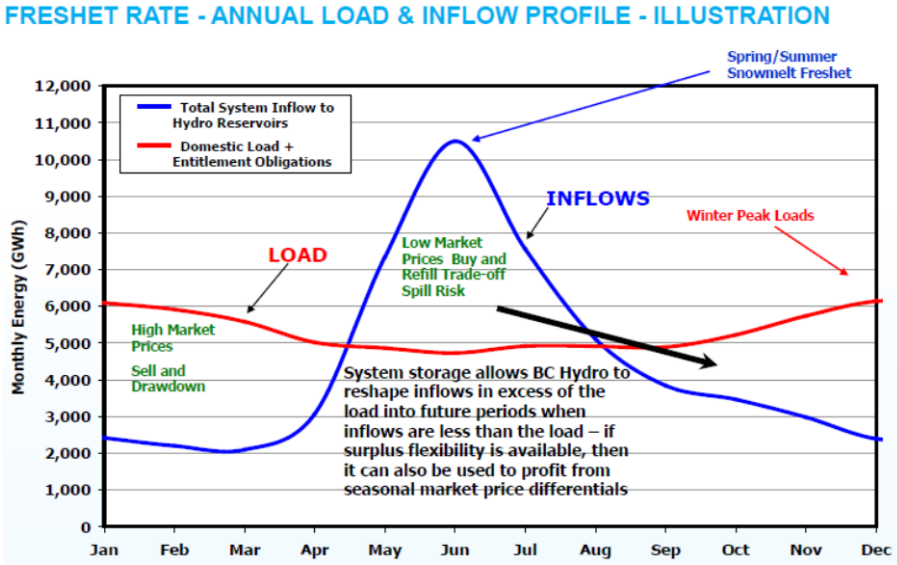
1.0 Reference: Exhibit B-1, Application, Section 7.3.4 Proposed Freshet Rate Pilot

On pages 7-27 to 7-28, BC Hydro outlines its objectives for the proposed freshet rate, including the following:

> *"...2. Assist in the management of the freshet oversupply in the BC Hydro system by providing the option to:*
>
> - *Increase the ability to import cheap electricity during low priced periods;*
> - *Reduce the volume of surplus energy being forced to export markets; and/or*
> - *Reduce spill at BC Hydro facilities;*

It further asserts that, *"the freshet rate would encourage customers to increase electricity consumption during the freshet period (May-July), when BC Hydro has a long-term recurring issue of energy oversupply."*

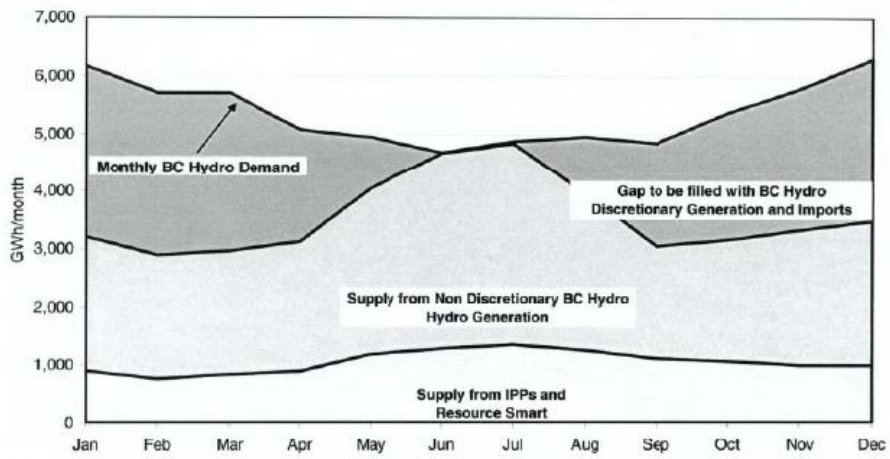
As an illustration of the problem, BC Hydro provided Figure 7-2, showing system inflows vs. monthly load. The following similar figure appeared at slide 29 of the Workshop #5 presentation material:



However, as the large note indicates, system inflows do not well define the problem because system storage is generally managed to reshape those flows.

In CEBC's view, BC Hydro has provided more useful information in the past by showing the load vs. discretionary and non-discretionary generation. An example of this is taken from the 2006 IEP/LTAP Hearing (Attachment to the response to IPPBC IR 1.15.2), a portion of which is shown below.

Figure 8: Wet Year BC Hydro Supply and Demand - Seasonal Profile for 2012



And, to accompany this and similar charts, BC Hydro included the information in tabular form:

Table 3: Chart Data for 2012

Average Year (GWh/Month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	835	885	1,184	1,282	1,358	1,259	1,107	1,065	992	988
Supply from Non Discretionary BC Hydro Generation	2,112	1,916	1,980	2,086	2,768	2,953	2,545	1,940	1,765	2,017	2,086	2,149
Gap to be filled with BC Hydro Discretionary Generation and Imports	3,166	3,043	2,897	2,104	994	443	968	1,755	1,975	2,296	2,715	3,172
Monthly BC Hydro Demand	6,172	5,713	5,711	5,074	4,946	4,678	4,870	4,954	4,848	5,378	5,793	6,310

Data for Area Charts Wet Year (GWh/Month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	835	885	1,184	1,282	1,358	1,259	1,107	1,065	992	988
Supply from Non Discretionary BC Hydro Generation	2,312	2,142	2,134	2,243	2,864	3,377	3,484	2,701	1,948	2,099	2,336	2,491
Gap to be filled with BC Hydro Discretionary Generation and Imports	2,967	2,818	2,743	1,946	898	19	30	994	1,792	2,213	2,465	2,830
Monthly BC Hydro Demand	6,172	5,713	5,711	5,074	4,946	4,678	4,870	4,954	4,848	5,378	5,793	6,310

Data for Area Charts Dry Year (GWh/Month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	835	885	1,184	1,282	1,358	1,259	1,107	1,065	992	988
Supply from Non Discretionary BC Hydro Generation	1,654	1,392	1,298	1,353	2,425	2,404	2,047	1,744	1,434	1,807	1,830	1,950
Gap to be filled with BC Hydro Discretionary Generation and Imports	3,625	3,567	3,578	2,837	1,337	992	1,466	1,951	2,306	2,506	2,971	3,372
Monthly BC Hydro Demand	6,172	5,713	5,711	5,074	4,946	4,678	4,870	4,954	4,848	5,378	5,793	6,310

CEBC found this format to be much more illustrative of the extent of the oversupply problem and, in the following information requests, seeks to use a similar format to:

1. clarify the recent and current extent of this "long-term recurring issue of energy oversupply,"
2. understand how known future events are expected to impact on this oversupply, and
3. explore various possible ways in which this oversupply situation could be mitigated, possibly with greater benefits to ratepayers than a freshet rate might bring.

1.1 To facilitate a clearer understanding of the recent and current status of the oversupply problem, please provide the historical monthly information in a tabular and chart format similar to the table and chart above, for the actual results in the years 2012 through 2015 (to the extent that 2015 is available). In the tables and charts, please include the following as separate line items:

- Supply from IPPs
- Supply from BCH Resource Smart
- Supply from non-discretionary BCH hydro generation
- Supply from imports
- Supply from BCH discretionary generation
- SUBTOTAL - Total energy available to serve domestic load
- Minus energy exported
- TOTAL - Monthly energy used to serve BCH domestic load

1.2 To give a better understanding of the future status of the oversupply problem, please provide the same tabular and chart information projected for the years 2016 and 2017 (the subject years for

the pilot rate), assuming dry, average, and wet water years and prior to any impact of the pilot freshet rate implementation.

1.3 To give a better understanding of the impact of climate change on the oversupply problem, please provide the same tabular and chart information projected for the years 2020 and 2025, again assuming dry, average, and wet water years, but including BC Hydro's expectation of how climate change may be altering the system inflows and incorporating how BCH would best manage its storage facilities to accommodate the changes.

1.4 Site C will draw on inflows from several Peace River tributaries. What impact will this have on system inflows during the freshet season? To give a better understanding of the impact of Site C on the oversupply problem, please provide the same tabular and chart information projected for the first full year of operation for Site C.

1.5 BC Hydro has proposed to upgrade its transmission line from Terrace to Kitimat to serve possible LNG loads in Kitimat. Could such an upgrade also allow BC Hydro to serve some of Alcan's smelter load in the freshet season, thus increasing the system storage capacity by utilizing Alcan's Nechako reservoir? Please provide BC Hydro's analysis of the potential of any such a transmission upgrade to lessen the freshet oversupply problem.

1.6 Please provide the full details of the constraints on the transmission line between Terrace and Kitimat that prevents BC Hydro during the May to July freshet period from using to the fullest extent possible the equichange and storage provisions in the 2007 electricity purchase agreement between Alcan and BC Hydro as approved by the British Columbia Utilities Commission on January 29, 2008 ("Alcan Agreement").

1.7 Please provide the full details of BC Hydro's use of the equichange and storage provisions in the Agreement in each year from 2008 to 2015.

1.8 If this transmission line is upgraded or replaced in order to serve Shell's proposed LNG project at Kitimat or another LNG project, please provide the full details of BC Hydro's ability to use to the fullest extent during the freshet period the equichange and storage provisions in the Agreement?

1.9 A single major LNG liquefaction plant (such as the Shell project) could require up to 10,000 GWh/yr if fully electrified, and the associated pipelines and upstream activities could require a similar amount of energy. Accordingly, if BC Hydro were to acquire only 50% of that single project's additional upstream and downstream load, it could amount to an additional 1200 MW of load, on a 24/7 ongoing basis. What impact would this magnitude of additional industrial load have on the projected future freshet oversupply problem?

1.10 BC Hydro has explored the possibility of building pumped storage facilities at many locations around the province, including a 500 MW facility at Mica. Assuming BC Hydro had such a 500 MW facility at Mica, please simulate how it would have operated during the past 4 years, from 2012 to 2015. In each of those years, how much freshet energy could have been purchased and effectively "stored" in the Kinbasket reservoir for sale at a more opportune time? Please also estimate how much of a price increase BC Hydro could have realized by reselling that energy in higher-priced periods during the year.

2.0 Reference: Exhibit B-1, Section 2.2.1.2, page 2-5, Clean Energy Act

2.1 How are the rate classes and rate design in the Application consistent with section 2(h) of the Clean Energy Act which says: "to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas (GHGP emissions in B. C."?

3.0 Reference: Exhibit B-1, Section 2.3.2.2, page 2-50, Energy Long-Run Marginal Cost

3.1 Why is there a price difference between bio-energy EPA renewals which on average are expected to be approximately $95/MWh and run-of-river renewals at approximately $70/MWh ($F2016). Will there be restrictions on delivery or differences in the price paid for bio-energy EPA renewals during the spring freshet?

4.0 Reference: Exhibit B-1, Section 2.4.1, page 2-56, Bonbright Criteria

4.1 Why in an age of rapidly changing technology in the electricity industry such as roof top solar panels and battery storage systems that allow some users of electricity to become self-sufficient in electricity are the Bonbright criteria relevant in rate design?

4.2 Please explain how the business model, used by BCH for the purposes of the Application, factors in competition and rapid technological changes in the market place? How is BCH proposing to retain its customers through its rate class structure and rate design as its rates climb and the cost of electricity customer self-supply declines?

5.0 Reference: Exhibit B-1, Section 7.3.3.1, page 7-24, Retail Access

5.1 Why isn't the freshet pilot program a form of retail access? Why should BCH's customers be allowed to purchase electricity at market based rate while third parties are prohibited from providing electricity to these customers on similar terms and conditions, including price?

1.0 Reference: Exhibit B-1, Application, Section 7.3.4 Proposed Freshet Rate Pilot

On pages 7-27 to 7-28, BC Hydro outlines its objectives for the proposed freshet rate, including the following:

"...2. Assist in the management of the freshet oversupply in the BC Hydro system by providing the option to:

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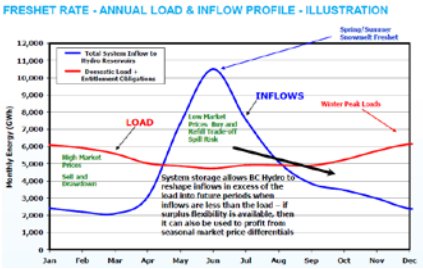

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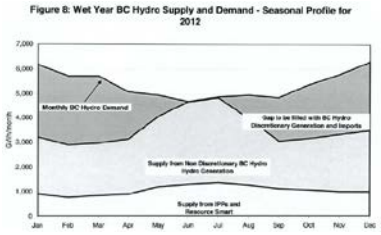

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Data for Area Charts **Wet Year (GWh/Month)**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
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- Supply from BCH discretionary generation
- SUBTOTAL - Total energy available to serve domestic load
- Minus energy exported
- TOTAL - Monthly energy used to serve BCH domestic load

RESPONSE:

Please refer to BC Hydro’s response to BCUC IRs 1.104.1 and 1.105.1. CEBC referenced a long-term planning document, the 2006 IEP/LTAP, to request information that is more appropriately addressed in the IRP as opposed to the assessment of the proposed two-year freshet rate pilot spanning the March 1, 2016 to December 31, 2017 timeframe. Accordingly, the referred to responses do not provide all of the information requested in CEBC IRs 1.1.1 and 1.1.2 for the following reasons:

- **The issue of which particular resources contribute to the freshet oversupply is not relevant to and cannot assist with review of the freshet rate pilot. The freshet oversupply is an overall system issue that BC Hydro is experiencing and wants to address. While freshet**

oversupply is expected to be a long-term recurring issue and the extent of the issue will vary depending on water conditions, hour to hour load-resource balance, market conditions, etc., the freshet rate pilot is proposed for the March 1, 2016 to December 31, 2017 timeframe;

- **BC Hydro reviews its system requirement periodically and modifies its need for resources by considering system constraints that exist at the then current time. The selection/comparison of long-term resource options to meet system needs is done as part of the IRP (a long-term planning exercise). Not withstanding the freshet oversupply issue, resources with freshet energy may still be selected if their overall benefits (including firm energy and dependable capacity contribution) outweigh other alternatives;**

- **In the long-term, large flat load such as LNG and capacity options such as pumped storage would be helpful to further alleviate the freshet oversupply problem. However, the amount of flat load is beyond BC Hydro's control and pumped storage is a capital intense resource with a long lead time. These are considerations beyond the two-year trial period of the freshet rate pilot and are appropriately addressed in a long-term planning exercise such as the IRP.**

1.0 Reference: Exhibit B-1, Application, Section 7.3.4 Proposed Freshet Rate Pilot

On pages 7-27 to 7-28, BC Hydro outlines its objectives for the proposed freshet rate, including the following:

"...2. Assist in the management of the freshet oversupply in the BC Hydro system by providing the option to:

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- Reduce spill at BC Hydro facilities;

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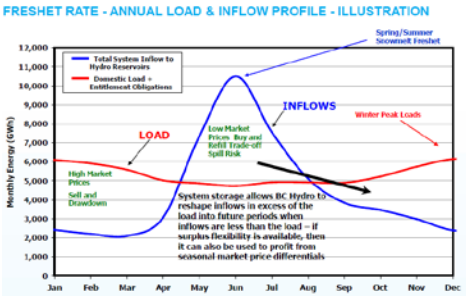

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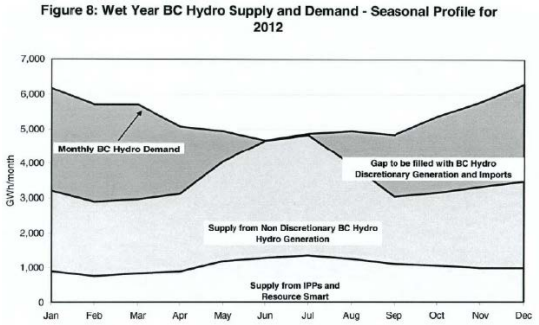

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Table 3: Chart Data for 2012

Average Year (GWh/Month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	835	865	1,184	1,282	1,356	1,259	1,107	1,065	992	988
Supply from Non Discretionary BC Hydro Generation	2,112	1,916	1,960	2,086	2,768	2,953	2,545	1,940	1,765	2,017	2,086	2,149
Gap to be filled with BC Hydro Discretionary Generation and Imports	3,166	3,043	2,897	2,124	994	443	966	1,755	1,975	2,296	2,715	3,172
Monthly BC Hydro Demand	6,172	5,713	5,711	5,074	4,946	4,678	4,870	4,954	4,848	5,378	5,793	6,310

Data for Area Charts **Wet Year (GWh/Month)**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	835	865	1,184	1,282	1,356	1,259	1,107	1,065	992	988
Supply from Non Discretionary BC Hydro Generation	2,312	2,142	2,134	2,243	2,864	3,377	3,484	2,701	1,948	2,009	2,336	2,491
Gap to be filled with BC Hydro Discretionary Generation and Imports	2,967	2,818	2,743	1,966	898	19	30	994	1,792	2,213	2,465	2,830
Monthly BC Hydro Demand	6,172	5,713	5,711	5,074	4,946	4,678	4,870	4,954	4,848	5,378	5,793	6,310

Data for Area Charts **Dry Year (GWh/Month)**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	835	865	1,184	1,282	1,356	1,259	1,107	1,065	992	988
Supply from Non Discretionary BC Hydro Generation	1,654	1,392	1,298	1,363	2,425	2,404	2,047	1,144	1,434	1,807	1,830	1,990
Gap to be filled with BC Hydro Discretionary Generation and Imports	3,625	3,567	3,578	2,847	1,337	992	1,468	1,551	2,306	2,506	2,971	3,372
Monthly BC Hydro Demand	6,172	5,713	5,711	5,074	4,946	4,678	4,870	4,954	4,848	5,378	5,793	6,310

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3. explore various possible ways in which this oversupply situation could be mitigated, possibly with greater benefits to ratepayers than a freshet rate might bring.

1.1.2 To give a better understanding of the future status of the oversupply problem, please provide the same tabular and chart information projected for the years 2016 and 2017 (the subject years for the pilot rate), assuming dry, average, and wet water years and prior to any impact of the pilot freshet rate implementation.

RESPONSE:

Please refer to BC Hydro’s response to CEBC IR 1.1.1.

1.0 Reference: Exhibit B-1, Application, Section 7.3.4 Proposed Freshet Rate Pilot

On pages 7-27 to 7-28, BC Hydro outlines its objectives for the proposed freshet rate, including the following:

"...2. Assist in the management of the freshet oversupply in the BC Hydro system by providing the option to:

- Increase the ability to import cheap electricity during low priced periods;
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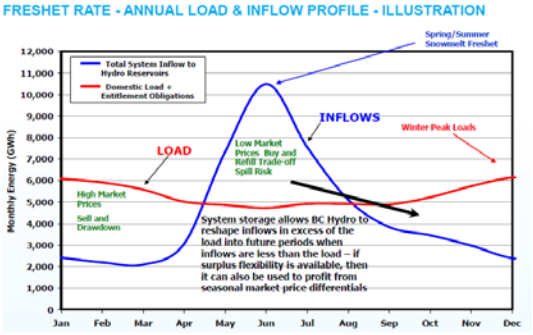

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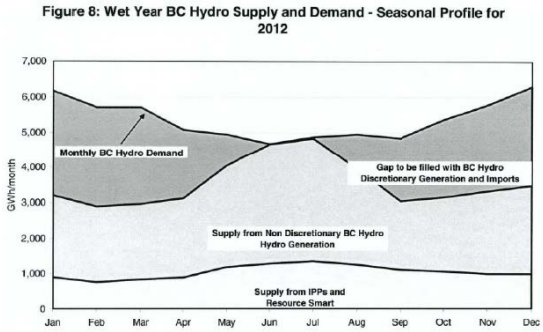

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Table 3: Chart Data for 2012

Average Year (GWh/Month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	835	885	1,184	1,282	1,356	1,259	1,107	1,065	992	988
Supply from Non Discretionary BC Hydro Generation	2,112	1,916	1,960	2,086	2,768	2,953	2,545	1,940	1,765	2,017	2,086	2,149
Gap to be filled with BC Hydro Discretionary Generation and Imports	3,166	3,043	2,897	2,104	994	443	968	1,755	1,976	2,296	2,715	3,172
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Data for Area Charts **Wet Year (GWh/Month)**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	835	885	1,184	1,282	1,356	1,259	1,107	1,065	992	988
Supply from Non Discretionary BC Hydro Generation	2,312	2,142	2,134	2,243	2,864	3,377	3,484	2,701	1,948	2,089	2,336	2,491
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Monthly BC Hydro Demand	6,172	5,713	5,711	5,074	4,946	4,678	4,870	4,954	4,848	5,378	5,793	6,310

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Supply from IPPs + Resource Smart	894	754	835	885	1,184	1,282	1,356	1,259	1,107	1,065	992	988
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1.1.3 To give a better understanding of the impact of climate change on the oversupply problem, please provide the same tabular and chart information projected for the years 2020 and 2025, again assuming dry, average, and wet water years, but including BC Hydro’s expectation of how climate change may be altering the system inflows and incorporating how BCH would best manage its storage facilities to accommodate the changes.

RESPONSE:

In BC Hydro’s respectful submission, the requested information is not relevant because it cannot aid in the review of the 2015 RDA or the orders sought with respect to it. The freshet rate pilot proposal is for the period March 1, 2016 to December 31, 2017 (Exhibit B-1, page 1-12, lines 12 to 13), and this IR asks for information concerning the years 2020 to 2025.

Nevertheless, to be responsive, BC Hydro provides the following information. As shown in Table 5 of Appendix 2C of the 2013 IRP, analyses of historical trends in reservoir inflows do not show any statistically significant changes in the freshet volume. Climate change projections for the period 2041 to 2070 (which is much beyond the 2020 to 2025 timeframe) suggest increases in the freshet volume for the Peace and Columbia systems, and a substantial decrease in the freshet volume for coastal reservoirs.

1.0 Reference: Exhibit B-1, Application, Section 7.3.4 Proposed Freshet Rate Pilot

On pages 7-27 to 7-28, BC Hydro outlines its objectives for the proposed freshet rate, including the following:

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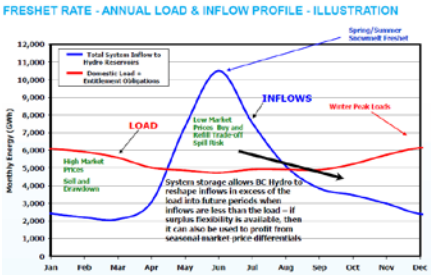

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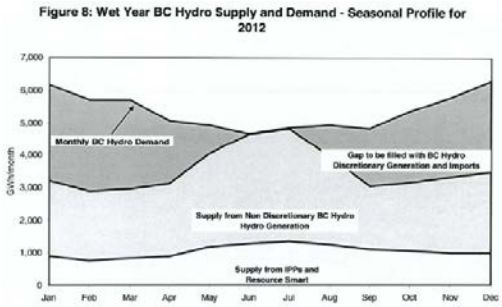

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Data for Area Charts

Wet Year (GWh/Month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
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1.1.4 Site C will draw on inflows from several Peace River tributaries. What impact will this have on system inflows during the freshet season? To give a better understanding of the impact of Site C on the oversupply problem, please provide the same tabular and chart information projected for the first full year of operation for Site C.

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the requested information cannot aid in the review of the 2015 RDA or the orders sought with respect to it:

- **BC Hydro notes that its freshet rate pilot proposal is for the period March 1, 2016 to December 31, 2017; and**

- **BC Hydro expects to have two of the six Site C generating units commissioned and in-service at the end of F2024, with the remaining units coming into service in F2025, well beyond the two-year period of the proposed freshet rate pilot.**

1.0 Reference: Exhibit B-1, Application, Section 7.3.4 Proposed Freshet Rate Pilot

On pages 7-27 to 7-28, BC Hydro outlines its objectives for the proposed freshet rate, including the following:

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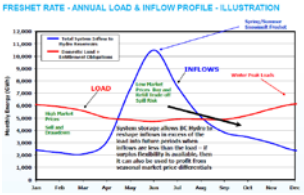

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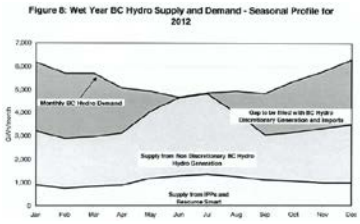

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1.1.5 BC Hydro has proposed to upgrade its transmission line from Terrace to Kitimat to serve possible LNG loads in Kitimat. Could such an upgrade also allow BC Hydro to serve some of Alcan’s smelter load in the freshet season, thus increasing the system storage capacity by utilizing Alcan’s Nechako reservoir? Please provide BC Hydro’s analysis of the potential of any such a transmission upgrade to lessen the freshet oversupply problem.

RESPONSE:

BC Hydro respectively submits that the issue of the Transmission line upgrade referenced in CEBC IR 1.1.5 is not relevant to and cannot assist with the review of the freshet rate pilot because the ISD of the transmission line is about F2020 and accordingly will be in service beyond the two-year timeframe of the proposed pilot. In any event, any upgrade to transmission that would result in offloading Kemano generation, thereby increasing storage in Nechako reservoir, would constrain the operation of the reservoir. Please refer to BC Hydro’s response to CEBC IR 1.1.6.

1.0 Reference: Exhibit B-1, Application, Section 7.3.4 Proposed Freshet Rate Pilot

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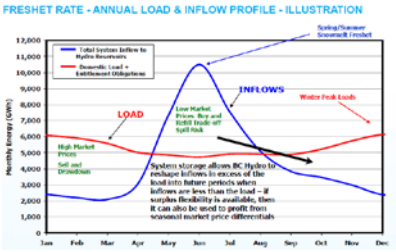

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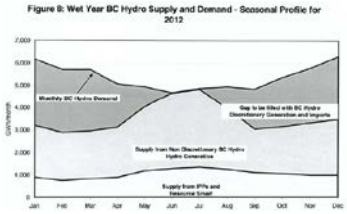

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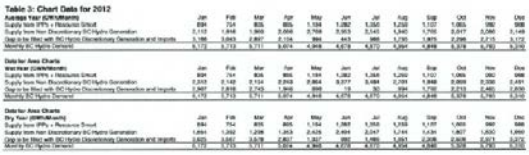

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Supply from Non Discretionary BC Hydro Generation	3,110	1,818	1,900	2,694	3,769	3,563	3,140	1,940	1,755	2,017	2,080	1,149
Gap to be filled with BC Hydro Discretionary Generation and Imports	3,168	3,663	2,867	2,174	994	415	360	1,730	1,875	2,298	2,215	3,172
Monthly BC Hydro Demand	6,172	5,732	5,771	5,674	4,948	4,078	4,872	4,964	4,848	5,378	5,782	5,309

Data for Area Charts

Wet Year (GWh/Month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
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Supply from Non Discretionary BC Hydro Generation	5,243	3,140	3,134	3,918	3,864	3,377	3,484	2,791	1,948	2,009	2,200	2,491
Gap to be filled with BC Hydro Discretionary Generation and Imports	1,487	2,838	2,743	1,948	898	19	30	884	1,742	2,313	2,480	2,830
Monthly BC Hydro Demand	6,172	5,732	5,711	5,674	4,948	4,078	4,872	4,964	4,848	5,378	5,782	5,309

Data for Area Charts

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Supply from IPPs + Resource Shed	894	754	805	805	1,184	1,082	1,368	1,292	1,157	1,065	982	988
Supply from Non Discretionary BC Hydro Generation	1,894	1,262	1,206	1,263	2,625	2,494	2,247	1,244	1,134	1,627	1,630	1,990
Gap to be filled with BC Hydro Discretionary Generation and Imports	3,423	3,657	3,678	2,607	1,317	502	1,165	3,431	2,558	2,686	3,011	3,331
Monthly BC Hydro Demand	6,172	5,733	5,711	5,674	4,948	4,078	4,872	4,964	4,848	5,378	5,782	5,309

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1.1.6 Please provide the full details of the constraints on the transmission line between Terrace and Kitimat that prevents BC Hydro during the May to July freshet period from using to the fullest extent possible the equichange and storage provisions in the 2007 electricity purchase agreement between Alcan and BC Hydro as approved by the British Columbia Utilities Commission on January 29, 2008 (“Alcan Agreement”).

RESPONSE:

The current rating on the transmission line between Terrace and Kitimat has not been the constraining issue associated with utilizing Equichange Services and Coordination provisions in the 2007 Rio Tinto Alcan EPA With respect to these provisions, please refer to BC Hydro’s response to CEBC IR 1.1.7.

1.0 Reference: Exhibit B-1, Application, Section 7.3.4 Proposed Freshet Rate Pilot

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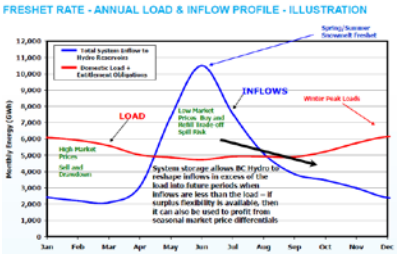
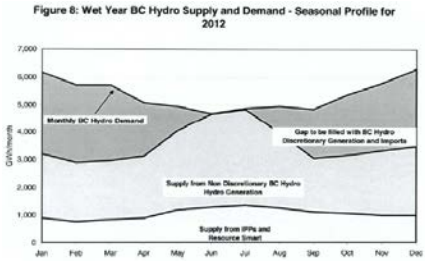


However, as the large note indicates, system inflows do not well define the problem because system storage is generally managed to reshape those flows.

In CEBC's view, BC Hydro has provided more useful information in the past by showing the load vs. discretionary and non-discretionary generation. An example of this is taken from the 2006 IEP/LTAP Hearing (Attachment to the response to IPPBC IR 1.15.2), a portion of which is shown below.



And, to accompany this and similar charts, BC Hydro included the information in tabular form:

Table 3: Chart Data for 2012

Average Year (GWh/Month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	835	865	1,184	1,282	1,356	1,259	1,157	1,065	982	988
Supply from Non Discretionary BC Hydro Generation	2,112	1,916	1,990	2,086	2,768	2,953	2,545	1,940	1,705	2,017	2,086	2,149
Gap to be filled with BC Hydro Discretionary Generation and Imports	3,166	3,043	2,887	2,124	994	443	988	1,795	1,915	2,296	2,715	3,172
Monthly BC Hydro Demand	6,172	5,713	5,711	5,074	4,946	4,678	4,870	4,994	4,848	5,378	5,783	6,310

Data for Area Charts Wet Year (GWh/Month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	835	865	1,184	1,282	1,356	1,259	1,157	1,065	982	988
Supply from Non Discretionary BC Hydro Generation	2,312	2,142	2,134	2,243	2,864	3,377	3,484	2,701	1,948	2,099	2,336	2,491
Gap to be filled with BC Hydro Discretionary Generation and Imports	2,967	2,818	2,743	1,966	898	19	30	994	1,742	2,213	2,465	2,830
Monthly BC Hydro Demand	6,172	5,713	5,711	5,074	4,946	4,678	4,870	4,954	4,848	5,378	5,783	6,310

Data for Area Charts Dry Year (GWh/Month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	835	865	1,184	1,282	1,356	1,259	1,157	1,065	982	988
Supply from Non Discretionary BC Hydro Generation	1,684	1,392	1,298	1,363	2,425	2,404	2,047	1,744	1,434	1,807	1,830	1,950
Gap to be filled with BC Hydro Discretionary Generation and Imports	3,625	3,567	3,578	2,827	1,337	992	1,466	1,991	2,206	2,506	2,971	3,372
Monthly BC Hydro Demand	6,172	5,713	5,711	5,074	4,946	4,678	4,870	4,954	4,848	5,378	5,783	6,310

CEBC found this format to be much more illustrative of the extent of the oversupply problem and, in the following information requests, seeks to use a similar format to:

1. clarify the recent and current extent of this "long-term recurring issue of energy oversupply,"
2. understand how known future events are expected to impact on this oversupply, and
3. explore various possible ways in which this oversupply situation could be mitigated, possibly with greater benefits to ratepayers than a freshet rate might bring.

1.1.7 Please provide the full details of BC Hydro's use of the equichange and storage provisions in the Agreement in each year from 2008 to 2015.

RESPONSE:

The Rio Tinto Alcan Equichange Services provisions are an operational tool which BC Hydro is already using to the practical extent possible to alleviate the freshet oversupply issue. BC Hydro has used this flexibility but only under limited conditions, and accordingly it is not an alternative to the proposed freshet pilot.

Key issues that preclude BC Hydro from using this flexibility includes Rio Tinto Alcan restrictions due to downstream flood risks, and high likelihood of spill at the project that makes the expected return on the storage operation very marginal. Nevertheless, to be responsive, total volume of storage for the requested years for the Equichange Coordination accounts are summarized below.

Storage at End of Year (GWh)	**Equichange**	**Coordination**
2007	**0**	**0**
2008	**32.2**	**37.3**
2009	**32.2**	**50.4**
2010	**0***	**0***
2011	**0**	**0**
2012	**0**	**0**
2013	**0**	**0**
2014	**0**	**0**
2015	**0**	**0**

*** All energy in the storage accounts was spilled, with no energy returned to BC Hydro. All storage into these accounts was carried out under negative price conditions at Mid C, thus still providing a trading benefit.**

1.0 Reference: Exhibit B-1, Application, Section 7.3.4 Proposed Freshet Rate Pilot

On pages 7-27 to 7-28, BC Hydro outlines its objectives for the proposed freshet rate, including the following:

"...2. Assist in the management of the freshet oversupply in the BC Hydro system by providing the option to:

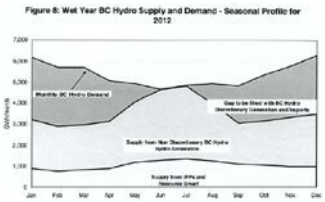
- Increase the ability to import cheap electricity during low priced periods;
- Reduce the volume of surplus energy being forced to export markets; and/or
- Reduce spill at BC Hydro facilities;

It further asserts that, "the freshet rate would encourage customers to increase electricity consumption during the freshet period (May-July), when BC Hydro has a long-term recurring issue of energy oversupply."

As an illustration of the problem, BC Hydro provided Figure 7-2, showing system inflows vs. monthly load. The following similar figure appeared at slide 29 of the Workshop #5 presentation material:

However, as the large note indicates, system inflows do not well define the problem because system storage is generally managed to reshape those flows.

In CEBC's view, BC Hydro has provided more useful information in the past by showing the load vs. discretionary and non-discretionary generation. An example of this is taken from the 2006 IEP/LTAP Hearing (Attachment to the response to IPPBC IR 1.15.2), a portion of which is shown below.



And, to accompany this and similar charts, BC Hydro included the information in tabular form:

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2. understand how known future events are expected to impact on this oversupply, and
3. explore various possible ways in which this oversupply situation could be mitigated, possibly with greater benefits to ratepayers than a freshet rate might bring.

1.1.8 If this transmission line is upgraded or replaced in order to serve Shell’s proposed LNG project at Kitimat or another LNG project, please provide the full details of BC Hydro’s ability to use to the fullest extent during the freshet period the equichange and storage provisions in the Agreement?

RESPONSE:

Transmission line ratings are not considered to be the constraining factor in the use of Equichange and Coordination accounts. Please refer to BC Hydro’s responses to CEBC IRs 1.1.6 and 1.1.7.

1.0 Reference: Exhibit B-1, Application, Section 7.3.4 Proposed Freshet Rate Pilot

On pages 7-27 to 7-28, BC Hydro outlines its objectives for the proposed freshet rate, including the following:

"...2. Assist in the management of the freshet oversupply in the BC Hydro system by providing the option to:

- Increase the ability to import cheap electricity during low priced periods;
- Reduce the volume of surplus energy being forced to export markets; and/or
- Reduce spill at BC Hydro facilities;

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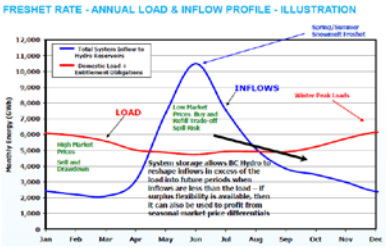

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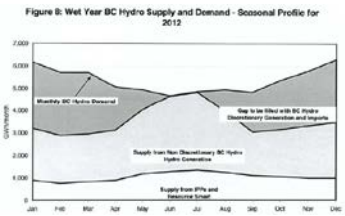

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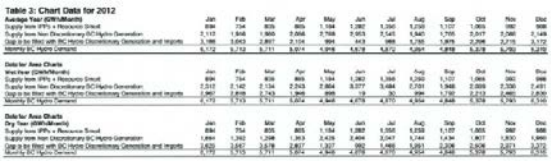

Table 3: Chart Data for 2012

Average Year (GWh/Month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	805	865	1,184	1,282	1,266	1,230	1,137	1,065	982	988
Supply from Non Discretionary BC Hydro Generation	2,117	1,958	1,909	2,056	2,798	2,953	2,541	1,941	1,755	2,017	2,390	2,149
Gap to be filled with BC Hydro Discretionary Generation and Imports	3,166	3,043	2,897	2,134	994	443	966	1,745	1,875	2,248	2,215	3,172
Monthly BC Hydro Demand	6,172	5,712	5,711	5,014	4,976	4,678	4,772	4,954	4,818	5,329	5,590	5,218

Data for Area Charts

Wet Year (GWh/Month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	805	865	1,184	1,282	1,266	1,230	1,137	1,065	982	988
Supply from Non Discretionary BC Hydro Generation	2,517	2,142	2,134	2,243	2,864	3,377	3,484	2,791	1,948	2,009	2,330	2,491
Gap to be filled with BC Hydro Discretionary Generation and Imports	2,967	2,816	2,743	1,906	898	19	20	894	1,730	2,213	2,480	2,830
Monthly BC Hydro Demand	6,378	5,713	5,711	5,014	4,946	4,678	4,770	4,954	4,846	5,287	5,792	5,148

Data for Area Charts

Dry Year (GWh/Month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Supply from IPPs + Resource Smart	894	754	805	865	1,184	1,282	1,266	1,230	1,137	1,065	982	988
Supply from Non Discretionary BC Hydro Generation	1,894	1,392	1,298	1,363	2,428	2,494	2,047	1,744	1,434	1,807	1,830	1,990
Gap to be filled with BC Hydro Discretionary Generation and Imports	3,420	3,567	3,608	2,827	1,372	902	1,460	2,981	2,246	2,424	2,921	2,172
Monthly BC Hydro Demand	6,172	5,713	5,711	5,054	4,984	4,678	4,773	4,954	4,818	5,296	5,732	5,150

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1.1.9 A single major LNG liquefaction plant (such as the Shell project) could require up to 10,000 GWh/yr if fully electrified, and the associated pipelines and upstream activities could require a similar amount of energy. Accordingly, if BC Hydro were to acquire only 50% of that single project’s additional upstream and downstream load, it could amount to an additional 1200 MW of load, on a 24/7 ongoing basis. What impact would this magnitude of additional industrial load have on the projected future freshet oversupply problem?

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the requested information cannot aid in the review of the 2015 RDA or the orders sought with respect to it. LNG Canada (the Shell project) is not expected to be in service within the two-year trial period of the freshet rate pilot.

Nevertheless, BC Hydro offers the following to be responsive. The decision of whether to electrify remains with LNG proponents. All large LNG proponents have indicated that they would self-power at least their compression cooling load. The impact that adding an additional load of 1,200 MW on a 24/7 basis has on the freshet oversupply would depend upon the characteristics of the resources that BC Hydro were to acquire to supply that load to maintain compliance with the *CEA* self-sufficiency requirement. To the extent that freshet energy heavy resources were to be acquired to supply even a fairly flat load, this would exacerbate the freshet oversupply.

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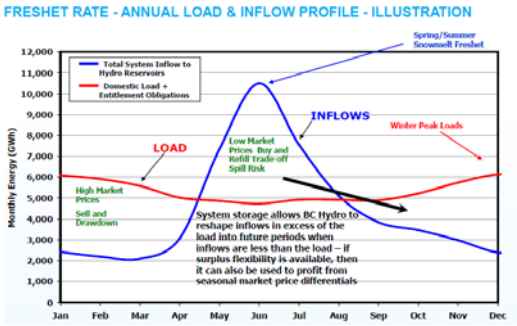

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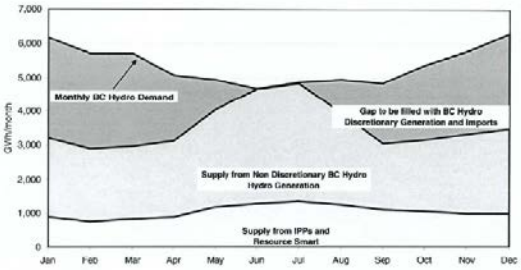
Figure 8: Wet Year BC Hydro Supply and Demand - Seasonal Profile for 2012



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Supply from Non Discretionary BC Hydro Generation	2,112	1,946	1,969	2,086	2,768	2,953	2,545	1,940	1,755	2,017	2,086	2,149
Gap to be filled with BC Hydro Discretionary Generation and Imports	3,166	3,043	2,897	2,104	994	443	968	1,755	1,975	2,296	2,715	3,172
Monthly BC Hydro Demand	6,172	5,713	5,711	5,074	4,946	4,678	4,870	4,954	4,848	5,378	5,793	6,310

Data for Area Charts

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Gap to be filled with BC Hydro Discretionary Generation and Imports	3,625	3,567	3,578	2,837	1,337	992	1,468	1,951	2,306	2,506	2,971	3,372
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1.1.10 BC Hydro has explored the possibility of building pumped storage facilities at many locations around the province, including a 500 MW facility at Mica. Assuming BC Hydro had such a 500 MW facility at Mica, please simulate how it would have operated during the past 4 years, from 2012 to 2015. In each of those years, how much freshet energy could have been purchased and effectively “stored” in the Kinbasket reservoir for sale at a more opportune time? Please also estimate how much of a price increase BC Hydro could have realized by reselling that energy in higher-priced periods during the year.

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the requested information cannot aid in the review of the 2015 RDA or the orders sought with respect to it. The IR requests that BC Hydro speculate with respect to the following:

- **Simulate how a hypothetical pumped storage project at Mica would have been operated during from 2012 to 2015; and**

- **In each of those years, determine much freshet energy could have been purchased and "effectively stored" in Kinbasket Reservoir for sale at what CEBC label "a more opportune time", including estimating how much of a price increase BC Hydro could have realized by reselling that energy in higher-priced periods during the year.**

As noted in the 2013 IRP, BC Hydro has no plans to develop a pump turbine or pump at Mica Generating Station in the 20 year planning horizon. The 2013 IRP assessment indicated that such a facility would cost more than $700 million and take more than five years to construct once regulatory approvals are secured.

2.0 Reference: Exhibit B-1, Section 2.2.1.2, page 2-5, Clean Energy Act

1.2.1 How are the rate classes and rate design in the Application consistent with section 2(h) of the Clean Energy Act which says: "to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas (GHGP emissions in B. C."?

RESPONSE:

In BC Hydro's view, the subsection 2(h) *CEA* British Columbia's energy objective to encourage switching from one kind of energy source or use to another that decreases GHG emissions in B. C. is not relevant to the determination of rate classes. Refer to section 4.1 of Exhibit B-1 for a list of criteria used by utilities and regulators to group customers into rate classes.

BC Hydro's rate design proposals are consistent with the subsection 2(h) *CEA* British Columbia's energy objective. No rate design proposal has as its main purpose to encourage a switch from the use of one kind of energy to another such that the switch would increase GHG emissions in B.C., which is prohibited with respect to those rates which are demand-side measures (the two rate design proposals which could be considered 'demand-side measure' as defined in section 1 of *CEA* are the RIB rate and RS 1823). As noted in the Workshop 9a/9b consideration memo (Exhibit B-1, Appendix C-3B, page 370 of 609), DSM initiatives for dwellings with multiple heating sources may lead to a minor increase in natural gas consumption e.g., replacing incandescent bulbs with LED may lead to more gas furnace use and replaced lost heat. However, any increase in natural gas consumption is eclipsed by the efficiency gains induced by the RIB rate (and DSM programs and codes and standards) that encourage customers to only consume electricity when its value to the customer is greater than BC Hydro's incremental costs and to install electric end uses that are efficient given this cost.

3.0 Reference: Exhibit B-1, Section 2.3.2.2, page 2-50, Energy Long-Run Marginal Cost

1.3.1 Why is there a price difference between bio-energy EPA renewals which on average are expected to be approximately $95/MWh and run-of-river renewals at approximately $70/MWh ($F2016). Will there be restrictions on delivery or differences in the price paid for bio-energy EPA renewals during the spring freshet?

RESPONSE:

BC Hydro expects there will be price differences between bio-energy EPA renewals and run-of-river EPA renewals because run-of-river hydroelectric projects are primarily civil works with costs that have been fully or largely recovered from ratepayers during the first EPA term and likely have minimal sustaining capital costs while biomass facilities will have greater ongoing costs for operations including biomass fuel, and contribute dependable capacity.

With regard to delivery restrictions or price differences during the spring freshet for the upcoming bio-energy EPA renewals, similar to past acquisition processes, BC Hydro expects to have restrictions on firm energy allocations and differences in the price paid for delivered energy based upon the then current time-of-delivery adjustment (i.e., 3 x 12) table.

As described in section 4.2.5.1 of the 2013 IRP, BC Hydro is targeting renewal of EPAs for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. Due to the fact that EPA renewals are related to existing projects for which the IPP's initial capital investment has been fully or largely recovered during the term of the initial EPA, BC Hydro expects to be able to negotiate a lower energy price than the initial EPA. In its EPA renewal negotiations, BC Hydro will consider the seller's opportunity cost, the electricity spot market, the cost of service for the seller's plant, and other factors such as the attributes of the energy produced and other non-energy benefits.

BC Hydro clarifies that the paragraph of the reference provided in Exhibit B-1, section 2.3.2.2 , page 2-50 should read:

> **On average, BC Hydro's opportunity costs are estimated to be approximately $95/MWh for bio-energy EPA renewals and approximately $70/MWh for run-of-river EPA renewals ($F2016). These values are consistent with a firm energy LRMC of $85/MWh ($F2013) between F2017 and to about F2030, adjusted for non-firm energy and dependable capacity. These values are point-in-time estimates of BC Hydro's average opportunity cost, as opposed to average prices expected to be paid for the EPA renewals.**

4.0 Reference: Exhibit B-1, Section 2.4.1, page 2-56, Bonbright Criteria

1.4.1 Why in an age of rapidly changing technology in the electricity industry such as roof top solar panels and battery storage systems that allow some users of electricity to become self-sufficient in electricity are the Bonbright criteria relevant in rate design?

RESPONSE:

There are eight Bonbright rate design criteria (refer to Table 2-7 of Exhibit B-1):

- **The issue of customer self-sufficiency through adoption of the two technologies referenced in the IR is largely, if not exclusively, a recovery of revenue requirement criterion. As noted in section 2.4.1.2 of Exhibit B-1, BC Hydro did not trade-off the Bonbright recovery of revenue requirement criterion against the other seven Bonbright criteria because subsection 5(d) of Direction No. 7 provides that the Commission may not lawfully set rates to recover more or less than BC Hydro's revenue requirement;**

- **The remaining seven Bonbright rate design criteria, such as the avoidance of undue discrimination, would need to be taken into account in rate design regardless of when Residential and commercial solar grid parity occurs.**

BC Hydro also observes that the CPUC, as part of the recent California Residential Rate Reform Decision (D.15-07-001),[1] used the Bonbright rate design criteria as rate design principles, modified to account for requirements found in the California Public Utilities Code and stakeholder comment. California has greater roof top solar panel penetration compared to BC Hydro's service area.

There is no evidence that through the adoption of roof top solar panels and battery storage systems, significant numbers of BC Hydro's customers will become self-sufficient over the 2015 RDA Module 1 timeframe, which is:

- **F2017 to F2019, the period over which BC Hydro is seeking Commission approval of pricing principles for the RIB rate and RS 1823; and**

- **The next ten years, the relevant period for assessing BC Hydro's energy and capacity LRMC for rate-making purposes.**

[1] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K024/153024891.PDF; refer to page 27.

4.0 Reference: Exhibit B-1, Section 2.4.1, page 2-56, Bonbright Criteria

1.4.2 Please explain how the business model, used by BCH for the purposes of the Application, factors in competition and rapid technological changes in the market place? How is BCH proposing to retain its customers through its rate class structure and rate design as its rates climb and the cost of electricity customer self-supply declines?

RESPONSE:

It is not clear to BC Hydro what form of "customer self-supply" CEBC is referring to in this IR. BC Hydro addressed Residential and/or Commercial customer self-supply in the form of roof top solar panels in its response to CEBC IR 1.4.1. BC Hydro interprets the IR as referring to Transmission Service customer-self-supply.

While the 2015 RDA is not a RRA (refer to section 1.3 of Exhibit B-1), BC Hydro notes the following:

- **For 2015 RDA Module 1, BC Hydro prioritized customer understanding, and in particular bill impacts, together with two other objectives (refer to sections 1.1.1 and 1.5.1 of Exhibit B-1). Customer understanding is one of the reasons for BC Hydro proposing RS 1823 F2017- F2019 pricing principle Option 1, which is supported by AMPC, CAPP and MABC. BC Hydro is also proposing to simplify rates where rates are overly complex and not meeting their intended purpose and where customer business planning is frustrated, such as with BC Hydro's proposed flat energy rate for the LGS rate class, some of which customers AMPC represents. AMPC supports the LGS flat energy rate proposal. All else equal, such simplification will make it easier for customers do business with BC Hydro;**

- **In response to the 2013 IEPR task force recommendation that BC Hydro examine ways to provide industrial customers with more options to reduce their electricity costs, BC Hydro explored Transmission Service rate options in the 2015 RDA stakeholder engagement process and with the support of AMPC, is proposing the freshet rate pilot; and**

- **As part of RDA Module 2, BC Hydro is committed to reforming TS 6 with a view to simplifying new Transmission Service customer connections while protecting existing customers.**

5.0 Reference: Exhibit B-1, Section 7.3.3.1, page 7-24, Retail Access

1.5.1 Why isn't the freshet pilot program a form of retail access? Why should BCH's customers be allowed to purchase electricity at market based rate while third parties are prohibited from providing electricity to these customers on similar terms and conditions, including price?

RESPONSE:

The freshet rate pilot is not a form of retail access because customers continue to buy all their energy from BC Hydro. In other words, the freshet rate does not result in direct or indirect provision of unbundled transmission service in BC Hydro's service area.

On page 7-25 of Exhibit B-1, BC Hydro stated that relative to retail access "the freshet rate pilot better balances offering Transmission Service customers choice with other ratepayers interests" because it can avoid "negatively impacting non-participating customers" without the "complexity required to mitigate negative impacts" (i.e., entry/exit fees, etc). Accordingly and consistent with section 14 of Direction No. 7, BC Hydro is not voluntarily applying to establish a retail access program as part of the 2015 RDA. In this regard, please refer to BC Hydro's response to BCUC IR 1.99.1.

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James D Burns+
Jeffrey B Lightfoot+
Christopher P Weafer+
Michael P Vaughan
Heather E Maconachie
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November 17, 2015

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica Hamilton, Commission Secretary

Dear Sirs/Mesdames:

Re: British Columbia Hydro and Power Authority 2015 Rate Design Application

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

A copy of this letter and attached Information Requests have also been forwarded to BC Hydro and registered interveners by e-mail.

Should you have any questions regarding the foregoing, please do not hesitate to contact the writer.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer
CPW/jlb
cc: CEC
cc: BC Hydro
cc: Registered Interveners

INTERLAW MEMBER OF INTERLAW, AN INTERNATIONAL ASSOCIATION OF INDEPENDENT LAW FIRMS IN MAJOR WORLD CENTRES

REQUESTOR NAME:	**Commercial Energy Consumers Association of British Columbia (CEC)**
IR ROUND NO:	**#1**
TO:	**British Columbia Hydro and Power Authority (BC Hydro)**
DATE:	**November 17, 2015**
PROJECT NO	**N/A**
APPLICATION NAME:	**2015 Rate Design Application**

INDEX

A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology 1

B. Chapter 3 – Cost of Service 10

C. Chapter 4 – Rate Class Determination 22

D. Chapter 5 – Residential Rate Design 23

E. Chapter 6 – General Service Rate Design 37

F. Chapter 7 – Transmission Service Rate Design 52

G. Chapter 8 – Electric Tariff Terms and Conditions 58

REQUESTOR NAME:	**Commercial Energy Consumers Association of British Columbia (CEC)**
IR ROUND NO:	**#1**
TO:	**British Columbia Hydro and Power Authority (BC Hydro)**
DATE:	**November 17, 2015**
PROJECT NO	**N/A**
APPLICATION NAME:	**2015 Rate Design Application**

A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

1. Reference: Exhibit B-1, page 2-4 and 2-5

BC Hydro's view is that these British Columbia's energy objectives are not legally binding on the Commission for rate design purposes:

- Subsections 44.2(5.1)(a), 46(3.3)(a) and 71(2.21)(a) of the *UCA* expressly provide that the Commission "must consider and be guided by … [the] British Columbia's energy objectives" for purposes of adjudicating BC Hydro's DSM expenditure schedules, Certificate of Public Convenience and Necessity applications and those Electricity Purchase Agreement (**EPA**) filings subject to a hearing;
- There is no corresponding requirement set out in sections 58 to 61 of the *UCA*, which contain the rate setting provisions.

The net result in BC Hydro's view is that the Commission may, but is not obliged to, consider and be guided by the British Columbia's energy objectives, subject to the proviso that in the event of a conflict between an energy objective and a rate-setting provision of the *UCA*, the latter must prevail.

1.1. Are there any instances in this Application in which BC Hydro identifies a conflict between an energy objective and a rate-setting provision of the UCA?

1.1.1. If yes, please identify those instances and explain why there is a conflict.

1.2. What, if any, instances have occurred for BC Hydro in the last 5 years in which there has been a conflict between the energy objectives of the province, and the rate-setting provisions of the UCA? Please explain.

2. Reference: Exhibit B-1, page 2-8

2.2.1.4 Special Direction No. 10

The 2012 amendments to Special Direction No. 10 to the Commission[43] (**SD 10**) are relevant to the discussion of the lower energy LRMC in section 2.3.2.2 below. Sections 1 and 3 of SD 10 provide that the Commission, in setting rates for BC Hydro, must use the planning criterion of average water. As detailed in footnote 15 in Chapter 1 in respect of the Electricity Self-Sufficiency Regulation, the 2012 change in planning criterion increases the combined reliance on BC Hydro's Heritage hydroelectric system non-firm energy backed by market reliance in F2017 by about 4,100 GWh/year, reducing the need for new energy resources.

2.1. Does BC Hydro anticipate changes to the Average Water determination over the next 10 years as a result of climate change? Please explain.

2.1.1. If yes, please discuss the changes that BC Hydro anticipates to the Average Water and how it would be accounted for in the current rate-setting process.

3. Reference: Exhibit B-1, page 2-14 and page 2-15

At Workshop 8a, BC Hydro set out its position that Policy Action No. 4 of the 2007 Energy Plan does not oblige the Commission to ignore the eight Bonbright rate design criteria in favour of a conservation objective or to prioritize the Bonbright efficiency criterion over the other seven criteria. BC Hydro implemented an inclining

1. Price signals that encourage efficient use and discourage inefficient use	Economic Efficiency	Energy LRMC reference; energy conservation (total GWh).
4. Customer understanding and acceptance, practical and cost effective to implement	Practicality	BC Hydro and stakeholder opinion with BC Hydro giving greater weighting to the views of customers taking service under the particular rate structure being assessed unless there are cost implications for other customer classes; Maximum and customer bill impact (%, including the 10% bill impact test); One-time implementation and sustaining costs (quantified if possible, qualitative ranking otherwise); Jurisdictional references provided the different legal and regulatory regimes, and customer characteristics, are taken into account (refer to section 2.4.2 below).
5. Freedom from controversies as to proper interpretation	Practicality	Proposed measurement is the same as for Bonbright criteria (4).

3.1. Does item 4 'customer understanding and acceptance, practical and cost-effective to implement' apply to item 1 'price signals that encourage efficient use and discourage inefficient use', so that it incorporates the concept of customers being able to explicitly recognize and respond to price signals, and is not just a separate and generic understanding and acceptance of the tariff rates?

3.2. If not, please explain why not.

4. Reference: Exhibit B-1, page 2-30 and 2-31 and Appendix C-1A(708/4902)

- BC Hydro grounded the 1991 RDA on four policy objectives, including that no customer bills should increase by more than 10 per cent. The 10 per cent level was a guideline. Reference was also made to a 'two-times rule' which states that if as a result of rate design bills were to increase by more than double the increase received on average by bills within the rate class, this would begin to

encroach on the realm of rate shock. The Commission accepted that in the circumstances of the 1991 RDA the two-times rule could be used as a "rough guideline", noting that it appeared to give BC Hydro more flexibility within the context of a potential 7 per cent revenue requirements increase.[66]

BC Hydro proposals related to RIB: Maintain 2013 Residential Inclining Block (RIB) approach - Maximum of 10% bill impact, representing all-in costs (consisting of RRA rate caps + DARR + rate changes due to rate rebalancing + rate changes due to rate design), to single most adversely impacted customer – to be used as a limit for modelling purposes	☐	☐	x	☐	*The 2015 RDA is an opportunity for a broader consideration of how rates in all customer classes can be structured to promote economic efficiency, appropriately share in the benefits of low cost heritage supply and protect households and business from well-defined rate shock thresholds or criteria.*

4.1. Please provide BC Hydro's views of the 'well-defined rate shock thresholds or criteria'.

4.1.1. Please discuss whether or not these criteria should be consistently applied across rate classes.

4.2. Does avoiding 'rate shock' take any priority over any or all of the Bonbright's principles? Please explain.

5. Reference: Exhibit B-1, page 2-38

- E-Plus rates: BC Hydro proposed to phase-out E-Plus rates over a 10-year period from April 1, 2008 to March 31, 2018. The Commission denied BC Hydro's proposal. Pursuant to 2007 RDA Direction 14, BC Hydro was instructed to "pay more attention to the exercise of its rights under the [E-Plus] Rate Schedules and to invest the necessary time and resources to ensure that its E-Plus customers comply with the Special Conditions of the [E-Plus] Rate Schedules ...". The Commission approved restricting the ability to transfer the E-Plus rate to a new customer by amending the Availability clause to state that the E-Plus rate is available "only in Premises where there has been no change in customer since April 1, 2008". Refer to section 5.3.2 of the Application for a description of how BC Hydro responded to 2007 RDA Direction 14 and for BC Hydro's proposal with respect to its E-Plus rates;

5.1. What was BC Hydro's rationale for phasing out the E –Plus rates in the 2007 RDA?
5.2. Do these reasons still exist or have circumstances altered since then? Please explain.
5.3. Please explain whether or not E-Plus rates could be considered similar but of course not the same as the proposed freshet rate.

6. Reference: Exhibit B-1, page 2-44 and 2-45

2.3.2.1 Smart Meter Infrastructure

BC Hydro's installation of smart meters is 99 per cent complete with over 1.9 million meters installed throughout BC Hydro's service area. The new metering system allowed BC Hydro to better understand the load characteristics of its distribution

voltage customers and to more accurately allocate costs within the F2016 COS study described in Chapter 3 of the Application. For example, in the 2007 RDA BC Hydro's COS study relied on a load research sample of about 400 residential customers and about 1,100 commercial customers. The collection of this data was done annually, took several months to complete and was labor intensive. Because the sample was so small, the customer class profiles created were general, sample redesign was not financially feasible and sample bias could have been an issue.

With smart metering, BC Hydro has been able to analyze daily consumption patterns for each individual customer while using a sample of approximately 45,000 customers to analyze hourly load shapes and conduct more in-depth load research. The additional data from smart metering has increased the accuracy of BC Hydro's load profile information which is a key input into cost allocation with the F2016 COS study. With the capability to create almost on-demand detailed customer load profiles, COS analysis, rate design and peak load forecasting can be improved. Going forward, BC Hydro will be able to use smart metering information to measure losses on individual feeders and further improve the distribution loss assumptions that are used in the F2016 COS study and some rates within the Electric Tariff.

6.1. Please provide a high level overview of the changes that BC Hydro discovered using the improved accuracy from its Smart Meter Information and how this impacted its load profile.

7. Reference: Exhibit B-1, page 2-48 and 2-54

3,000 GWh/year. Even with this amount of LNG load, the need for such an acquisition process is not until F2032. As described further in this section, BC Hydro currently has sufficient alternative cost-effective B.C.-based resources to meet expected future energy needs without LNG demand by:

- Pursuing the DSM target (2013 IRP Recommended Action 1); and
- Undertaking IPP EPA renewals and Site C (2013 IRP Recommended Actions 4 and 6) as the main elements to fill the identified energy gap after pursuit of the DSM target.

BC Hydro estimates that LNG projects could add between about 800 GWh to 6,600 GWh/year of additional energy demand, corresponding to about 100 MW to 800 MW of additional peak demand. Supplying the low- to mid-range of LNG load (up to about 3,000 GWh/year) will not have a material impact on the energy LRMC because BC Hydro has enough energy resources to serve such LNG load with the pursuit of the cost-effective B.C.-based resources listed above. However, potential LNG load is one source of demand uncertainty and therefore LRMC uncertainty.

- Natural gas-fired simple-cycle gas turbine generators (**SCGTs**) with a UCC of $88/kW-year. In the case where the expected LNG load of 3,000 GWh/year materializes, there is a need for about 400 MW of new system generating capacity resources. The 2013 IRP identified SCGTs located on the north coast to meet this need because of additional reliability benefits in that region.

7.1. Please provide BC Hydro's directional understanding with respect to the impact of falling oil prices on the likely size and timing of the potential LNG load.

7.1.1. Does BC Hydro anticipate that 3,000 GWh/year will be the likely load?

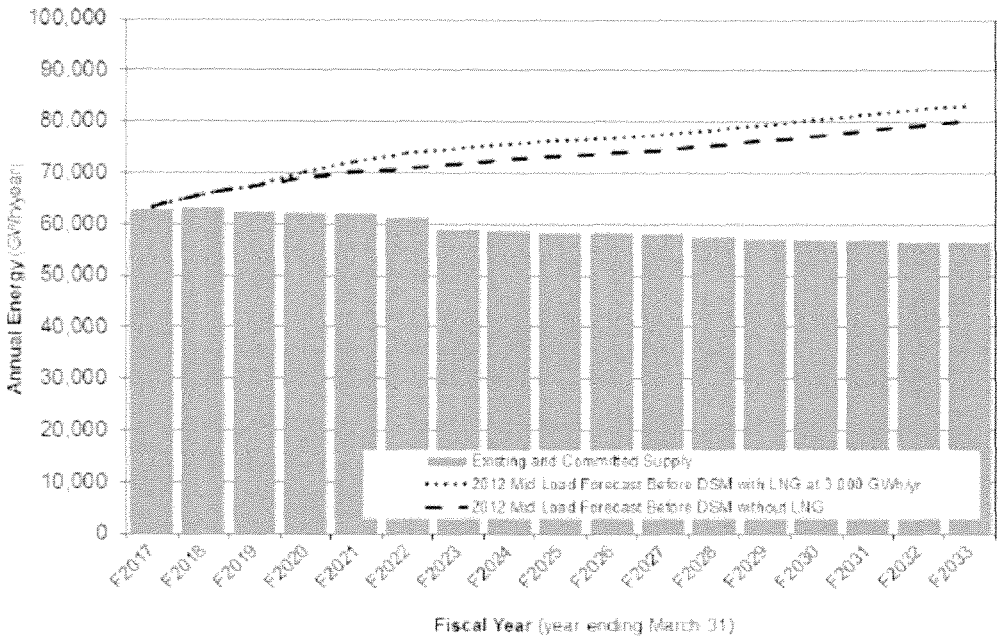
7.1.1.1. If yes, please provide BC Hydro's views as to when this would materialize, and over what period of time it might be brought in.

7.1.1.2. If no, please describe and provide quantification of BC Hydro's expectation of the LNG load for BC over the next 10 years.

8. Reference: Exhibit B-1, page 2-48 and 2-49

The 2013 IRP provides the analysis underpinning the energy LRB for BC Hydro's integrated system. A LRB is the difference between: (1) BC Hydro's annual load forecast, which projects BC Hydro customer demand over a 20-year period (in the case of the 2013 IRP this is the December 2012 Load Forecast) and (2) supply from existing and committed DSM and supply-side resources. There is a deficit or gap (i.e., a shortfall) if forecasted customer energy demand exceeds the existing and committed resources available to serve such load. Figure 2-1 is derived from the 2013 IRP and shows that there is a need for new energy resources beginning in F2017 without future DSM initiatives (including rate structures such as the RIB rate and RS 1823).

Figure 2-1 Energy LRB: Before Implementation of 2013 IRP Recommended Actions



The 2013 IRP proposes that BC Hydro meet the forecasted energy gap for the next 20 years predominantly by pursuing the DSM target, renewing some existing EPAs at the time they expire and Site C:

8.1. If BC Hydro expects that the LNG load will be significantly reduced, could an increase in DSM savings defer the need for future energy supply additions and or capacity additions? Please explain why or why not.

9. Reference: Exhibit B-1, page 2-55

Several Workshop 3 participants advanced two grounds for including a generation capacity value in the energy LRMC for purposes of the RIB Step 2 rate: (1) the RIB rate contains no demand charge; and (2) while the RIB is an energy conservation rate, it delivers anticipated capacity savings. In section 4.1.2 of the Workshop 3 consideration memo (copy at Appendix C-3A), BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction. BC Hydro also referenced the 2011 RIB Re-Pricing Decision where the Commission stated that the RIB Step 2 rate should be based on a "price signal for customers to understand *what is happening to the cost of energy* they will consume in the future" [emphasis added].[101] Use of BC Hydro's energy LRMC for energy conservation rate structures such as the RIB rate is consistent with past Commission RIB decisions noted in section 2.3.1.6 above. However, to illustrate the impacts of the addition of a generation capacity value to the LRMC, BC Hydro included the upper end of the energy LRMC range with a generation capacity value (the Rev 6 UCC) in various figures in Chapter 5.

9.1. Please confirm that residential customers do not have a clear understanding of RIB pricing and conservation as it relates to peak capacity reduction or energy conservation.

9.2. Please confirm that increasing capacity ultimately has a bearing on the costs that customers will bear in the future to meet their energy needs?

9.2.1. If not confirmed, please explain why not.

9.3. What is the total cost allocation for the class for each of energy, demand, and customer?

9.4. What is the proposed recovery in absolute dollars for the basic charge?

9.5. What is the proposed recovery for energy and demand from the energy revenues including Tier 1 and Tier 2?

10. Reference: Exhibit B-1, page 2-60

customers as to the price of acquiring marginal energy. Any lower price would incentivize inefficient electricity usage, and any higher price would discourage or unfairly penalize efficient usage. BC Hydro does not see a principled basis for setting the RIB Step 2 price without using LRMC as a referent. At Workshop 3 BC Hydro agreed with BCSEA that the pricing of the Step 2 rate in reference to the energy LRMC should not be regarded as a hard and fast rule. Refer to Attachment 1 (page 12) to the Workshop 9a/9b Consideration Memo (copy at Appendix C-3B of the Application); and to section 3.1.2 of the Workshop 3 Consideration Memo (copy at Appendix C-3A) for additional detail.

10.1. Please explain how a higher price discourages or 'unfairly penalizes' efficient usage?

10.2. Who would be the beneficiary, if any, of an unfair penalty from a higher than LRMC price?

B. Chapter 3 – Cost of Service

11. Reference: Exhibit B-1, Page 3-2

> BC Hydro would continue to submit Fully Allocated COS results with the Commission every year pursuant to 2007 RDA Direction 2. The Fully Allocated COS would reflect any Commission findings concerning the F2016 COS.

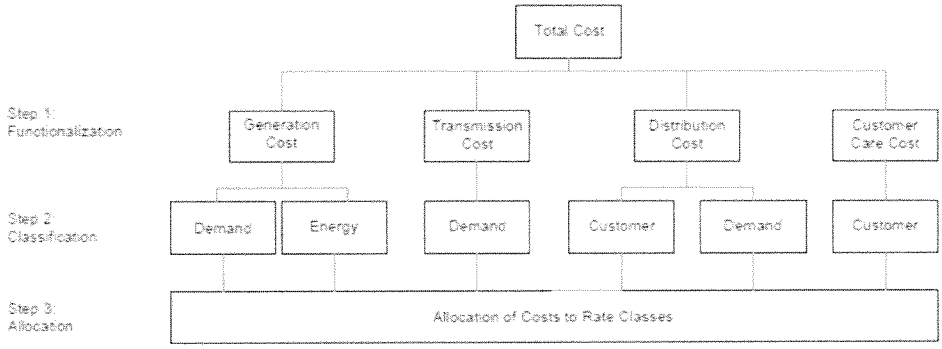
11.1. Please confirm that, because the LGIC has deferred the timing for rate rebalancing, the CEC has informed BC Hydro that it will not bring forward a COS expert to test the BC Hydro COS submissions for 2015 and that the CEC has requested, during consultation, that BC Hydro, for the proposed 2019 RDA which would include rate rebalancing, keep open the possibility that interveners be enabled to test the COS changes from 2007 RDA decision base forward to the 2019 RDA filing.

11.2. Please confirm that BC Hydro has informed the CEC that it would have no problem with the 2015 COS being constrained in terms of precedent to the 2015 RDA and its purposes, provided that in further consultation with the CEC that BC Hydro would identify the key areas of concern where it would be appropriate to the carry forward the 2007 RDA decision base to enable testing of the changes through to the 2019 RDA.

11.3. Please confirm that this further consultation has not yet occurred but that BC Hydro will engage in the further consultation with the CEC to identify the key areas of concern and that this will be done in time to provide the outcome as a filing in this regulatory proceeding.

12. Reference: Exhibit B-1, Page 3-4, Page 3-31

> Figure 3-1 Cost Allocation Methodology



20 Note that Generation energy is adjusted for losses prior to allocation. Before the pro
21 rata calculations are done, transmission and distribution losses of 6 per cent and
22 6 per cent respectively are added to the energy consumption of distribution
23 customers while transmission losses of 6 per cent are added to the energy
24 consumption of transmission voltage customers. These loss assumptions were
25 reviewed as part of the 2007 RDA and BC Hydro continues to believe they are valid
26 as discussed in section 3.8.2.1.

12.1. Please confirm that for the Figure 3-1 description of the methodology for cost of service allocations that the transmission and distribution systems do have energy components, which are not reflected for purposes of simplification, and that these energy components are related to losses and that these are the calculated losses of 6% and 6% above, which are then part of the generation energy allocation for transmission and distribution customers.

12.2. Please advise that for the 2007 RDA that the loss assumption of 6% additional losses on the distribution system included loss quantities for theft of energy.

12.3. Please provide the estimated loss due to theft of energy, which BC Hydro included in its SMI business plans, and provide this as a quantity in GWhs/year and provide it as a % of energy generated as well as a % of energy delivered to BC Hydro customers.

12.4. Please confirm that BC Hydro's SMI is helping it identify and eliminate theft of energy as a problem on its system.

12.5. Do the Distribution Load Shape Estimation calculations depend to some extent on fixed input assumptions about losses on the distribution system circuits and assumptions about hourly loading on those circuits?

12.6. Is it possible that changes in theft from the BC Hydro system may reflect in the more accurate actual metered calculations of losses, when they are available in the future, as a change from the assumption of 6% BC Hydro is currently using.

12.7. Please confirm that once BC Hydro has all of its SMI metering in place and substation circuit metering that BC Hydro may be able to reduce energy losses through more refined settings for managing voltage levels on its distribution circuits.

12.8. Are there any other activities BC Hydro is undertaking or is planning to undertake to better manage losses on the distribution system as a result of the SMI metering capabilities?

12.9. Is it possible that BC Hydro may see changes in the future to its energy loss calculations once it has fully taken advantage of its SMI initiative?

13. Reference: Exhibit B-1, Page 3-5

5 Historically, BC Hydro prepared COS studies using actual revenues, costs, energy
6 sales and customer load profiles from a recently completed fiscal year. If BC Hydro
7 followed past practice, the COS study would have been based on F2014 actuals
8 because F2015 information would not be available in time for the 2015 RDA filing.
9 There would have been a three-year misalignment between BC Hydro's rates and a
10 COS study based on actual costs (F2014). To avoid this disconnect, BC Hydro
11 prepared the F2016 COS study on a forecast basis using F2016 forecast information
12 from the approved F2016 RRA. Some historical information, such as load profiles by
13 rate class, is used in the F2016 COS study and this is discussed in section 3.5.4.

14 Further information concerning BC Hydro's F2016 RRA as used in the F2016 COS
15 study is found in sections 3.6.5, 3.7 and 3.8.

13.1. When will BC Hydro have actual F2015 data and or does BC Hydro have actual F2015 data now available?

13.2. Has BC Hydro compared its use of 2016 forecast data to its F2015 data and if so could BC Hydro please provide that comparison as it relates to differences in COS, which would be based on using forecast data versus actual data?

13.3. If BC Hydro has not yet done a comparison of F2015 actual with F2016 forecast data could BC Hydro please conduct such a comparison and provide the results as it may related to any differences the use of 2016 forecast data may be creating?

14. Reference: Exhibit B-1, Page 3-6

23 There is ample basis to continue to design rate structures with marginal cost pricing
24 while allocating BC Hydro's revenue requirement on an embedded cost basis. All

14.1. Please confirm that in this statement BC Hydro is confirming that it has marginal cost information available but not that it is intending to confirm that it will necessarily continue marginal cost rate structures, for instance where it is proposing flat rate structures for the base rate design.

15. Reference: Exhibit B-1, Page 3-8

12 The COS Methodology Review concludes that BC Hydro's COS methodology is
13 generally consistent with standard embedded COS methodologies. The one
14 exception is classification of Customer Care costs as 65 per cent demand and
15 35 per cent customer as mandated by 2007 RDA Direction 4; all electric utilities
16 surveyed classify Customer Care costs as 100 per cent customer. The COS
17 Methodology Review makes 18 recommendations. BC Hydro largely concurs with
18 these recommendations.

15.1. Please prepare a table of the 18 recommendations and identify those that BC Hydro agrees with and has implemented in this RDA COS study.

15.2. Where recommendation are presented as a multiple options please record each as a recommendation and show which one BC Hydro concurs with and which one it does not.

16. Reference: Exhibit B-1, Page 3-10

1 Table 3-1 Summary of 2007 RDA-Related COS
2 Methodology Changes

2007 RDA Direction	COS Methodology Change Proposed in 2015 RDA
Direction 6 – Functionalize DSM 90 per cent to Generation and 10 per cent to Transmission	Functionalize DSM to 90 per cent Generation, 5 per cent Transmission and 5 per cent Distribution on the basis that while DSM initiatives are primarily undertaken to defer Generation resources, they have some Transmission and Distribution deferral benefits. See section 3.6.6.
Direction 5 – Classify Heritage hydroelectric Generation 45 per cent energy/55 per cent demand on the basis that future Resource Smart additions at Revelstoke and Mica Generating Stations are predominantly capacity-related	Use BC Hydro integrated system Load Factor[125] calculation based on loads almost entirely served by Heritage hydroelectric supply (the impact of IPPs serving load is removed) resulting in a 55 per cent energy/45 per cent demand split. See section 3.7.1.
Direction 8 – Classify IPP purchases 100 per cent energy. BC Hydro is directed to prepare a study for its next RDA that examines and quantifies the capacity benefits associated with IPP EPAs	Use an approach where the fraction of IPP costs allocated to demand equals the ratio of IPP capacity benefits from the IPP EPA portfolio over IPP costs, resulting in a 93 per cent energy/7 per cent demand split. See section 3.7.3.
Direction 4 – Classify Distribution costs 65 per cent demand/35 per cent customer. BC Hydro is directed to conduct a minimum system and zero intercept analysis for inclusion in its next RDA	Sub-functionalize the Distribution system: (1) classify substations and the primary system as 10 per cent demand using Non-Coincident Peak[126] (NCP) allocator; (2) direct assign transformers, with 50 per cent demand/50 per cent customer classification for rate design purposes; (3) classify the secondary system and services as 50 per cent demand/50 per cent customer and use appropriate allocators; and (4) classify meters as 100 per cent customer on a weighted customer basis. BC Hydro conducted a minimum (system) study and zero intercept analysis, but has not used the results given the shortcomings outlined in section 3.7.7.
Direction 4 – Classify Customer Care costs 65 per cent demand/35 per cent customer	Classify Customer Care costs 100 per cent customer as such costs do not vary with demand levels (or energy usage) but only in proportion to the number of customers on the BC Hydro system. See section 3.7.9.

16.1. For each entry above please supply an additional column entry showing the impact on cost classification versus 2007 RDA methodology and changes to RC ratios as a result of the change.

17. Reference: Exhibit B-1, Page 3-11

Finally, a number of COS R/C ratios changed (irrespective of any proposed changes to the F2016 COS study methodology) despite using the same (2007 RDA Decision) methodology as the F2014 Fully Allocated COS.[127] This occurs for a variety of reasons including:

17.1. Please identify for each of the four items listed the difference in RC ratio attributable to the listed cause.

18. Reference: Exhibit B-1, Page 3-13

As described in section 2.3.2.1 of the Application, since the implementation of SMI in F2014 SMI daily register reads are available for almost all BC Hydro customers. Ratio expansions[130] can be done on a daily basis rather than an annual or monthly basis as they were in the past. Also, BC Hydro has a statistical sample of about 45,000 customers with hourly load information from which it can conduct more detailed load research. With the capability to create almost on-demand detailed customer load profiles, regulatory analysis, rate design and peak load forecasting have been improved. BC Hydro estimates that the new hourly sample of 45,000 would yield within 1 per cent accuracy at 99 per cent confidence level.

18.1. Please identify and quantify the impact of improved load research data on any cost allocations made or on the RC ratios resulting from the COS.
18.2. Please confirm that BC Hydro uses the actual load data for the purposes of the COS.
18.3. Please confirm that the transmission and distribution systems are planned and built based on meeting design load requirements for customers and not necessarily actual load used profiles.
18.4. Please discuss whether or not this difference between actual load data and design load planning could cause differences in cost allocations or RC ratios.

19. Reference: Exhibit B-1, Page 3-14

The subsidiary net income, which is derived primarily from Powerex Corp. (Powerex), is assigned to the Generation function on the basis that the income is associated with energy sales.

19.1. Please advise whether or not the subsidiary net income is deducted from the costs of energy.

19.2. Please describe how losses involved in the sale of energy and generation of net income in the subsidiary are allocated and advise whether or not the losses offset this income when it is being allocation.

19.3. Please advise whether or not the subsidiary net income is allocated all to energy or is there a split of the allocation between energy and demand.

20. Reference: Exhibit B-1, Page 3-15

3.6.4 Customer Care

The Customer Care function includes services related to revenue collection and customer account and relationship management, as well as planning and sustainment of the Information Technology (IT) infrastructure required to deliver these services. Revenue collection activities include meter reading, bill generation and delivery, billing exception identification and resolution, payment processing, collections and investigation of electricity theft. Customer account and relationship management are provided through mass market contact channels (call centre, internet portal) and dedicated account representatives for BC Hydro's largest customers, as well as resolution of claims and complaints.

20.1. Please describe what happens to costs involved with providing service to customers, such as connections, disconnections, trouble investigations and work orders for specific customer requirements.

20.2. Please describe what happens to costs involved in marketing services to customers.

21. Reference: Exhibit B-1, Page 3-17

associated with IT are approximately $112 million in the F2016 COS study and these are currently treated like a corporate expense and functionalized to all business groups using a high level O&M allocator.

21.1. When the IT costs are treated like a corporate expense and functionalized to all business groups are these allocations done on the basis of the annual expenditures for each of the business groups or some other methodology?

22. Reference: Exhibit B-1, Page 3-19

As part of the RRA process, T&D operating costs are already split between Transmission and Distribution using a methodology that originated in BC Hydro's 1997 Wholesale Transmission Service proceeding and involves a detailed review of all operating costs within T&D. For example, Line 23 on Schedule 5.4 of the RRA shows that 53.4 per cent of F2016 T&D operating cost is functionalized as Transmission while the remaining 46.6 per cent is functionalized as Distribution; refer to the F2016 COS model at Appendix E of the Application. BC Hydro relies on this information for F2016 COS purposes.

22.1. Is the 1997 Wholesale Transmission Service detailed review of all operating costs within T&D available as a report and is it on the record of this proceeding? If not please provide.

22.2. Please discuss what might have changed in the costing of T&D functions since 1997 that would warrant BC Hydro relying on this 1997 study.

23. Reference: Exhibit B-1,Page 3-19

At Workshop 2 BC Hydro identified DSM as a functionalization issue, and proposed a departure from the Commission's 2007 RDA Decision Direction 6 functionalizing DSM-related costs as 90 per cent Generation and 10 per cent Transmission to functionalizing DSM-related costs as 90 per cent Generation, 5 per cent Transmission and 5 per cent Distribution.

23.1. Please confirm that the purposes of DSM investment are to avoid the higher costs of future generation supply for all customers and to ensure that all customers have an opportunity to use their electric energy as efficiently as practicable.

23.2. Please confirm that most of the DSM expenditures and programs have been designed to save energy and that BC Hydro continues to focus on energy savings, though it has started to explore more program opportunities to focus on capacity savings.

23.3. Please confirm that in the long term energy savings that are applicable year round will have an impact of reducing the capacity requirements of the transmission and distribution system.

23.4. Please confirm that for a savings of 1 MW at a 50% load factor average over a year the energy savings would be worth approximately 90% of the savings and 10% would be

related to the capacity, while at a 30% load factor the savings split would be more like 84% energy and 16% capacity. (assume cost of new power $100/MWh and the cost of capacity $50/kw-year)

23.5. Please confirm that the above analysis provides a reasonable level of confirmation that BC Hydro's 90% Generation, 5% Transmission, and 5% Distribution represents a suitably appropriate allocation of DSM.

24. Reference: Exhibit B-1, Page 3-20

14 the underlying asset. The functionalization for several regulatory account amounts[135]
15 was adjusted, each with a small impact to total costs assigned by function. The
16 largest of these in F2016 was a change in the functionalization of the Rate
17 Smoothing regulatory account, an amount of $122.4 million in the F2016 RRA. This
18 amount was previously assigned to each function proportionate with functionalized
19 O&M. The COS Consultants recommended that this amount be functionalized

24.1. Please describe the source of the entry amounts being accumulated in the Rate Smoothing Regulatory Account and discuss what is giving rise to the variability which requires smoothing.

24.2. Why is the rate smoothing being done?

25. Reference: Exhibit B-1, Page 3-21

10 The classification of the interest on the deferral accounts was also updated to be
11 consistent with that used for Cost of Energy. This amount was previously classified
12 using the classification ratio applied to all of the Generation function. In F2016, this
13 change is applicable to an amount of $23.8 million.

25.1. Please provide a table of deferral account balances and the relevant interest applicable to each.

25.2. Please explain the appropriate alignment of each of the accounts to an appropriate functionalization methodology and explain why each is aligned.

26. Reference: Exhibit B-1, Page 3-24

12 However, as stated in section 2.1.2 of the Workshop 4 consideration memo,
13 BC Hydro believes that both the load factor and capacity factor approaches have
14 merit. As a result, and to respond to AMPC, Transmission Service customer and
15 CEC concerns with the system load factor approach, BC Hydro brought forward two
16 F2016 COS study sensitivities:

17 1. Forty-five per cent energy/55 per cent demand split resulting from a capacity
18 factor approach (Sensitivity Number 1); and

19 2. Fifty per cent energy/50 per cent demand split based on BC Hydro's historic
20 classification of Heritage hydroelectric facilities (Sensitivity Number 2). A
21 50 per cent energy/50 per cent demand split is a compromise approach that
22 recognizes the limitations of and roughly represents an average of the system
23 load factor and capacity factor approaches.

26.1. Please describe the merits of the capacity factor approach in contrast to the system load factor approach.

27. Reference: Exhibit B-1, Page 3-25

12 • FNG – use a load factor approach specific to the Fort Nelson service territory to
13 classify FNG's O&M and capital generation costs. This results in a 74 per cent
14 energy and 26 per cent demand classification. Fuel costs are classified as
15 100 per cent energy;

16 • PRG – For simplicity, use the system load factor with no adjustment for IPP
17 supply to classify PRG's O&M and capital generation costs. This results in a
18 60 per cent energy and 40 per cent demand classification. Fuel costs are
19 classified as 100 per cent energy; and

20 • Burrard – classify Burrard O&M and capital costs as 100 per cent demand with
21 associated fuel costs treated as 100 per cent energy.

27.1. For each of the thermal plants please describe when they are run during a year and why each is run.

27.2. Please supply the data supporting when the plants are run.

28. Reference: Exhibit B-1, Page 3-26

22 BC Hydro proposes to continue classifying the 90 per cent portion of DSM that has
23 been functionalized as Generation-related, in the same way as overall Generation
24 costs. As described in section 3.6.6, BC Hydro's rationale for functionalizing
25 90 per cent of DSM to Generation is that DSM expenditures are primarily incurred to
26 avoid generation-related costs, which also avoids the classification of those same
27 costs into energy and demand. Therefore, to be consistent with the rationale for

28.1. Please confirm that this approach to DSM would not account for a contribution to transmission and distribution capacity.

29. Reference: Exhibit B-1, Page 3-27 & 3-28

23 • Substations and primary system classified 100 per cent demand;
24 • Transformers classified 50 per cent demand and 50 per cent customer;
25 • Secondary/services asset category split 50 per cent secondary and 50 per cent
26 services:
1 ▸ Secondary portion classified 100 per cent demand;
2 ▸ Service portion classified 100 per cent customer; and
3 • Meters classified 100 per cent customer.

29.1. Please describe the transformers on the system which are being classified as 50% demand and 50% customer and elaborate on why this judgement is being made.

30. Reference: Exhibit B-1, Page 3-32

19 Generation demand-related and Transmission costs are typically allocated on the
20 basis of the system's CP demand because it is combined system demand at peak
21 times that drives Generation capacity and Transmission needs. A rate class's 4CP
22 allocation is calculated as a five-year average of the sum of that rate class's demand
23 at each winter month's peak hour divided by the sum of all rate classes' demand
24 during those same hours. Stakeholders providing Workshop 4-related written

30.1. Please confirm that the generation capacity and the transmission capacity in the system are designed to deliver the maximum design coincident peak forecast.

C. Chapter 4 – Rate Class Determination

31. Reference: Exhibit B-1, page 4-1

BC Hydro uses the expression 'segmentation' to refer to the creation of sub-classes of customers defined by certain characteristics. Potential segmentation falls into two categories: that which may be justifiable on a cost of service basis and that which

cannot. Additional segmentation based on cost of service can lead to increased transparency and better matching of costs and revenues.

31.1. Please explain the characteristics that make segmentation justifiable on a cost of service basis versus that which is not.

31.2. Will a sub-class be refused if it is not justifiable on a cost of service basis? Please explain.

32. Reference: Exhibit B-1, page 4-8

- The smallest general service customers tend to have lower load factors than MGS and LGS customers, as shown in Figure 4-1 below. Load factor is a customer's average demand divided by their peak demand. Low load factors are indicative of customers that are relatively more costly to serve, and load factor is therefore a consideration when evaluating rate class segmentation.[158] Cumulatively, more than 50 per cent of SGS customers have a load factor under 40 per cent, while that same load factor range applies to only around 30 per cent of MGS and LGS customers.

32.1. Can 'load factor' be described as a measure of the 'infrequency of use' of the customer?

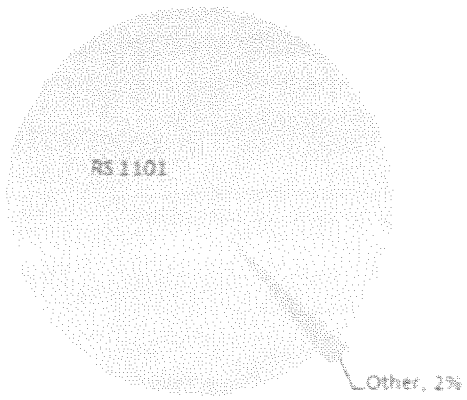
32.1.1. If no, please explain why not.

32.2. Please provide further clarification of why lower load factors are typically more costly to serve and or confirm that this is because the fixed capital investment costs to provide service will be spread over a smaller energy volume billing.

D. Chapter 5 – Residential Rate Design

33. Reference: Exhibit B-1, page 5-4

Figure 5-1 F2015 Residential Accounts



33.1. What sub-class(es) are included in the 2% that are included in "Other" ? Please explain.

34. Reference: Exhibit B-1, page 5-9

Figure 5-3 Total Consumption by Region (GWh)

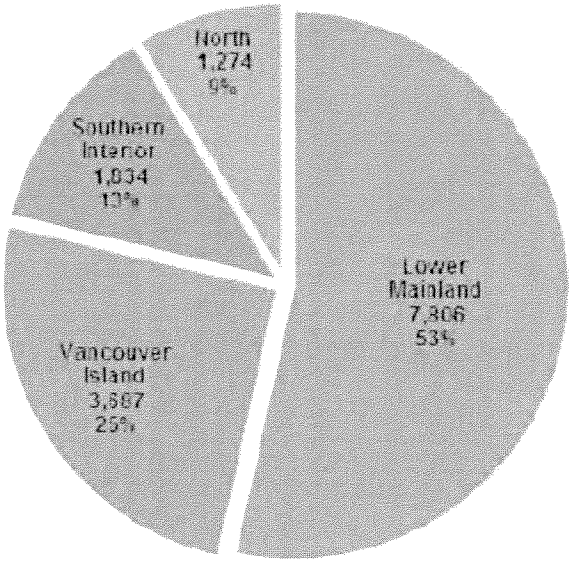
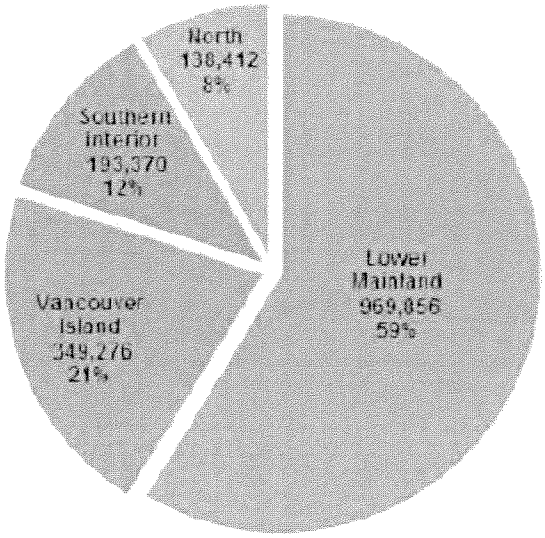


Figure 5-4 Customer Accounts by Region



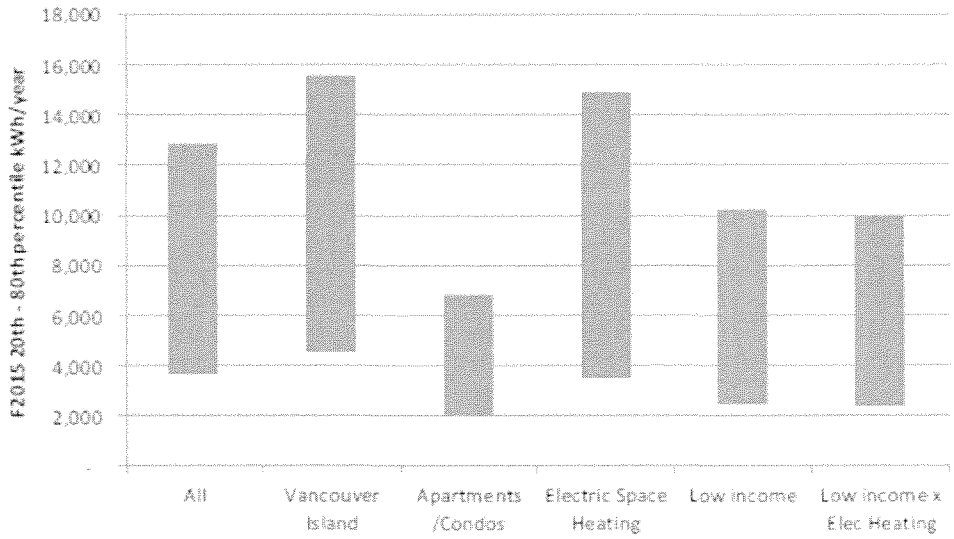
34.1. Please provide BC Hydro's views as to why Vancouver Island has a higher proportion of consumption relative to their proportion of customer count in comparison to those customers in other regions.

34.2. Please provide BC Hydro's views as to why Vancouver Lower Mainland has a lower proportion of consumption relative to their proportion of customer count in comparison to those customers in other regions.

35. Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



35.1. Why does BC Hydro include a separate geographic segment for Vancouver Island as opposed to segmenting it according to the same classifications as above?

35.2. Please provide the same information as that provided in Figure 5-12 for Vancouver Island.

35.3. Please confirm that all residential customers within the postage stamp area are exposed to the same RIB rates.

35.4. Approximately how many residential customers does BC Hydro have, within its 'postage stamp area', without access to natural gas in their service area?

35.5. Please confirm that those customers without access to natural gas but within the electricity postage stamp area would be exposed to the tier 2 rates for electricity, depending on their choice of electricity consumption for the functions that otherwise would be supplied by a natural gas service.

35.6. Is it fair to conclude that, based on the above table, use of electric space heating contributes about an additional 15% to residential consumption?

35.6.1. If not, please provide the approximate average increase, or a range of increases, in consumption that a residential customer with electric space heating would likely have versus a customer that does not.

35.7. Please provide the approximate bill increase, or range of increases, that a residential customer with electric space heating would likely experience versus a customer that does not.

35.8. Please confirm that a customer without access to natural gas would be required to 'trade-off' the costs of electricity heating against that of other fuels such as propane, heating oil or biomass fuels such as wood-burning.

35.8.1. If not confirmed, please provide BC Hydro's view of the trade-off customers without access to natural gas for heating experience with respect to their heating options.

35.9. Please confirm that electricity is a significantly cleaner option than propane, heating oil or the burning of wood.

35.9.1. If not confirmed, please explain why not.

35.10. Please provide BC Hydro's views as to the public interest issues involved in exposing those customers without access to natural gas to tier 2 pricing in their service area vis a vis those customers who do have access to natural gas for heating in their service area.

35.11. What would be the average estimated bill impact if those customers without access to natural gas in their service area were not exposed to the RIB rate?

35.12. What would be the total reduction in revenues to BC Hydro if those customers without access to natural gas in their service were not exposed to the RIB rate?

35.13. What would be the average bill impact to other residential customers if those customers without access to natural gas in their service area were not exposed to the RIB rate?

36. Reference: Exhibit B-1, page 5-18

- Price elasticity is generally larger for customer segments with higher consumption. As discussed in section 5.2.2.2 above, customers living in single family detached homes generally have higher consumption than those living in other dwelling types. The 2013 RIB Evaluation Report finds that customers living in single family detached houses demonstrate higher price

responsiveness than customers living in town houses, apartments or mobile homes (2013 RIB Evaluation Report, pages vi, 19). Section 5.2.2.2 also shows that customers with electric heat tend to have higher consumption than those that use other heating fuels. Price elasticity is higher among households with electric heat than those with non-electric heat (2013 RIB Evaluation Report, pages vi, 20); and

- Higher consumption is correlated with both higher awareness of the RIB rate and higher price elasticity; however, no firm conclusions can be drawn about how RIB awareness is related to customer price response (RIB Evaluation Report, pages vii, 28).

36.1. Would BC Hydro agree that customers with the lowest levels of consumption such as those living in apartments/condo may have lower price elasticity because they have less opportunity to reduce consumption due to such factors as fewer rooms in which to use heat or light.

36.1.1. If no, please explain why not.

37. Reference: Exhibit B-1, page 5-18 and page 5-18 and 5-19 to 5-20

- Higher consumption is correlated with both higher awareness of the RIB rate and higher price elasticity; however, no firm conclusions can be drawn about how RIB awareness is related to customer price response (RIB Evaluation Report, pages vii, 28).

- A total of 50 per cent of Residential customers appear to be aware of the RIB rate as of February 2012; and

Residential customer awareness of the RIB rate could be increased. BC Hydro responded that it may be possible to further increase customer awareness but this would come at a cost. Awareness efforts have continued since the October 2008 initial launch by including RIB rate messaging in other communications where appropriate (e.g., Power Smart residential DSM program materials, email correspondence with billing notices). However, a

broader marketing campaign would be necessary to ensure that RIB-specific messaging was promoted.[182]

37.1. What are the estimated costs of further increasing residential customer awareness of the RIB? Please provide quantification and relate this to the estimated level of awareness that could be achieved at the cost.

37.2. What, if any, plans does BC Hydro have to raise awareness of the RIB pricing? Please provide an overview with a timeframe of when they will be introduced and the expected costs.

38. Reference: Exhibit B-1, page 5-18 and page 5-23

- The total amount of the household electricity bill serves as the greatest incentive to manage electricity consumption among residential customers, followed by electricity prices.

2. As for conservation savings, a flat rate will likely result in a reduction in conservation because most customers are facing a reduction in their marginal price relative to the RIB rate;

3. Bill impacts are part of the Bonbright customer understanding and acceptance criterion. BC Hydro's primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers. As discussed at Workshop 9a, under a flat rate bills would go up for most customers, including low income customers, while bills would go down for larger consuming residential customers. Figure 5-13 and Figure 5-14, and Table 5-3 and Table 5-4, illustrate the estimated bill impact distribution for flattening of the RIB rate in F2017 (relative to BC Hydro's RIB Pricing Principles):

38.1. Please rationalize the three concepts that :

a) the total household electricity bill is a greater triggering factor for conservation than 'electricity prices' ,

b) most customers will see a rate increase and

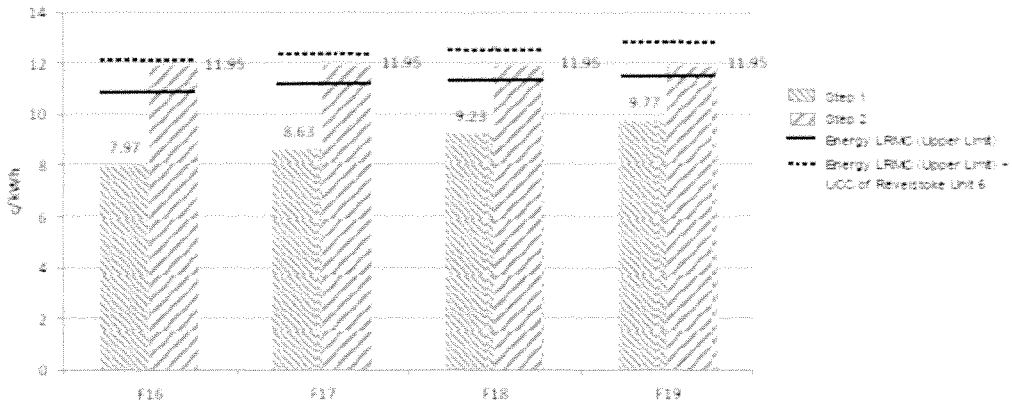
c) a flat rate will result in a reduction in conservation because most customers are facing a reduction in their marginal price relative to the RIB rate.

38.1.1. To the extent that conservation is reduced as a result of a flat rate, does the conservation reduction only come from those larger residential customers whose bills would go down? Please explain.

39. Reference: Exhibit B-1, page 5-35 and page 5-19

Option 2 would apply the rate increases to the Step 1 energy rate and basic charge only while holding the Step 2 energy rate at its current level, which results in narrowing the differential between the Step 1 and Step 2 energy rates over time. Under Option 2, the Step 2 energy rate would be approximately equal to the energy LRMC upper limit by F2019, with a forecast loss of conservation in comparison to Option 1. Higher bill impacts for most customers, including low income customers, would also be expected under Option 2. Option 2 is depicted in Figure 5-19.

Figure 5-19 Pricing Principle Option 2, F2017-F2019



Residential customer awareness of the RIB rate could be increased. BC Hydro responded that it may be possible to further increase customer awareness but this would come at a cost. Awareness efforts have continued since the October 2008 initial launch by including RIB rate messaging in other communications where appropriate (e.g., Power Smart residential DSM program materials, email correspondence with billing notices). However, a

39.1. Please provide an overview of any evidence that BC Hydro has with respect to the relationship between the magnitude of the difference between the Step 1 energy rate and the Step 2 energy rate and the responsiveness of customers to the RIB rate?

39.2. Please confirm that costs invested in creating an improvement in customer awareness and understanding of the RIB rate would be better served with a larger discrepancy between the Step 1 and Step 2 rates.

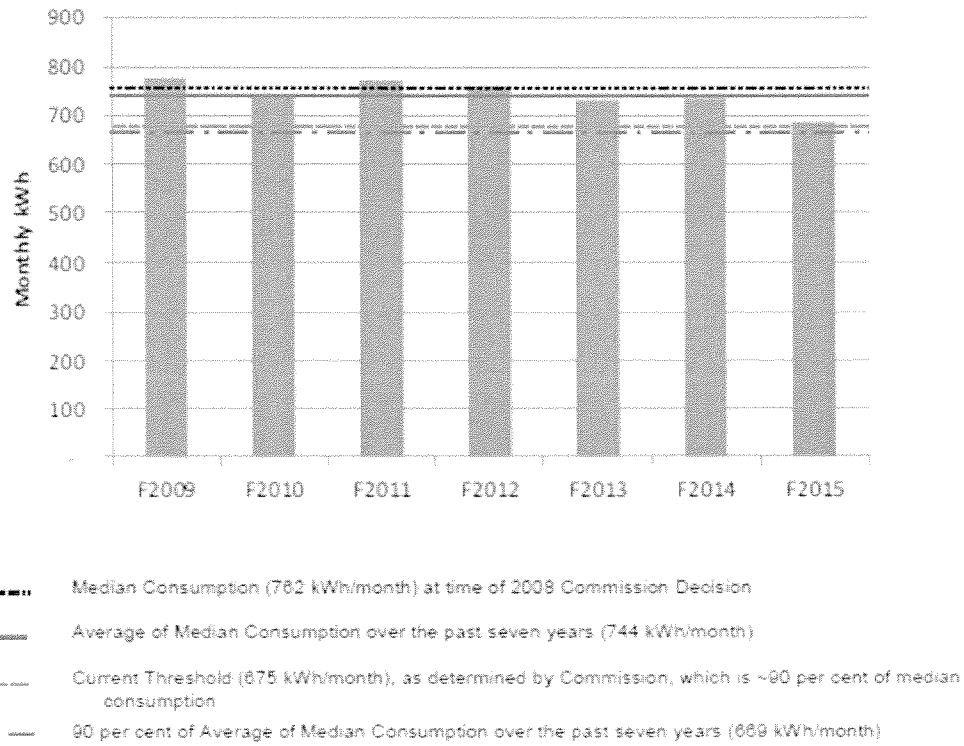
39.2.1. If not confirmed, please explain why not.

40. Reference: Exhibit B-1, page 5-43

5.2.5.4 Step 1/Step 2 Threshold

BC Hydro proposes no change to the existing Step 1/Step 2 threshold. The current threshold of 675 kWh per month reflects typical residential use, as it still represents approximately 90 per cent of the monthly median consumption given seven years of consumption data to date. This is shown by Figure 5-25 and Table 5-11 below.

Figure 5-25 Median Consumption per Month[196]



40.1. Why is the average consumption over the last 7 years the appropriate period to use, when the consumption appears to be clearly declining in recent years?

41. Reference: Exhibit B-1 page 5-45

Table 5-11 Median Consumption per Month

	Monthly Median (kWh)*	90% of the Monthly Median (kWh)
F2009	777	699
F2010	739	665
F2011	772	695
F2012	762	686
F2013	733	660
F2014	734	661
F2015	689	620
Seven-Year Average	744	669
Threshold set from 2008 Commission Decision, page 107	Based on 762	675

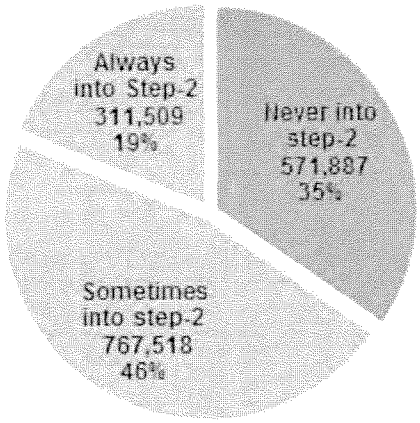
* Computed based on the same methodology as the 2008 RIB Application which includes all customers in RS 1101 with consumption between 1,200 kWh/year and 120,000 kWh/year. The monthly median of each year is computed as the median annual consumption divided by 12.

41.1. Please confirm that, or otherwise revise, the calculation of threshold based on 90% of the monthly median consumption using the last five years of data would be 585 KWh/month?

41.2. Please confirm that, or otherwise revise, the calculation of threshold based on 90% of the monthly median consumption using the last three years of data would be 597 KWh/month.

42. Reference: Exhibit B-1, page 5-45

Figure 5-26 Step 2 Exposure, all Accounts



42.1. Please revise the chart using 90% of the monthly median consumption using the last five years of data would be 597 KWh/month.

42.2. Please revise the chart using 90% of the monthly median consumption using the last three years of data would be 597 KWh/month.

43. Reference: Exhibit B-1, page 5-49

RS 1105 energy rate for F2016 is 5.22 cents/kWh and there is no basic charge. There are approximately 7,500 Residential E-Plus customers. Residential E-Plus customers represent a small portion of the Residential customer revenues (approximately $4.7 million of $1.9 billion (F2014)).

E-Plus rates were introduced in 1987 to residential and commercial customers. The purpose of the rates was to market surplus energy that would have been spilled because at the time consistent access to the spot market was not available. As part of the 2007 RDA Decision,[199] the Commission approved restricting the ability to transfer the E-Plus rate to a new customer by amending the RS 1105 Availability clause to state that the E-Plus rate is available "only in Premises where there has been no change in customer since April 1, 2008".

The 2007 RDA Decision contains Residential E-Plus-related directions relevant to or to be addressed as part of the 2015 RDA, summarized in Table 5-12.

43.1. Are there any commercial E-Plus remaining?
43.1.1. If yes, how many E-Plus commercial accounts are there?
43.1.2. If not, please explain why not.

44. Exhibit B-1, page 5-52

5.3.4 BC Hydro Proposal and Stakeholder Engagement

As described in section 2.2.3.5 of the Application, BC Hydro engaged E-Plus customers through a letter dated February 24, 2015 seeking feedback on the E-Plus rate as well as holding two open houses held in Nanaimo and Victoria on April 1 and April 2, 2015. BC Hydro received approximately 3,700 Residential E-Plus customer responses to the February 24, 2015 letter (about 45 per cent of the total number of Residential E-Plus customers). The vast majority of respondents support Option 1 for a number of reasons including:

1. The E-Plus rate is a contract between BC Hydro and the customer (37 per cent of comments);

2. Investments in back-up systems were made in good faith (36 per cent of comments);
3. Electricity affordability (36 per cent); and
4. The closed rate will end under attrition given the generally older age of E-Plus customers (21 per cent).

44.1. Are the E-Plus customers predominantly on Vancouver Island?

44.1.1. If so, please explain why this situation has developed.

44.1.2. If no, why did BC Hydro only hold open houses in Vancouver Island?

45. Reference: Exhibit B-1, page 5-50 and page 5-53 and page 5-55 and page 5-56

BC Hydro has never interrupted E-Plus load. Special Condition 1 of RS 1105 restricts BC Hydro's right to interrupt the supply of electricity; there must be a "surplus hydro energy" and "the service cannot be provided economically from other energy sources". This is very different language than the typical interruptible rate provisions whereby BC Hydro will only provide service when it has available energy and capacity to do so.

- Ending the E-Plus program would impose considerable financial hardship on users, almost all of whom are seniors;

- The proposed changes to Special Condition 1 will allow for the Residential E-Plus rate to be practically interruptible. BC Hydro proposes the following language for Special Condition 1 as shown on the amended RS 1105 in Appendix F-1D: "*BC Hydro will provide electricity under this rate schedule only to the extent that it has energy and capacity to do so. BC Hydro may, at any time and from time to time, interrupt the supply of electricity under this rate schedule where BC Hydro does not have sufficient energy or capacity*". This language aligns with interruption provisions in the recently Commission approved Shore Power Rates.[203] The proposed language is also generally consistent with Commission Order No. G-37-90[204] which approved interruption criteria for E-Plus service as follows: "*BC Hydro may, at any time and from time to time, interrupt the supply of energy under this Rate Schedule*". This point is expanded on in BC Hydro's response to BCSEA written question 1.6 provided in Attachment 6 to the Workshop 9a/9b consideration memo at Appendix C-3B.

In summary, Option 3 ensures that customers who use the E-Plus rate would continue to receive the current discount, while also ensuring that the rate is truly interruptible and serves a useful function as was intended when the discount was offered.

ahead" (refer to section 7.3.2 of the Application for additional detail). BC Hydro proposes the following as business practices: (i) the issuance of a 'seasonal notice' each year prior to the November-February winter months reminding Residential E-Plus customers that they are served on an interruptible rate. This seasonal notice would be given to all Residential E-Plus customers through auto-dialer, e-mail or letter; (ii) up to one week's notice that an interruption event is likely to occur. This notice would happen through auto-dialer, e-mail or letter. The interruption itself would occur by manual or automatic means or by written notice as set in Special Condition 3 of RS 1105.

46. While the proposed changes to Special Condition 1 would allow for the E-Plus rate to be practically interruptible and align with language in the Shore Power Rates, is it likely that the E-Plus service will ever actually experience an interruption?

46.1. If yes, how often is such an interruption likely to occur?

46.2. If yes, would customers always receive a notice that an interruption would occur, or could this occur with no notice period at all?

47. Reference: Exhibit B-1, page 5-58

In the context of *UCA* sections 58 to 61 rate setting, low income rates are likely to be seen as unduly preferential to low-income customers or unduly discriminatory to the remaining customers who subsidize those rates because the low income rate would be based on the personal characteristics of the customer, divorced from the cost to deliver electricity to the premises. BC Hydro outlined this position at Workshops 1, 3 and 9a, and section 2.1.2 of the Workshop 3 consideration memo (found at Appendix C3-A).

This position accords with the majority of Canadian electric utilities and utility commissions, where cost-based ratemaking is the most widely-used standard for evaluating whether rates are 'fair, just and not unduly discriminatory'. Canadian electric utilities typically offer targeted low income DSM programs, as opposed to low income rates.

47.1. Please provide BC Hydro's views as to a % difference that would constitute 'unduly preferential' to any group of customers.

47.2. Please confirm that there is considerable variation in the cost to deliver electricity to different premises between geographic regions, housing types, urban density and many other factors influencing costs which are absorbed in postage stamp rates.

47.2.1. If confirmed, please confirm that the principle of cost-causation is frequently subordinated to the greater public interest perceived in having postage stamp rates.

48. Reference: Exhibit B-1, page 5-65

Disclosure of Total Household Income - Total household income is the most essential parameter needed to classify a customer household in the REUS as possibly being low income. When a missing value occurs on this parameter, the customer household has to be either left as unclassified in their low income status or other secondary information has to be leveraged to make an informed classification. In this case, the mean and median household income levels for the household's postal code area together with the area's incidence of low income are taken into account to inform the decision on the low income status. For example, if the mean and median income levels for the postal code area are $65,000, and the incidence of low income in that neighbourhood is say 2 per cent, then the household in question has a very low probability of actually being of low income status. Note that in this case, $65,000 is greater than even the largest of the LICO thresholds.

48.1. Please confirm that a low income household can also be 'asset rich' such as in a situation in which a retired party is living on savings, but has significant debt-free assets.

48.2. If confirmed, does BC Hydro have any plans to assess the affordability of electricity service based on assets?

48.2.1. If yes, please identify any plans BC Hydro has to assess affordability from an asset perspective.

49. Reference: Exhibit B-1, page 5-69

- Electricity consumption by housing type within region. Due primarily to the fact that they rely on electricity for space heating, residential customers on Vancouver Island lead all four regions in average annual consumption at 11,776 kWh. Average household consumption was higher in the Southern Interior (10,211 kWh) and the North (9,894 kWh) than it was in the Lower Mainland (8,634 kWh), most likely due to the relatively heavier electrical demand for space heating and space cooling in those regions (2014 REUS, page 233).

49.1. Why do residential customers on Vancouver Island rely primarily on electricity for space heating? Please explain.

E. Chapter 6 – General Service Rate Design

50. Reference: Exhibit B-1, Page 6-8

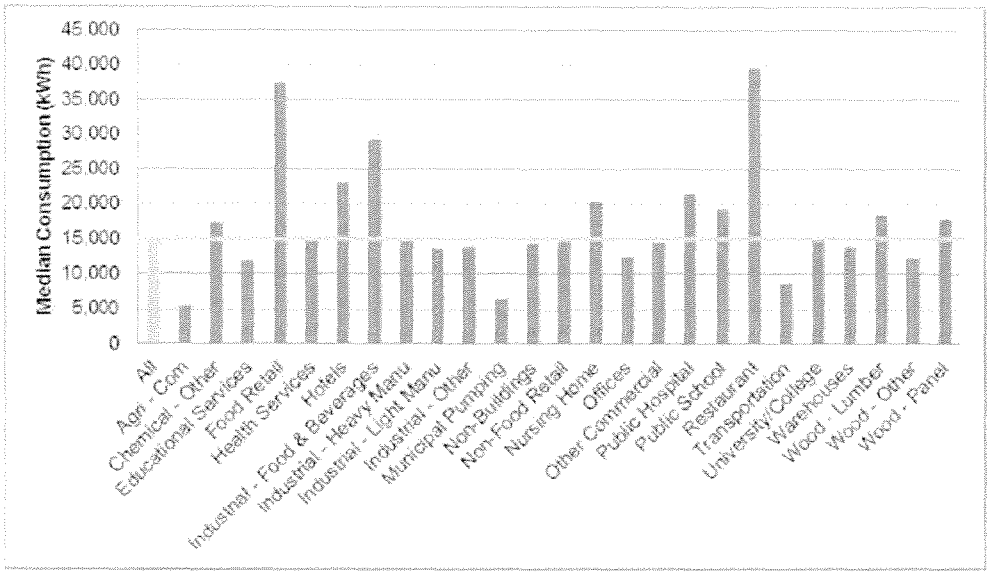
BC Hydro proposes maintaining the existing SGS rate structure of a flat energy rate and a basic charge. BC Hydro seeks approval of a one-time increase to the RS 13xx basic charge to 45 per cent recovery of customer-related costs attributable to the SGS class in the F2016 COS study, and a one-time offsetting reduction of the energy rate, to maintain forecast revenue neutrality based on the SGS revenue target calculated using any applicable rate increases arising from the F2017 RRA. The proposal results in the following illustrative SGS pricing assuming the F2018 rate cap increase of 3.5 per cent: a flat energy rate for all kWh of approximately 11.39 cents/kWh and a basic charge of approximately 33.12 cents/day (F2018).

50.1. Please confirm that the increase in basic charge recovery is related to customer costs only and is not related to any demand costs, which are all subsumed in the SGS energy charge.

50.2. Please describe the demand related costs for SGS as a percentage of the total SGS energy revenue (BCUC IR -53) in the F2016 COS and provide the absolute dollar amount being used.

51. Reference: Exhibit B-1, Page 6-9

11 Figure 6-3 Median SGS Consumption by Site Type



51.1. Please confirm that for each of the median values shown above there would be a significant distribution of the SGS customers on either side of the median value and that this in addition to the data shown in Figure 6-3 is part of the information that leads BC Hydro to conclude that the heterogeneity of the rate class is too diverse to provide a single rate structure solution for providing appropriate price signals as efficiency incentives.

51.2. To the extent that BC Hydro has the statistical measure of the dispersion of the distribution around the median values could BC Hydro please provide that as well?

52. Reference: Exhibit B-1, Page 6-11

1 SGS demand charge would also require a demand meter which not all SGS
2 customers have. The requirement for a demand meter on all SGS customers makes
3 the demand charge less practical and cost-effective to administer.

52.1. Please confirm that virtually all SGS customers have BC Hydro's SMI smart meters and that these meters can record the customer demand for energy over the particular monitored measurement interval.

53. Reference: Exhibit B-1, Page 6-11

At Workshop 11a, BC Hydro indicated that no SGS rate structure issues had been identified through the 2015 RDA stakeholder engagement process. There was general agreement among stakeholders that there is not a strong basis to depart from the existing SGS rate structure.

53.1. Please confirm that while a flat rate is preferred as the base rate for SGS by general agreement among stakeholders and BC Hydro that this is applicable to Module 1 and that BC Hydro has indicated in the consultation process that it will be open to discussing alternative options for providing incentives in Module 2.

54. Reference: Exhibit B-1, Page 6-10 & 6-14

Table 6-2 Alternative SGS Pricing

Pricing Element (F2017)	BC Hydro Proposal (Increase basic charge to 45% of customer-related costs)	Status Quo
Energy rate (cents/kWh)	11.01	11.16
Basic charge (cents/day)	32.00	23.47

Table 6-3 Annual bill impacts of an increase in the SGS Basic Charge to recover 45 per cent of customer-related costs

Percentile by Consumption	Annual kWh	F2017 Annual Bill Status Quo ($)	F2017 Annual Bill BC Hydro Proposal ($)	Annual Bill Difference between F2017 BC Hydro Proposal and F2017 Status Quo ($)	Annual Bill Difference between F2017 BC Hydro Proposal and F2017 Status Quo (%)	Bill Impact (%) of F2017 BC Hydro Proposal (vs. F2016 Rates)
Min	1	86	117	31	36	42
10	2,001	309	337	28	9	13
20	4,773	618	642	24	4	8
30	7,797	956	975	19	2	6
40	11,184	1,334	1,348	14	1	5
50	15,288	1,792	1,800	8	0	4
60	20,648	2,390	2,390	0	0	4
70	28,435	3,259	3,247	-12	0	-4
80	40,838	4,643	4,613	-30	-1	-3
90	65,174	7,359	7,292	-67	-1	-3
Max	615,810	68,810	67,918	-892	-1	-3

54.1. Please expand on how the proposed changes implement Bonbright's fairness principles with regard to cost causation for the low usage customers, whose bills would be impacted and how it implements fairness for the higher usage customers with regard to their cost causation.

55. Reference: Exhibit B-1, Page 6-14 & 6-15

The MGS Proposal would result in the following illustrative charges in F2018: a flat energy rate for all kWh of approximately 8.83 cents/kWh; a flat demand charge of approximately $4.92 per kW (reflecting BC Hydro's preferred 35 per cent level of cost recovery); and a basic charge of about 24.29 cents per day. BC Hydro proposes to continue with the current monthly minimum charge definition. These

55.1. Please confirm that as BC Hydro has discussed in its consultation with the CEC this proposal for a flat rate is intended for Module 1 and that BC Hydro will be open in

Module 2 to options which may address providing a conservation price signal complementary with the flat rate as the base rate.

55.2. Please confirm that the MGS flat rate level is below the BC Hydro LRMC on a going forward basis.

56. Reference: Exhibit B-1, Page 6-15 & 6-16

- A basic charge and a monthly minimum charge. The current MGS basic charge is 22.57 cents/day. The MGS monthly minimum charge is 50 per cent of the highest maximum demand charge billed in any billing period in the on-peak period of November through March during the immediately preceding eleven billing periods.

56.1. Please discuss the rationale for having each of a basic charge, demand charge and monthly minimum charge in the rate structure.

57. Reference: Exhibit B-1, Page 6-19

Table 6-6 Existing MGS Demand Charges (F2016)

First 35 kW of Billing Demand per Billing Period (Tier 1)	$0.00 per kW
Next 115 kW of Billing Demand per Billing Period (Tier 2)	$5.50 per kW
All additional kW of Billing Demand per Billing Period (Tier 3)	$10.55 per kW

Most jurisdictions have flat or declining demand charges. The key issue associated with the existing MGS three-step inclining block demand charge is that it does not align with BC Hydro's cost to serve MGS customer peak demand, which is generally flat on a $/kW basis.

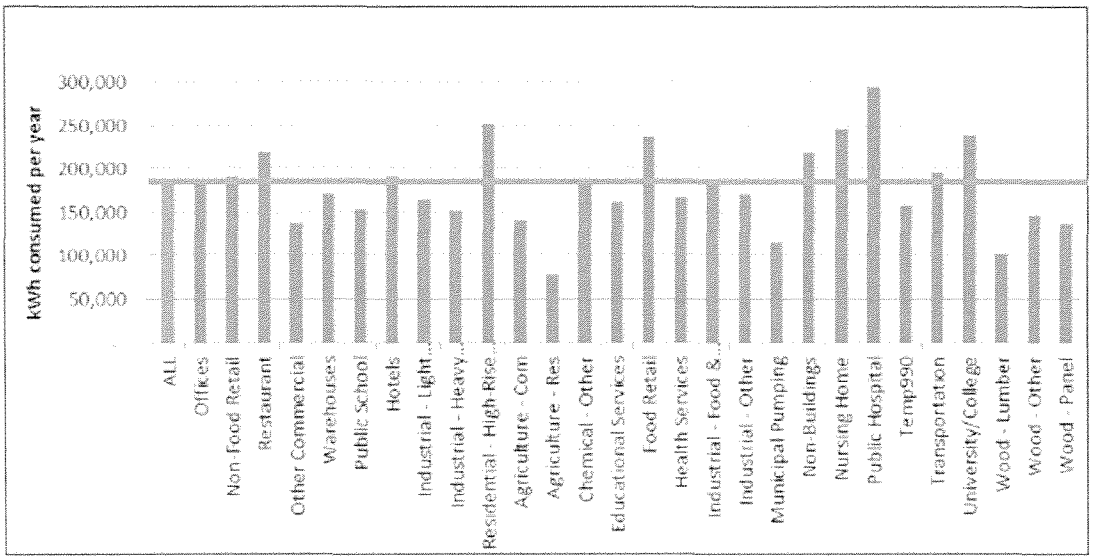
57.1. Please confirm that MGS customers, depending upon their kW demand will see demand charges increase/(decrease) linearly, in absolute dollar charges, as their kW demand may increase/(decrease).

57.2. Please confirm that a single price signal for demand will provide simplicity, for understanding, relative to a 2 or 3 tier demand price.

57.3. Please confirm that in the long term the incremental cost of new capacity to service demand is expected to increase substantially from the current expected incremental cost and that this is because the opportunities to add inexpensive capacity on the BC Hydro system are close to being all used and or committed.

58. Reference: Exhibit B-1, Page 6-21

1 Figure 6-5 Median MGS Consumption by Site Type



58.1. Please confirm that for each of the median values shown above there would be a significant distribution of the MGS customers on either side of the median value and that this in addition to the data shown in Figure 6-5 is part of the information that leads BC Hydro to conclude that the heterogeneity of the rate class is too diverse to provide a single rate structure solution for providing appropriate price signals as efficiency incentives.

58.2. To the extent that BC Hydro has the statistical measure of the dispersion of the distribution around the median values could BC Hydro please provide that as well?

59. Reference: Exhibit B-1, Page 6-22

17 The evaluation of these multiple lines of evidence indicated that the customer
18 response to the MGS two-part energy rate was considerably less than forecast.
19 Awareness and demonstrated understanding of the MGS rates was low. Evaluated
20 net energy savings for MGS rate were not statistically different than zero in 2011,
21 2012 and F2014, relative to calendar year 2010, as compared to a forecast
22 conservation savings of about 140 GWh/year.[237]

59.1. Please also confirm that with a 3 year rolling average price signal the MGS class of customers would not necessarily have a sustained payback on any initiatives they might take to create an economic justification for the investment.

59.2. Please confirm that this situation, of an inadequate economic justification, can also be a factor with respect to the fact that MGS customers did not appear to have a significant uptake of the price signal to result in energy savings.

60. Reference: Exhibit B-1, Page 6-23

18 In addition, BC Hydro carries forward in this Application an increase to the flat
19 demand charge under alternative (1) above to recover 35 per cent of
20 demand-related costs allocated to the MGS class in the 2016 COS study, an
21 increase from the existing 15 per cent recovery under the current demand charge.
22 The MGS rate alternatives brought forward into the 2015 RDA from the stakeholder
23 engagement processes are summarized in Table 6-9.

60.1. In assessing the demand charge to be allocated to the MGS class and how much to recover in the rate structure please provide the percentage portion of demand charge that is associated with system generation assets and the portion associated with transmission and distribution assets.

60.2. Please provide the absolute amount of the demand related costs allocated to the MGS class in the F2016 COS study.

60.3. Please confirm that system generation demand is planned in the BC Hydro system based on aggregate demand and would likely not be significantly influenced by individual customer demand profiles.

60.4. Please confirm that the demand for the T&D system can be more specifically localized to specific customer demand profiles and is managed in a planning sense through a completely different process than the system generation demand.

61. Reference: Exhibit B-1, Page 6-30

comparison to the total number of customers in each class. The amount of MGS and LGS demand ratchet revenue is a very small percentage of total MGS and LGS class revenue.

Table 6-11 Summary of F2015 demand ratchet charges, MGS and LGS

F2015 Demand Ratchet Charge	MGS	LGS
Total Customers Incurring Demand Ratchet	211	213
Percentage of Total Customers of Class	~ 1	~ 3
Total Demand Ratchet Revenue	$122,744	$1,794,043
Percentage of Total Revenue	~ 0.04	~ 0.2

61.1. Given how few customers are affected by the demand ratchet and how little revenue is impacted by the demand ratchet does BC Hydro's argument, that with so little effect BC Hydro would prefer to retain the ratchet, apply in reverse resulting in an argument that there is little reason to keep the ratchet?

62. Reference: Exhibit B-1, Page 6-32

Table 6-12 MGS Rate Estimates for Rate Structure Transition in F2017

MGS	F2016	F2017 Status Quo	F2017 BC Hydro Proposal (35% Demand Recovery)	F2017 Sensitivity (15% Demand Recovery)
Basic cents/day	22.57	23.47	23.47	23.47
Demand $/kW				
T1		–	4.76 Flat	2.14 Flat
T2	5.50	5.72		
T3	10.55	10.97		
Energy cents/kwh				
T1	9.89	10.33	8.54 Flat	9.35 Flat
T2	6.90	7.21		
Part 2	9.90	10.10		
Minimum	3.30	3.43		

62.1. Please confirm that the energy charged at Part 2 or Tier 1 will have a lower energy rate under BC Hydro's proposal the energy charged at Tier 2 will have a higher rate.

62.2. Please provide the quantities of energy charged at each of T1, T2, and Part 2.

62.3. Please confirm that with customers not responding to price signals, fairness issues become a priority in the rate design considerations and that this is primarily what BC Hydro's proposal is designed to respond to.

63. Reference: Exhibit B-1, Page 6-36 & 6-37

Figure 6-6 F2017 Bill Impacts less RRA – BC Hydro MGS Proposal (Demand 35 Per Cent Recovery)

Annual Consumption kWh

Highest kw

Load Factor *	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%			5.8%	2.8%	6.8%	14.0%	20.1%	22.3%	23.9%	25.1%	26.0%	26.8%	27.4%	27.9%	28.3%	28.7%	29.0%
20%				2.6%	3.4%	6.6%	8.3%	8.4%	6.0%	4.6%	8.4%	7.9%	8.1%	10.1%	10.9%	11.6%	12.2%
30%	1.0%	0.2%	1.3%	0.3%	1.1%	5.3%	7.1%	5.6%	3.5%	2.7%	1.1%	0.2%	1.5%	1.1%	1.5%	0.6%	1.5%
40%	1.1%	1.1%	1.2%	1.2%	1.2%	4.8%	6.7%	4.5%	2.8%	1.2%	0.0%	0.3%	1.7%	2.5%	2.7%	3.6%	4.5%
50%	4.1%	4.3%	4.4%	4.4%	4.4%	4.4%	6.3%	3.8%	2.1%	0.8%	0.2%	1.1%	2.5%	3.3%	3.9%	4.8%	5.8%
60%	4.1%	4.5%	4.6%	4.6%	4.6%	4.6%	6.2%	3.5%	1.8%	0.1%	1.1%	2.2%	3.2%	3.8%	4.5%	5.3%	6.0%
70%	7.6%	8.0%	8.1%	8.2%	8.2%	8.2%	7.9%	5.9%	3.3%	1.2%	1.2%	2.0%	3.5%	4.3%	5.0%	6.0%	6.9%
80%	9.7%	9.2%	8.9%	9.3%	9.9%	9.4%	9.0%	4.8%	1.3%	1.0%	1.8%	2.9%	3.8%	4.5%	5.9%	5.9%	6.5%
90%	8.5%	10.0%	10.2%	10.2%	10.5%	10.5%	9.9%	5.7%	2.1%	0.5%	1.0%	3.1%	4.1%	4.8%	5.9%	6.3%	6.8%

Lowest kw

Red underline indicates bill impact higher than RRA

Blue oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load

Figure 6-7 F2017 Bill Impacts less RRA – MGS Demand Sensitivity (15 Per Cent Recovery)

Annual Consumption kWh

Highest kw

Load Factor *	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%			13.3%	21.2%	24.7%	30.5%	35.0%	37.4%	38.7%	39.0%	40.4%	41.0%	41.5%	41.9%	42.2%	42.5%	42.8%
20%	4.5%	5.2%	6.5%	6.4%	11.7%	14.1%	16.2%	14.5%	13.2%	12.9%	14.6%	15.9%	17.6%	17.9%	18.6%	19.3%	19.9%
30%	1.5%	2.4%	1.3%	1.2%	5.4%	8.9%	10.7%	8.2%	7.1%	5.8%	4.5%	3.9%	3.2%	2.6%	3.0%	4.3%	5.2%
40%	1.9%	2.5%	3.0%	2.0%	3.8%	5.4%	7.0%	5.2%	3.5%	2.1%	0.6%	1.3%	0.6%	1.3%	2.2%	2.7%	3.2%
50%	3.3%	3.4%	3.6%	3.5%	3.4%	3.4%	5.3%	3.0%	1.3%	0.3%	1.0%	2.7%	2.3%	3.2%	3.9%	4.6%	5.0%
60%	4.2%	4.4%	4.5%	4.5%	4.5%	4.5%	4.1%	1.3%	0.6%	1.2%	2.5%	3.5%	3.5%	4.2%	4.9%	5.2%	5.8%
70%	4.8%	5.1%	5.2%	5.2%	5.2%	5.2%	4.9%	2.4%	1.0%	3.5%	4.8%	5.8%	6.3%	7.0%	7.4%	8.0%	8.6%
80%	5.3%	5.6%	5.7%	5.7%	5.7%	5.7%	5.5%	3.8%	2.0%	5.0%	6.6%	7.8%	8.3%	8.9%	9.4%	10.2%	10.7%
90%	5.7%	6.0%	6.1%	6.1%	6.1%	6.1%	5.7%	4.4%	2.2%	6.1%	7.8%	8.9%	9.7%	10.5%	11.1%	11.7%	12.3%

Lowest kw

Red underline indicates bill impact higher than RRA

Blue oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load

63.1. Please confirm that while the increased recovery of demand charge reduces the unfairness in rewarding efficient load factor use of the BC Hydro system the differences between low load factor customers and high load factor customers does not completely redress the issue but does significantly mitigate the issue.

64. Reference: Exhibit B-1, Page 6-38

The LGS Proposal would result in the following illustrative charges in F2018: a flat energy rate for all kWh of approximately 5.56 cents/kWh; a flat demand charge of approximately $11.21 per kW (reflecting BC Hydro's preferred 65 per cent level of cost recovery); and a basic charge of approximately 24.29 cents per day. BC Hydro proposes to continue with the current monthly minimum charge definition. These illustrative charges are calculated assuming the F2018 rate cap increase of 3.5 per cent. Final F2018 LGS pricing will be determined by the F2017 RRA decision.

64.1. In assessing the demand charge to be allocated to the LGS class and how much to recover in the rate structure please provide the percentage portion of demand charge that is associated with system generation assets and the portion associated with transmission and distribution assets.

64.2. Please provide the absolute amount of the demand related costs allocated to the LGS class in the F2016 COS study.

64.3. Please confirm that system generation demand is planned in the BC Hydro system based on aggregate demand and would likely not be significantly influenced by individual LGS customer demand profiles.

64.4. Please confirm that the demand for the T&D system can be more specifically localized to specific customer demand profiles and is managed in a planning sense through a completely different process than the system generation demand.

65. Reference: Exhibit B-1, Page 6-40

Table 6-14 Existing LGS Energy Rates (F2016)

Part 1 Energy Rate – Tier 1 (cents/kWh)	10.66
Part 1 Energy Rate – Tier 2 (cents/kWh)	5.13
Part 2 Energy Rate (cents/kWh)	9.90

65.1. Please confirm that the price signal difference, while significant, is nonetheless not relevant for conservation because BC Hydro cannot detect and cannot plan to rely on conservation from the rate structure.

65.2. Please confirm that, because of the 3 year rolling average effect, one of the factors for customers, in considering the price signal, is that the economic benefit from investing in making savings has a very limited payback, in terms of the marginal price signal.

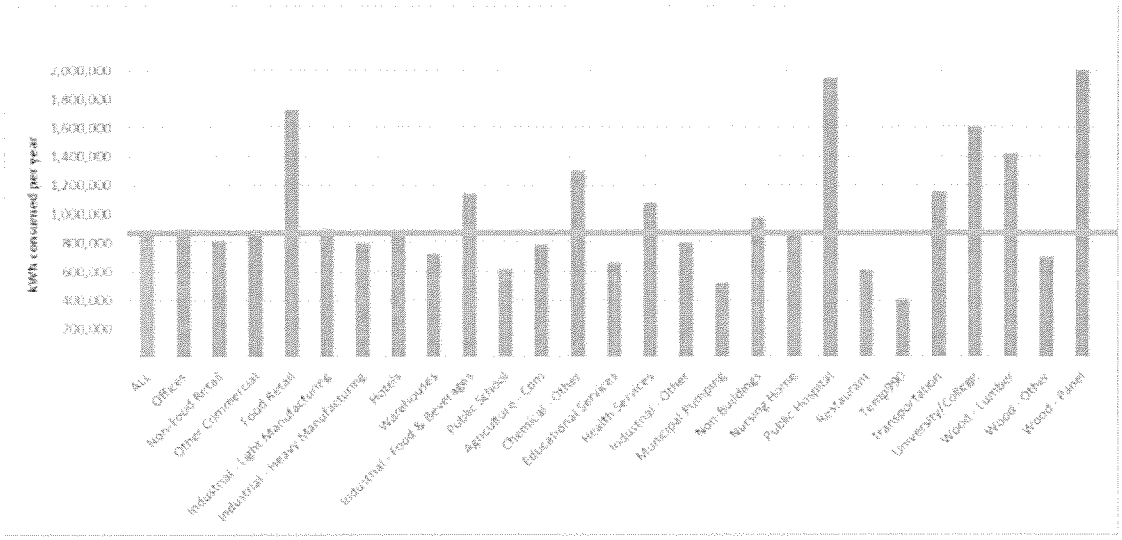
66. Reference: Exhibit B-1, Page 6-43

BC Hydro has a three-step inclining block demand charge for the LGS rate class which is the same structure and the same charges as applicable to the MGS rate class set out in Table 6-6. The key issue with the LGS demand structure is the same key issue identified with respect to the MGS demand structure in section 6.3.2.2; the LGS three-step inclining block demand charge does not align with BC Hydro's cost to serve LGS customer peak demand.

66.1. Please confirm that each kW of demand aggregates to create the same cost causation for the need to supply capacity for the BC Hydro system peak as every other kW of demand.

67. Reference: Exhibit B-1, 6-45

Figure 6-9 Median LGS Consumption by Site Type



67.1. Please confirm that for each of the median values shown above there would be a significant distribution of the LGS customers on either side of the median value and that this in addition to the data shown in Figure 6-9 is part of the information that leads BC Hydro to conclude that the heterogeneity of the rate class is too diverse to provide a single rate structure solution for providing appropriate price signals as efficiency incentives.

67.2. To the extent that BC Hydro has the statistical measure of the dispersion of the distribution around the median values could BC Hydro please provide that as well?

68. Reference: Exhibit B-1, Page 6-53

- AMPC and CEC, who represent LGS customers, favoured the LS-5 flat energy rate with a BC Hydro commitment to explore alternative concepts. AMPC considered that the current baseline approach is not sufficiently flexible for larger LGS customers who tend to experience significant changes in operations and conservation investments. AMPC suggests that a LGS TSR-Like Rate similar to RS 1823 where baselines can be individually administered would be more appropriate and effective for the largest LGS customers (Viterra also strongly favoured a LGS TSR-Like Rate targeted to larger LGS customers);[244]

68.1. Please confirm that when LGS customers were presented with alternatives they were only presented the screened alternative options and were not presented with the idea that other alternatives may be explored in Module 2, which may address the incentives they are looking for to enable them to invest cost-effectively in conservation and efficiency.

68.2. Please confirm that for those customers who have found that there is some incentive in the LGS rate structure it may be possible for them through Module 2 or other approaches to ensure that they do not lose the benefits of being able to invest in conservation and efficiency.

68.3. Please confirm that particularly for customers who have growth related issues or variable production issues with the LGS rate structure SQ, the provisions intended to help mitigate these issues have either not worked well for the customers or have added to BC Hydro's administrative complexity costs.

69. Reference: Exhibit B-1, Page 6-56

1. The LGS Flat Energy rate and LGS Flat Demand Charge are its preferred LGS rate structures to carry forward to the 2015 RDA, which is supported by many LGS customers and organizations representing such customers, and most other stakeholders;

69.1. Please confirm that the 3 step demand charge was originated and was applicable to the General Service rate class when it was not segmented into three groups, SGS, MGS and LGS.

69.2. Please confirm that the BC Hydro proposed approach to single rate flat demand charges for the three General Service rate class segments is similar to the 3 tier approach used for the combined General Service rate class, except for the stacking of the tiers instead of the independent levels for each rate class.

69.3. Please confirm that as the size of the electricity demand requirements increase for BC Hydro's customers the issues of the efficiency of use of investment in the infrastructure to serve the demand becomes more critical to both BC Hydro and the customers in terms of opportunity to cost-effectively reduce the costs of service, providing a logic for explicit alignment of demand recovery more closely with cost causation.

70. Reference: Exhibit B-1, Page 6-58 & 6-59

Figure 6-10 F2017 Bill Impacts less RRA for LGS Flat Energy and Flat Demand, Demand Cost Recovery = ~50 Per Cent

Annual Consumption kWh

Highest kW

Load Factor

	200,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	-10.9%	-12.8%	-13.5%	-13.8%	-14.0%	-14.1%	-14.2%	-14.2%	-14.3%	-14.3%	-14.4%	-14.4%	-14.4%	-14.4%	-14.5%	-14.5%	-14.5%
20%	-11.4%	-6.1%	[illegible]	[illegible]	[illegible]	-6.2%	-6.3%	-6.4%	-6.5%	-6.6%	-6.6%	-6.7%	-6.7%	-6.8%	-6.8%	-6.8%	-6.8%
30%	-12.0%	-3.5%	-2.9%	-3.0%	-4.0%	-4.1%	-4.5%	-4.6%	-4.7%	-4.8%	-4.9%	-4.9%	-5.0%	-5.0%	-5.1%	-5.1%	-5.1%
40%	-12.0%	-4.7%	-0.5%	-0.7%	-1.2%	-1.5%	[illegible]	-1.9%	-2.0%	-2.1%	-2.2%	-2.3%	-2.3%	-2.4%	-2.4%	-2.5%	-2.5%
50%	-14.9%	-7.1%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-1.1%	0.0%	-0.1%	-0.2%	-0.3%	-0.4%	-0.4%	-0.5%	-0.5%	-0.6%
60%	-16.8%	-8.8%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
70%	-18.8%	-10.1%	-2.2%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
80%	-20.8%	-11.1%	-4.2%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
90%	-21.9%	-11.9%	-5.8%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Lowest kW

Red font indicates bill impact higher than RRA

Oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load factor.

Figure 6-11 F2017 Bill Impacts less RRA for LGS Flat Energy and Flat Demand, Demand Cost Recovery = ~65 Per Cent

Annual Consumption kWh

Highest kW

Load Factor

	200,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	-2.5%	-2.7%	-2.4%	-2.7%	-2.9%	-3.1%	-3.2%	-3.2%	-3.3%	-3.3%	-3.4%	-3.4%	-3.4%	-3.4%	-3.5%	-3.5%	-3.5%
20%	-4.3%	[illegible]	[illegible]	[illegible]	[illegible]	-1.3%	-1.5%	-1.6%	-1.7%	-1.8%	-1.8%	-1.9%	-1.9%	-1.9%	-2.0%	-2.0%	-2.0%
30%	-14.5%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-0.4%	-0.5%	-0.6%	-0.7%	-0.8%	-0.9%	-0.9%	-1.0%	-1.0%	-1.0%	-1.1%
40%	-20.2%	-2.6%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-0.1%	-0.2%	-0.2%	-0.3%	-0.3%	-0.3%	-0.4%
50%	-24.0%	-4.5%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
60%	-26.7%	-6.3%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
70%	-29.2%	-11.8%	-3.5%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
80%	-31.8%	-13.9%	-5.2%	-0.7%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
90%	-33.2%	-14.2%	-6.6%	-2.0%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Lowest kW

Red font indicates bill impact higher than RRA

Oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load factor.

70.1. Please confirm that data above shows significant mitigation of the alignment of load factor cost causation with the demand charge recovery of costs, leading to a fairer rate structure proposal based on Bonbright's principles.

71. Reference: Exhibit B-1, Page 6-63

Table 6-20 LGS Rate estimates given rate structure transition in F2017

LGS	F2016	F2017 Status Quo	F2017 BC Hydro Proposal (65% Demand Recovery)	F2017 Sensitivity (50% Demand Recovery)
Basic cents/day	22.57	23.47	23.47	23.47
Demand $/kW				
T1			10.83 Flat	8.35 Flat
T2	5.50	5.72		
T3	10.55	10.97		
Energy cents/kwh				
T1	10.66	11.17	5.37 Flat	5.98 Flat
T2	5.13	5.37		
Part 2	9.90	10.10		
Minimum	3.30	3.43		

71.1. Please confirm that the Energy Flat rate is well below the LRMC for new energy supply presenting an opportunity to determine whether or not there are more effective means for incenting conservation and efficiency for this heterogeneous rate classes such as LGS.

71.2. Please confirm that BC Hydro will be open in Module 2 to exploring alternatives to see if any may more effectively incent conservation and efficiency than rate structures are likely to accomplish.

72. Reference: Exhibit B-1, Page 6-68

A three-year phase-in period for BC Hydro's preferred MGS rate (F2017-F2019) would have only minor mitigation of bill impacts as compared to no phase-in (i.e., one-time F2018 implementation) impacts:

- Under a three-year phase-in, customers who experience adverse bill impacts greater than 10 per cent are limited to about 800 accounts with less than about 40 MWh/year of annual consumption; and

72.1. Please provide the percentage of accounts for MGS which 800 accounts represents and the percentage of energy consumption for MGS that 40 MWh/year represents.

72.2. Please confirm that the adverse bill impact in the case of MGS customers, which might cause one to look at options to phase-in the changes is in fact redressing a long standing under collection from these customers relative to cost causation principles.

73. Reference: Exhibit B-1, Page 6-72

- There would be no need for TS 82. Refer to section 6.7.1;
- There would be no need for the existing LGS and MGS control groups used to help evaluate the conservation effects of the existing MGS and LGS rates. Refer to section 6.7.2;
- There would be no need for RS 26xx which exempts Corix from the LGS two-part rate. See section 6.7.3.

73.1. Please confirm that there are no negative consequences anticipated in regard to eliminating these three provisions, where the proposed rate design has eliminated the need for the provision.

F. Chapter 7 – Transmission Service Rate Design

74. Reference: Exhibit B-1, Page 7-9 & 7-13

14 Tier 2 within the range of LRMC (with inflation). Option 1 is not forecast revenue
15 neutral in F2017 since the bill neutrality definition of revenue neutrality is used
16 to determine the Tier 1 rate once the Tier 2 rate is increased by an amount
17 greater than the RRA rate increase so that it is at the lower end of the LRMC
18 range. Since in F2018 and F2019 the RRA rate increases are applied to the
19 Tier 1 and Tier 2 rates equally, Option 1 is forecast revenue neutral in F2018
20 and F2019 as well as customer bill neutral. Option 1 prioritizes the Bonbright
8 The bill neutrality definition of revenue neutrality is unique to RS 1823. The RIB,
9 LGS, MGS and SGS rates are all determined on a forecast revenue neutrality basis.
10 This means that the calculated RIB, LGS, MGS and SGS rates collect the same
11 revenue as the target revenue in each rate class by design and on a forecast basis.

12 BC Hydro reviewed the revenue impacts associated with the three pricing principle
13 options relative to forecast revenue neutrality in Attachment 4 to the Workshop 5
14 consideration memo:

15 • Option 1 under-recovers revenue in F2017 by $2.2 million;[262]

74.1. Please discuss whether or not an application of a rate increase, which is not forecast revenue neutral, is effectively creating a rebalancing in contravention of the LGIC direction or does it just create an under collection of the revenue requirement for the F2017 year.

74.2. Please describe the impact on all customer group RC ratios as a consequence of implementing a non-forecast revenue neutral approach as opposed to implementing a forecast revenue neutral approach for the transmission rate.

75. Reference: Exhibit B-1, Page 7-20

17 Aside from COPE 378 (at Workshop 10), no stakeholder providing feedback on this
18 topic supported BC Hydro pursuing a reconfigured RS 1825. AMPC and its
19 members favoured BC Hydro focusing on the freshet rate pilot (and load curtailment
20 pilot). AMPC reasoned that overall complexity, low margins, price risk and the
21 current three-year commitment requirement combine to make RS 1825 less
22 attractive to Transmission Service customers than RS 1823. AMPC's feedback is
23 consistent with the feedback received at the May to June 2014 regional sessions
24 with Transmission Service customers outlined in section 2.2.3.4 of the Application, at
25 which a majority of Transmission Service customers indicated that TOU rates would
26 not work for their businesses since they operate a continuous manufacturing

75.1. In the event that new Transmission Service customers were to locate in the province and had a load profile and process capability, which enabled switching its process between requiring electricity and being 'self-sufficient' would BC Hydro reconsider its position on this rate.

75.2. In the event that such a new Transmission Service customer came to BC would BC Hydro be able to react and put such a rate in place to facilitate a mutually favourable opportunity for the new business.

76. Reference: Exhibit B-1, Page 7-22

- CEC suggested RS 1852 should be retained but refined to better match BC Hydro's system demand issues. BC Hydro agrees with the suggestion. RS 1852 was originally designed around Vancouver Island's unique 'two peak' system load (6 a.m. to 10 a.m. and 4 p.m. to 8 p.m.). However, as demonstrated in section 4.2 of the Consideration Memo, the South Peace region does not have a two peak system load. Areas that may be transmission constrained in the future include the Lower Mainland (depending on the number of LNG proposals that proceed) and the North Coast/Prince Rupert region. Accordingly, BC Hydro prefers to have discretion to determine the HLH period(s) that will apply based on customer location/region because transmission constraints change over time and by location.

76.1. Please discuss when refinement of 1852 might be undertaken and whether or not this is a likely candidate for Module 2.

77. Reference: Exhibit B-1, Page 7-26

BC Hydro seeks approval of the freshet rate no later than February 1, 2016 as a two-year pilot to run between the May to July 2016 and May to July 2017 freshet periods.

77.1. Is it possible that for a company to make good economic use of such a rate it may need to have the potential for a longer term pilot?

77.2. Would BC Hydro be open to retaining some flexibility with regard to the length of time and perhaps some other terms with respect to this pilot in order to ensure that it has the ability to work with customers to optimize the potential from such a rate.

78. Reference: Exhibit B-1, Page 7-26 & 7-27

As discussed in sections 1.1.3 and 7.1 of the Application, BC Hydro is proposing to create a new optional rate (RS 1892) for non-firm service during these freshet periods. RS 1892 would be available to customers taking service under RS 1823.

support to further develop the rate. BC Hydro noted on page 21 of the Workshop 10 consideration memo that "stakeholders agree there may be merit in a freshet rate including representatives of BC Hydro's residential, General Service and Transmission Service customers".

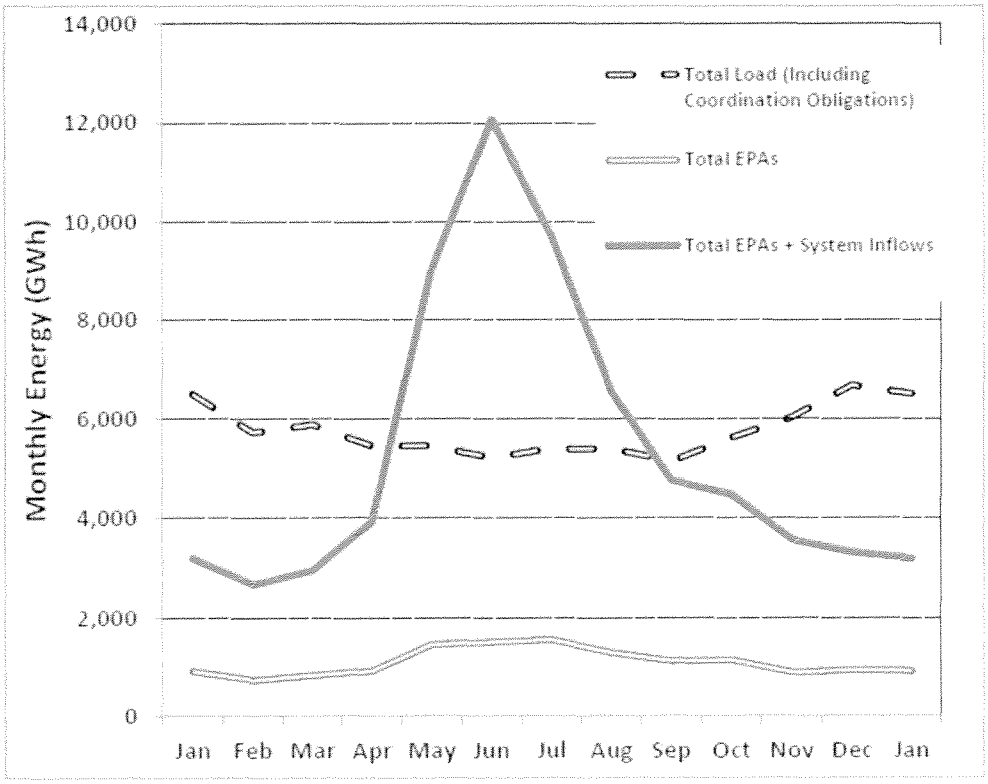
78.1. Please explain whether or not BC Hydro considered making the freshet pilot available to general service rate class customers who might be able to complement BC Hydro's system advantages in offering a freshet rate and if not why not.

78.2. Is BC Hydro aware that some general service rate class customers would be interested in such a rate and could usefully increase productivity in their businesses with access to such rates?

78.3. Will Module 2 enable discussion of interruptible non-firm rates for general service rate classes and will the freshet economic become a part of the considerations in setting such rates that would become accessible to general service customers?

79. Reference: Exhibit B-1, Page 7-28

Figure 7-2 System Inflows

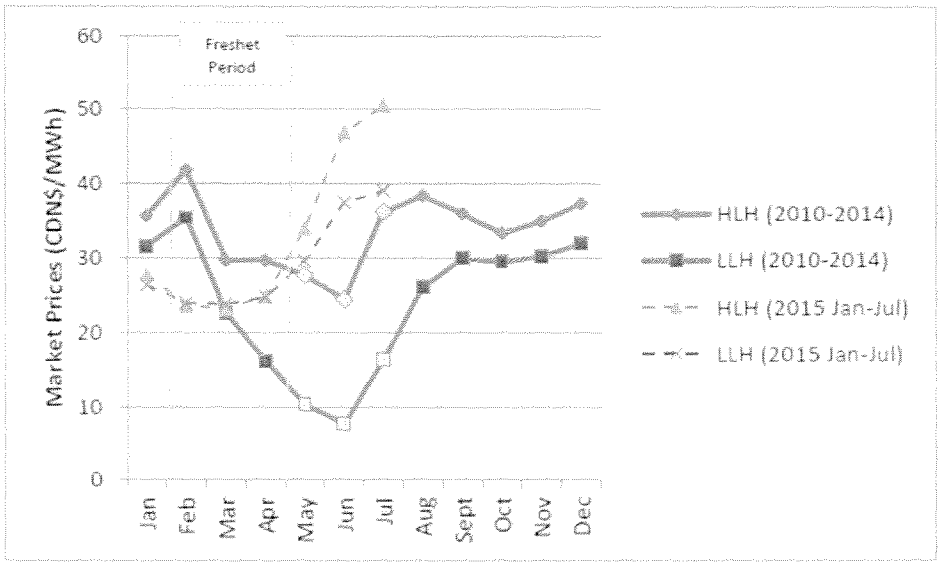


79.1. Please confirm that to absorb 1000 GWh during the freshet time frame would require over 1300 MW of load for the period.

79.2. What is the maximum amount of energy BC Hydro would find useful to absorb during this time period in order to optimize its system, including optimization in terms of taking advantage of the Mid-C markets?

80. Reference: Exhibit B-1, Page7-30

Figure 7-3 Five-Year Average of Mid-C Market Prices (2010 – 2014) – Updated with 2015 Prices to the End of July



80.1. Given that the low prices at Mid C appear to be available from March through to August and that in some years the freshet impact on prices may occur early would it not make sense for the freshet rate to be available on a more flexible basis responding to market and system conditions?

81. Reference: Exhibit B-1, 7-38

BC Hydro considers a proxy wheeling fee of $CDN 3/MWh appropriate given the cost rationale and the fact there are risks to non-participating customers. This proposed fee is approximately 50 per cent of the BPA wheeling fee that BC Hydro proposed at Workshop 10.

81.1. Please confirm that taking advantage of the freshet period is possible because of the investment in the BC Hydro electrical system, which is being paid for by BC Hydro's core customers.

81.2. Please discuss why a normal as opposed to a 50% wheeling fee would not be appropriate.

82. Reference: Exhibit B-1, 7-40

consideration memo.[283] The benefits to participating customers relate to the price spread between the RS 1823 Tier 1 rate and Mid-C prices (discussed in section 7.3.4.2) while the benefits to non-participating customers relate to the price floor and wheeling fee (discussed in section 7.3.4.3 under the heading "Energy Charge"). BC Hydro acknowledges the rate could bring other benefits to both groups, but these have not been quantified.

82.1. Please confirm that this discussion is just the energy benefit and that because it would be treated as non-firm there would also be a benefit of no additional demand charges for the customer.

G. Chapter 8 – Electric Tariff Terms and Conditions

83. Reference: Exhibit B-1, page 8-10 and Exhibit G-1B

- Labour for customer service and credit agents to review files and issue the disconnection order;
- Labour for customer service or credit agents to issue a reconnection order following the reporting of a payment, for customers not electing or able to report a payment and initiate the reconnection using self-service tools; and
- Direct labour costs to manually disconnect or reconnect a service, for the proportion of disconnections and reconnections that cannot be performed remotely.

The default Minimum Reconnection Charge is applicable for any remote reconnection, as well as when a manual reconnection is performed during regular working hours. When a manual reconnection is requested by the customer outside of regular working hours, and if a crew is available to be dispatched, the overtime Minimum Reconnection Charge will apply to recover the additional costs. BC Hydro proposes to update the overtime Minimum Reconnection Charge from $158 to $280 to recover increased costs associated with a manual reconnection done on overtime hours. After-hour reconnections at call-out rates are extremely rare and so it is

Minimum Reconnection Charges

Based on the weighted average cost of service of the F2015 manual and remote reconnections.

Costs	Regular Hours	Overtime – Manual	Call Out
ABSBC (Call Centre and Credit Review)	$5.37	$5.37	
Manual Disconnection (5%)	$9.48	$9.48	
Manual Reconnection (7% for regular hours / 100% for Overtime)	$14.95	$265.47	
Total Costs	$29.80	$280.32	
Rounded Minimum Reconnection Charges	**$30**	**$280**	**Remove**

83.1. Please clarify the activities and time elements that are included in Manual Disconnection cost of $9.48, and the reference to the 5%.
83.2. Please clarify the activities and the time elements that are included in the Manual Reconnection, and the reference to the 7% for regular hours, and 100% for overtime.
83.3. Please provide a breakdown of the costs for customer service for customers not electing or able to report a payment and initiate the reconnection service using self-service tools.
83.4. What are the direct labour costs to manually disconnect or reconnect a service?
83.5. What is an approximate proportion of disconnections and reconnections that cannot be performed remotely?

84. Reference: Exhibit B-1, page 8-8 and page 8-10

Minimum Reconnection Charge (default) – remote and manual reconnections during regular working hours and remote reconnections outside of regular working hours	30 per meter
Manual reconnection performed on overtime	280 per meter

The default Minimum Reconnection Charge is applicable for any remote reconnection, as well as when a manual reconnection is performed during regular working hours. When a manual reconnection is requested by the customer outside of regular working hours, and if a crew is available to be dispatched, the overtime Minimum Reconnection Charge will apply to recover the additional costs. BC Hydro proposes to update the overtime Minimum Reconnection Charge from $158 to $280 to recover increased costs associated with a manual reconnection done on overtime hours. After-hour reconnections at call-out rates are extremely rare and so it is

84.1. Please explain the difference between a call-out and a manual reconnection outside of regular working hours.
84.2. What is the overtime rate that is used to cost out the manual reconnection performed on overtime?
84.3. What factors contributed to the overtime rate increasing by over $120?

85. Reference: Exhibit B-1, page 8-14 and Appendix G-1B

The current Standard Charges in section 11.3 of the Electric Tariff include a "Returned Cheque or Pre-Authorized Payment Charge" for when a customer makes a payment but it is rejected for a reason such as insufficient funds. Currently, this charge is linked to the NSF fee posted by BC Hydro's banking provider, BMO Bank of Montreal. Although BC Hydro's standard charge for a returned payment has remained at $20, the posted NSF fee has been raised several times since the 2007 RDA and is currently $40.

Miscellaneous Charges: Returned Payment Charge

Based on BC Hydro's F2015 weighted average costs of handling returned cheques and returned electronic fund transfers (EFT):

Returned Payments in F2015	
Returned Cheques	1,045
Returned EFTs	10,847
Total Returned Payments	11,892
Bank of Montreal (BMO) and Symcor charges	
Weighted average per returned payment	$1.37
ABSBC Handling Cost	
Cost per returned payment	$3.68
Customer Communication (Letter)	$1.00
Total cost of handling a returned payment	$6.05
Rounded	**$6**

85.1. Please provide the cost of a returned Electronic Funds transfer.

85.2. Please provide examples of what would represent appropriate charges if returned payment charges for cheques had a different fee (based on costs) than those for electronic funds transfers.

86. Reference: Exhibit B-1, page 8-16 and 8-17

In accordance with section 4.3 of the Electric Tariff, a customer that doubts the accuracy of the meter may have the meter tested by Measurement Canada.[299] There is no charge to the customer if the meter is found to be operating outside of normal parameters as described within the *Electricity and Gas Inspection Act*;[300] however in accordance with section 6.7 of the Electric Tariff, the customer is currently charged the default Minimum Reconnection Charge (currently $125) if the meter is deemed to be accurate.

option 1 - the updated default Minimum Reconnection Charge of $30; option 2 – the updated Minimum Connection Charge (First Meter) of $181 to more closely reflect cost recovery; and option 3 – the current (not updated) default Minimum Reconnection Charge of $125. No stakeholder supported option 1, but stakeholders were divided as to whether option 2 or option 3 was the best option. COPE 378 expressed concern that both option 2 and option 3 may result in some customers with legitimate concerns foregoing their right to have the meter tested out of concern they would be charged if the meter passes.

86.1. Is it possible for there to be a problem related to the meter installation such as it recording the wrong unit in a multi-family dwelling or other issue such that the meter operates correctly but the record is incorrect?

86.1.1. If yes, has BC Hydro experienced any situations of this nature? Please explain.

86.2. Do customers have the opportunity to discuss their concerns with a BC Hydro representative and have assistance resolving their concerns? Please explain.

86.3. Could a BC Hydro representative waive the fee if they accepted the customer's concerns as indicating a potential problem but the customer was concerned about the potential cost of testing? Please explain.

86.4. Is the customer required to pay the charge up front, and receive a reimbursement if the meter does not perform properly under testing?

87. Reference: Exhibit B-1, page 8-23

- Billing errors – If the electric utility erred and overcharged the low income customer, it will refund the money immediately;

87.1. Can non low-income customers receive an immediate refund if the electric utility erred and overcharged them?

87.1.1. If not, please explain why not.

87.1.2. If not, does BC Hydro pay interest at the same rate as that collected for non-payment? Please explain.

1.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-4 and 2-5

BC Hydro's view is that these British Columbia's energy objectives are not legally binding on the Commission for rate design purposes:

- Subsections 44.2(5.1)(a), 46(3.3)(a) and 71(2.21)(a) of the *UCA* expressly provide that the Commission "must consider and be guided by … [the] British Columbia's energy objectives" for purposes of adjudicating BC Hydro's DSM expenditure schedules, Certificate of Public Convenience and Necessity applications and those Electricity Purchase Agreement (**EPA**) filings subject to a hearing;

- There is no corresponding requirement set out in sections 58 to 61 of the *UCA*, which contain the rate setting provisions.

The net result in BC Hydro's view is that the Commission <u>may,</u> but is not obliged to, consider and be guided by the British Columbia's energy objectives, subject to the proviso that in the event of a conflict between an energy objective and a rate-setting provision of the *UCA*, the latter must prevail.

1.1.1 Are there any instances in this Application in which BC Hydro identifies a conflict between an energy objective and a rate-setting provision of the UCA?

RESPONSE:

In BC Hydro's view, none of the rate design proposals contained in 2015 RDA Module 1 conflict with the section 2 *CEA* British Columbia's energy objectives. Please refer to BC Hydro's responses to BCUC IRs 1.2.1, 1.2.2 and 1.2.3.

1.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-4 and 2-5

BC Hydro's view is that these British Columbia's energy objectives are not legally binding on the Commission for rate design purposes:

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1.1.1 Are there any instances in this Application in which BC Hydro identifies a conflict between an energy objective and a rate-setting provision of the UCA?

1.1.1.1 If yes, please identify those instances and explain why there is a conflict.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.1.1.

1.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-4 and 2-5

BC Hydro's view is that these British Columbia's energy objectives are not legally binding on the Commission for rate design purposes:

- Subsections 44.2(5.1)(a), 46(3.3)(a) and 71(2.21)(a) of the *UCA* expressly provide that the Commission "must consider and be guided by … [the] British Columbia's energy objectives" for purposes of adjudicating BC Hydro's DSM expenditure schedules, Certificate of Public Convenience and Necessity applications and those Electricity Purchase Agreement (**EPA**) filings subject to a hearing;
- There is no corresponding requirement set out in sections 58 to 61 of the *UCA*, which contain the rate setting provisions.

The net result in BC Hydro's view is that the Commission <u>may,</u> but is not obliged to, consider and be guided by the British Columbia's energy objectives, subject to the proviso that in the event of a conflict between an energy objective and a rate-setting provision of the *UCA*, the latter must prevail.

1.1.2 What, if any, instances have occurred for BC Hydro in the last 5 years in which there has been a conflict between the energy objectives of the province, and the rate-setting provisions of the UCA? Please explain.

RESPONSE:

By definition any BC Hydro rates that the Commission set between 2010 and September 2015 are fair, just and not unduly discriminatory.

As noted in BC Hydro's response to CEC IR 1.1.1, in BC Hydro's view, none of the rate design proposals contained in 2015 RDA Module 1 conflict with the section 2 *CEA* British Columbia's energy objectives. Please also refer to BC Hydro's response to BCUC IRs 1.2.1, 1.2.2 and 1.2.3.

2.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-8

> ***2.2.1.4 Special Direction No. 10***
>
> The 2012 amendments to Special Direction No. 10 to the Commission[43] (**SD 10**) are relevant to the discussion of the lower energy LRMC in section 2.3.2.2 below. Sections 1 and 3 of SD 10 provide that the Commission, in setting rates for BC Hydro, must use the planning criterion of average water. As detailed in footnote 15 in Chapter 1 in respect of the Electricity Self-Sufficiency Regulation, the 2012 change in planning criterion increases the combined reliance on BC Hydro's Heritage hydroelectric system non-firm energy backed by market reliance in F2017 by about 4,100 GWh/year, reducing the need for new energy resources.

1.2.1 Does BC Hydro anticipate changes to the Average Water determination over the next 10 years as a result of climate change? Please explain.

RESPONSE:

BC Hydro does not anticipate a change to the Average Water determination over the next ten years as a result of climate change. A number of studies have been conducted which look at both the historical and future impacts of climate change on water availability in watersheds managed by BC Hydro. Historical trends in annual inflows into BC Hydro reservoirs have not been statistically significant. Climate change projections for several BC Hydro watersheds suggest only a modest increase in annual water availability for the 2050s (2041 to 2070), which is much beyond the next ten-years' timeframe. The results of these climate change impact-related studies are summarized in Appendix 2C and section 2.3.1.7 of the 2013 IRP; https://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/november-2013-irp.html.

2.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-8

2.2.1.4 Special Direction No. 10

The 2012 amendments to Special Direction No. 10 to the Commission[43] (**SD 10**) are relevant to the discussion of the lower energy LRMC in section 2.3.2.2 below. Sections 1 and 3 of SD 10 provide that the Commission, in setting rates for BC Hydro, must use the planning criterion of average water. As detailed in footnote 15 in Chapter 1 in respect of the Electricity Self-Sufficiency Regulation, the 2012 change in planning criterion increases the combined reliance on BC Hydro's Heritage hydroelectric system non-firm energy backed by market reliance in F2017 by about 4,100 GWh/year, reducing the need for new energy resources.

1.2.1 Does BC Hydro anticipate changes to the Average Water determination over the next 10 years as a result of climate change? Please explain.

1.2.1.1 If yes, please discuss the changes that BC Hydro anticipates to the Average Water and how it would be accounted for in the current rate-setting process.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.2.1.

3.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-14 and page 2-15

At Workshop 8a, BC Hydro set out its position that Policy Action No. 4 of the 2007 Energy Plan does not oblige the Commission to ignore the eight Bonbright rate design criteria in favour of a conservation objective or to prioritize the Bonbright efficiency criterion over the other seven criteria. BC Hydro implemented an inclining

1. Price signals that encourage efficient use and discourage inefficient use	Economic Efficiency	Energy LRMC reference; energy conservation (total GWh).
4. Customer understanding and acceptance, practical and cost effective to implement	Practicality	BC Hydro and stakeholder opinion with BC Hydro giving greater weighting to the views of customers taking service under the particular rate structure being assessed unless there are cost implications for other customer classes; Maximum and customer bill impact (%, including the 10% bill impact test); One-time implementation and sustaining costs (quantified if possible, qualitative ranking otherwise); Jurisdictional references provided the different legal and regulatory regimes, and customer characteristics, are taken into account (refer to section 2.4.2 below).
5. Freedom from controversies as to proper interpretation	Practicality	Proposed measurement is the same as for Bonbright criteria (4).

1.3.1 Does item 4 'customer understanding and acceptance, practical and cost-effective to implement' apply to item 1 'price signals that encourage efficient use and discourage inefficient use', so that it incorporates the concept of customers being able to explicitly recognize and respond to price signals, and is not just a separate and generic understanding and acceptance of the tariff rates?

RESPONSE:

Yes. Price signals that are intended to encourage efficient use should be evaluated using the customer understanding lens. A rate structure that is too complex for customers to act on would not be consistent with the customer understanding and acceptance criterion.

3.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-14 and page 2-15

At Workshop 8a, BC Hydro set out its position that Policy Action No. 4 of the 2007 Energy Plan does not oblige the Commission to ignore the eight Bonbright rate design criteria in favour of a conservation objective or to prioritize the Bonbright efficiency criterion over the other seven criteria. BC Hydro implemented an inclining

1. Price signals that encourage efficient use and discourage inefficient use	Economic Efficiency	Energy LRMC reference; energy conservation (total GWh).
4. Customer understanding and acceptance, practical and cost effective to implement	Practicality	BC Hydro and stakeholder opinion with BC Hydro giving greater weighting to the views of customers taking service under the particular rate structure being assessed unless there are cost implications for other customer classes; Maximum and customer bill impact (%, including the 10% bill impact test); One-time implementation and sustaining costs (quantified if possible, qualitative ranking otherwise); Jurisdictional references provided the different legal and regulatory regimes, and customer characteristics, are taken into account (refer to section 2.4.2 below).
5. Freedom from controversies as to proper interpretation	Practicality	Proposed measurement is the same as for Bonbright criteria (4).

1.3.2 If not, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.3.1.

4.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-30 and 2-31 and Appendix C-1A(708/4902)

- BC Hydro grounded the 1991 RDA on four policy objectives, including that no customer bills should increase by more than 10 per cent. The 10 per cent level was a guideline. Reference was also made to a 'two-times rule' which states that if as a result of rate design bills were to increase by more than double the increase received on average by bills within the rate class, this would begin to encroach on the realm of rate shock. The Commission accepted that in the circumstances of the 1991 RDA the two-times rule could be used as a "rough guideline", noting that it appeared to give BC Hydro more flexibility within the context of a potential 7 per cent revenue requirements increase.[66]

BC Hydro proposals related to RIB: Maintain 2013 Residential Inclining Block (RIB) approach - Maximum of 10% bill impact, representing all-in costs (consisting of RRA rate caps + DARR + rate changes due to rate rebalancing + rate changes due to rate design), to single most adversely impacted customer – to be used as a limit for modelling purposes	□	□	x	□	*The 2015 RDA is an opportunity for a broader consideration of how rates in all customer classes can be structured to promote economic efficiency, appropriately share in the benefits of low cost heritage supply and protect households and business from well-defined rate shock thresholds or criteria.*

1.4.1 Please provide BC Hydro's views of the 'well-defined rate shock thresholds or criteria'.

RESPONSE:

COPE 378's written feed-back concerning Workshop 1, which is included in the preamble to CEC's IR, asserts there are "well-defined rate shock thresholds or criteria"(refer to the Workshop 1 consideration memo, Exhibit B-1, Appendix C-1A, page 236 of 280).

BC Hydro does not agree with COPE 378's assertion. The following summarizes some previous decisions of the Commission and other regulators on this topic which BC Hydro canvassed for purposes of the Commission's 2008 RIB rate proceeding. As is apparent from the following, there is no consistent objective measure of 'rate shock', and there exists a broad range of circumstances that will justify a rate change even where there is 'rate shock'.

BCUC

- **The Commission has allowed rate increases for residential customers as high as 33 per cent (where increasing commodity costs are the cause of the rate increase), and has allowed significant natural gas rate increases exceeding 20 per cent;[1]**

- **The Commission has allowed rate increases of 19 per cent for commercial customers and 15 per cent for residential customers, to reflect increased commodity costs, on the basis of an Inquiry Report that expressly allowed for further (additive) rate-design induced bill increases.[2]**

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[1] ***An Application by BC Gas Utility Ltd. for Approval of Rate Changes effective July 1, 2000* (June 21, 2000), Commission Order No. G-62-00. See also Commission Order Nos G-39-08 and G-95-08 which, when combined, raised Fort Nelson service area rates from $6.868/GJ to $10.151/GJ over two quarters, a 47.8 per cent increase. Also see Commission Order No. G-92-08 which raised Revelstoke service area propane rates from $0.4260/L to 0.5172/L, a 21 per cent increase, and Commission Order Nos G-38-08 and G-94-08 which allowed consecutive rate increases of 11 per cent for the Lower Mainland, Inland and Columbia service areas, within a few months.**

[2] ***An Application by BC Gas Utility Ltd. And Complaints into Increased Propane Rates at Revelstoke, B.C.* (October 1996) Commission Order No. G-100-96.**

AUC

- **Generally the AUC has sought to keep class-average rate increases to 10 per cent per year, while allowing individual customer bills to increase by greater amounts, particularly where customers have ways to mitigate the rate increases;[3]**
- **The AUC has allowed rate riders as high as 25 per cent, despite causing 'rate shock', where doing so would avoid even more rate shock in future periods;[4]**
- **The AUC has allowed class average rate increases to exceed its 10 per cent guideline in circumstances where there has been a reasonable passage of time since the previous rate change.[5]**

MPUB

- **The MPUB stated that rate shock occurs at rate increases of 20 per cent in the context of water and sewer rates, and 10 per cent in the context of revenue requirement increases of gas and electricity rates, but nevertheless has approved natural gas average rate increases of 16.1 per cent for residential customers and between 16.8 per cent and 28.5 per cent for commercial customers, and has frequently approved water rate increases much higher than the 20 per cent threshold;[6]**

OEB

- **The OEB has approved natural gas rate increases of 22 per cent, despite the utility's admission that this increase was "approaching rate shock".[7]**

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[3] ***Transalta Utilities Corporation 1996 Electric Tariff Application – Phase II Refiling*** **(February 25, 2000), Decision 2000-11, page 32.**

[4] ***Transalta Utilities Corporation 1999/2000 Electric Tariff Application Interim Settlement of 2000 Deferral Accounts*** **(August 31, 2000), Decision 2000-60, page 21.**

[5] ***ATCO Pipelines Application for Realignment of Rates*** **(October 2007), Decision 2007-073, page 13.**

[6] ***The Town of Winnipeg Beach Water and Sewer Rates By-Law #10/2005*** **(December 14, 2005), page 4, Order No. 165-05;** ***Manitoba Hydro – Interim Rate Increase Effective March 1, 2007*** **(February 28, 2007), page 11, Order 20/07;** ***Centra Gas Manitoba Inc. 2007/08 and 2008/09 General Rate Application and Other Matters*** **(July 27, 2007), page 7, Order 99/07;** ***An Application by Centra Gas Manitoba Inc. for an Order Approving Interim Primary Gas Sales Rates to be Effective for All Gas Consumed On and After August 1, 2000*** **(July 31, 2000), page ii, Order 115/00;** ***The City of Winkler Application For Revised Water And Sewer Rates Pursuant To City By-Law No. 1829-05*** **(May 2, 2005), page 10, Order 62/05;** ***The Town of Niverville Revised Water Rates*** **(December 28, 2007), page 2, Order 166/07; and** ***The Town of Snow Lake Revised Water and Sewer Rates Effective July 1, 2007*** **(June 28, 2007), pages 2 and 19, Order 83/07.**

[7] ***An Application by Natural Resource Gas Limited, pursuant to section 36(1) of the Ontario Energy Board Act, 1998, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of October 1, 2006*** **(September 20, 2006), page 37, EB-2005-0544.**

4.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-30 and 2-31 and Appendix C-1A(708/4902)

- BC Hydro grounded the 1991 RDA on four policy objectives, including that no customer bills should increase by more than 10 per cent. The 10 per cent level was a guideline. Reference was also made to a 'two-times rule' which states that if as a result of rate design bills were to increase by more than double the increase received on average by bills within the rate class, this would begin to encroach on the realm of rate shock. The Commission accepted that in the circumstances of the 1991 RDA the two-times rule could be used as a "rough guideline", noting that it appeared to give BC Hydro more flexibility within the context of a potential 7 per cent revenue requirements increase.[66]

BC Hydro proposals related to RIB: Maintain 2013 Residential Inclining Block (RIB) approach - Maximum of 10% bill impact, representing all-in costs (consisting of RRA rate caps + DARR + rate changes due to rate rebalancing + rate changes due to rate design), to single most adversely impacted customer – to be used as a limit for modelling purposes	☐	☐	x	☐	*The 2015 RDA is an opportunity for a broader consideration of how rates in all customer classes can be structured to promote economic efficiency, appropriately share in the benefits of low cost heritage supply and protect households and business from well-defined rate shock thresholds or criteria.*

1.4.1 Please provide BC Hydro's views of the 'well-defined rate shock thresholds or criteria'.

1.4.1.1 Please discuss whether or not these criteria should be consistently applied across rate classes.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.4.1.

4.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-30 and 2-31 and Appendix C-1A(708/4902)

- BC Hydro grounded the 1991 RDA on four policy objectives, including that no customer bills should increase by more than 10 per cent. The 10 per cent level was a guideline. Reference was also made to a 'two-times rule' which states that if as a result of rate design bills were to increase by more than double the increase received on average by bills within the rate class, this would begin to encroach on the realm of rate shock. The Commission accepted that in the circumstances of the 1991 RDA the two-times rule could be used as a "rough guideline", noting that it appeared to give BC Hydro more flexibility within the context of a potential 7 per cent revenue requirements increase.[66]

BC Hydro proposals related to RIB: Maintain 2013 Residential Inclining Block (RIB) approach - Maximum of 10% bill impact, representing all-in costs (consisting of RRA rate caps + DARR + rate changes due to rate rebalancing + rate changes due to rate design), to single most adversely impacted customer – to be used as a limit for modelling purposes	☐	☐	x	☐	*The 2015 RDA is an opportunity for a broader consideration of how rates in all customer classes can be structured to promote economic efficiency, appropriately share in the benefits of low cost heritage supply and protect households and business from well-defined rate shock thresholds or criteria.*

1.4.2 Does avoiding 'rate shock' take any priority over any or all of the Bonbright's principles? Please explain.

RESPONSE:

As set out in BC Hydro's response to CEC IR 1.4.1, BC Hydro does not agree that there is a consistent objective measure of 'rate shock'.

For purposes of 2015 RDA Module 1, BC Hydro prioritized the Bonbright customer understanding and acceptance, rate stability and fair apportionment of costs among customers criteria. As noted in section 2.4.1.1 of Exhibit B-1, BC Hydro used a 10 per cent bill impact test inclusive of 'all-in' costs (consisting of RRA increases – the Direction No. 7 rate caps for F2017 to F2019) on average; the DARR; and changes due to rate design) as part of the Bonbright customer understanding and acceptance criterion. As is apparent from the 2015 RDA, where there are trade-offs BC Hydro placed great weight on incremental bill impacts. See, for example, BC Hydro's primary RIB rate pricing principle consideration, which is customer understanding and acceptance and in particular bill impacts (Exhibit B-1, page 5-40).

5.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-38

- E-Plus rates: BC Hydro proposed to phase-out E-Plus rates over a 10-year period from April 1, 2008 to March 31, 2018. The Commission denied BC Hydro's proposal. Pursuant to 2007 RDA Direction 14, BC Hydro was instructed to "pay more attention to the exercise of its rights under the [E-Plus] Rate Schedules and to invest the necessary time and resources to ensure that its E-Plus customers comply with the Special Conditions of the [E-Plus] Rate Schedules …". The Commission approved restricting the ability to transfer the E-Plus rate to a new customer by amending the Availability clause to state that the E-Plus rate is available "only in Premises where there has been no change in customer since April 1, 2008". Refer to section 5.3.2 of the Application for a description of how BC Hydro responded to 2007 RDA Direction 14 and for BC Hydro's proposal with respect to its E-Plus rates;

1.5.1 What was BC Hydro's rationale for phasing out the E –Plus rates in the 2007 RDA?

RESPONSE:

As set out in section 3.8 of the 2007 RDA, BC Hydro's rationale for proposing to phase-out the E-Plus rates over ten years included:

- **The E-Plus rates do not recover the cost of service, and this does not support the principle of fairness. Other customers within the associated rate classes subsidize E-Plus customers;**
- **In an environment of rising marginal energy costs, E-Plus rates do not align with the need to encourage conservation within B.C.; and**
- **Given the wording of Special Condition 1 of RS 1105, there is no practical way to interrupt E-Plus customers during the periods when BC Hydro's system is typically constrained. E-Plus customers have never been interrupted.**

5.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-38

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1.5.2 Do these reasons still exist or have circumstances altered since then? Please explain.

RESPONSE:

Yes, two of the reasons advanced in the 2007 RDA (described in BC Hydro's response to CEC IR 1.5.1) still exist:

- **First, as set out in Table 5-13 of Exhibit B-1, page 5-51, the R/C ratio to serve Residential E-Plus heating load is less than one under two alternative assumptions, demonstrating that the current Residential E-Plus rate does not recover the cost to serve the Residential E-Plus heating load; and**

- **Second, Residential E-Plus service still cannot be implemented in practice due to the limitation of Special Condition 1 of the RS 1105. For further discussion, please refer to pages 5-50 to 5-51 of Exhibit B-1 and to section 2.3.2 of the Workshop 9a/9b Discussion Guide at Appendix C-3B of Exhibit B-1.**

It is no longer the circumstance that BC Hydro is in an environment of rising marginal energy costs.

5.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-38

- E-Plus rates: BC Hydro proposed to phase-out E-Plus rates over a 10-year period from April 1, 2008 to March 31, 2018. The Commission denied BC Hydro's proposal. Pursuant to 2007 RDA Direction 14, BC Hydro was instructed to "pay more attention to the exercise of its rights under the [E-Plus] Rate Schedules and to invest the necessary time and resources to ensure that its E-Plus customers comply with the Special Conditions of the [E-Plus] Rate Schedules …". The Commission approved restricting the ability to transfer the E-Plus rate to a new customer by amending the Availability clause to state that the E-Plus rate is available "only in Premises where there has been no change in customer since April 1, 2008". Refer to section 5.3.2 of the Application for a description of how BC Hydro responded to 2007 RDA Direction 14 and for BC Hydro's proposal with respect to its E-Plus rates;

1.5.3 Please explain whether or not E-Plus rates could be considered similar but of course not the same as the proposed freshet rate.

RESPONSE:

Both the Residential E-Plus rate (RS 1105) and the proposed freshet rate pilot (RS 1892) are interruptible (non-firm) rates. However:

- **BC Hydro is proposing the freshet rate pilot to, among other things, assist in the management of the freshet oversupply in the BC Hydro system during the freshet period of May to July (Exhibit B-1, section 7.3.4.1); and**

- **The Residential E-Plus rate is not likely to assist BC Hydro with the freshet oversupply; the energy charge of 5.22 cents/kWh (F2016) applies year round, and is not discounted during the freshet period. BC Hydro also notes the following. There are currently no limits in RS 1105 on the period of interruption except for Special Condition 1 (described at Exhibit B-1, page 5-50, lines 3 to 8). As set out in BC Hydro's response to BCUC IR 1.43.1, BC Hydro proposes to limit Residential E-Plus interruption periods to October through April. These are the months of highest customer demand in BC Hydro's service area - November to February is the winter period, and October, March and April are the 'shoulder period' when customer demand can also be high. Interruptions would not occur in the other five months of the year.**

6.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-44 and 2-45

2.3.2.1 Smart Meter Infrastructure

BC Hydro's installation of smart meters is 99 per cent complete with over 1.9 million meters installed throughout BC Hydro's service area. The new metering system allowed BC Hydro to better understand the load characteristics of its distribution voltage customers and to more accurately allocate costs within the F2016 COS study described in Chapter 3 of the Application. For example, in the 2007 RDA BC Hydro's COS study relied on a load research sample of about 400 residential customers and about 1,100 commercial customers. The collection of this data was done annually, took several months to complete and was labor intensive. Because the sample was so small, the customer class profiles created were general, sample redesign was not financially feasible and sample bias could have been an issue.

With smart metering, BC Hydro has been able to analyze daily consumption patterns for each individual customer while using a sample of approximately 45,000 customers to analyze hourly load shapes and conduct more in-depth load research. The additional data from smart metering has increased the accuracy of BC Hydro's load profile information which is a key input into cost allocation with the F2016 COS study. With the capability to create almost on-demand detailed customer load profiles, COS analysis, rate design and peak load forecasting can be improved. Going forward, BC Hydro will be able to use smart metering information to measure losses on individual feeders and further improve the distribution loss assumptions that are used in the F2016 COS study and some rates within the Electric Tariff.

1.6.1 Please provide a high level overview of the changes that BC Hydro discovered using the improved accuracy from its Smart Meter Information and how this impacted its load profile.

RESPONSE:

Improved accuracy and confidence of rate class load profiles has resulted in more consistent R/C ratios year to year, as variations will be less influenced by the uncertainty of load research estimates from the smaller samples.

7.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-48 and 2-54

3,000 GWh/year. Even with this amount of LNG load, the need for such an acquisition process is not until F2032. As described further in this section, BC Hydro currently has sufficient alternative cost-effective B.C.-based resources to meet expected future energy needs without LNG demand by:

- Pursuing the DSM target (2013 IRP Recommended Action 1); and
- Undertaking IPP EPA renewals and Site C (2013 IRP Recommended Actions 4 and 6) as the main elements to fill the identified energy gap after pursuit of the DSM target.

BC Hydro estimates that LNG projects could add between about 800 GWh to 6,600 GWh/year of additional energy demand, corresponding to about 100 MW to 800 MW of additional peak demand. Supplying the low- to mid-range of LNG load (up to about 3,000 GWh/year) will not have a material impact on the energy LRMC because BC Hydro has enough energy resources to serve such LNG load with the pursuit of the cost-effective B.C.-based resources listed above. However, potential LNG load is one source of demand uncertainty and therefore LRMC uncertainty.

- Natural gas-fired simple-cycle gas turbine generators (**SCGTs**) with a UCC of $88/kW-year. In the case where the expected LNG load of 3,000 GWh/year materializes, there is a need for about 400 MW of new system generating capacity resources. The 2013 IRP identified SCGTs located on the north coast to meet this need because of additional reliability benefits in that region.

1.7.1 Please provide BC Hydro's directional understanding with respect to the impact of falling oil prices on the likely size and timing of the potential LNG load.

RESPONSE:

Response to be provided on January 12, 2016.

7.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-48 and 2-54

3,000 GWh/year. Even with this amount of LNG load, the need for such an acquisition process is not until F2032. As described further in this section, BC Hydro currently has sufficient alternative cost-effective B.C.-based resources to meet expected future energy needs without LNG demand by:

- Pursuing the DSM target (2013 IRP Recommended Action 1); and
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1.7.1.1 Does BC Hydro anticipate that 3,000 GWh/year will be the likely load?

RESPONSE:

Response to be provided on January 12, 2016.

7.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-48 and 2-54

3,000 GWh/year. Even with this amount of LNG load, the need for such an acquisition process is not until F2032. As described further in this section, BC Hydro currently has sufficient alternative cost-effective B.C.-based resources to meet expected future energy needs without LNG demand by:

- Pursuing the DSM target (2013 IRP Recommended Action 1); and
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BC Hydro estimates that LNG projects could add between about 800 GWh to 6,600 GWh/year of additional energy demand, corresponding to about 100 MW to 800 MW of additional peak demand. Supplying the low- to mid-range of LNG load (up to about 3,000 GWh/year) will not have a material impact on the energy LRMC because BC Hydro has enough energy resources to serve such LNG load with the pursuit of the cost-effective B.C.-based resources listed above. However, potential LNG load is one source of demand uncertainty and therefore LRMC uncertainty.

- Natural gas-fired simple-cycle gas turbine generators (**SCGTs**) with a UCC of $88/kW-year. In the case where the expected LNG load of 3,000 GWh/year materializes, there is a need for about 400 MW of new system generating capacity resources. The 2013 IRP identified SCGTs located on the north coast to meet this need because of additional reliability benefits in that region.

1.7.1.1 Does BC Hydro anticipate that 3,000 GWh/year will be the likely load?

1.7.1.1.1 If yes, please provide BC Hydro's views as to when this would materialize, and over what period of time it might be brought in.

RESPONSE:

Response to be provided on January 12, 2016.

7.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-48 and 2-54

3,000 GWh/year. Even with this amount of LNG load, the need for such an acquisition process is not until F2032. As described further in this section, BC Hydro currently has sufficient alternative cost-effective B.C.-based resources to meet expected future energy needs without LNG demand by:

- Pursuing the DSM target (2013 IRP Recommended Action 1); and
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BC Hydro estimates that LNG projects could add between about 800 GWh to 6,600 GWh/year of additional energy demand, corresponding to about 100 MW to 800 MW of additional peak demand. Supplying the low- to mid-range of LNG load (up to about 3,000 GWh/year) will not have a material impact on the energy LRMC because BC Hydro has enough energy resources to serve such LNG load with the pursuit of the cost-effective B.C.-based resources listed above. However, potential LNG load is one source of demand uncertainty and therefore LRMC uncertainty.

- Natural gas-fired simple-cycle gas turbine generators (**SCGTs**) with a UCC of $88/kW-year. In the case where the expected LNG load of 3,000 GWh/year materializes, there is a need for about 400 MW of new system generating capacity resources. The 2013 IRP identified SCGTs located on the north coast to meet this need because of additional reliability benefits in that region.

1.7.1.1 Does BC Hydro anticipate that 3,000 GWh/year will be the likely load?

1.7.1.1.2 If no, please describe and provide quantification of BC Hydro's expectation of the LNG load for BC over the next 10 years.

RESPONSE:

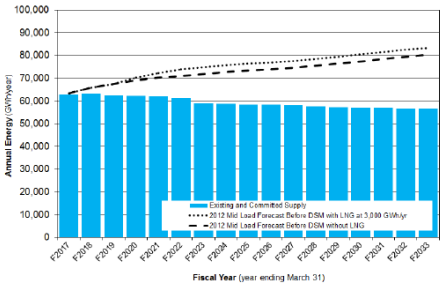
Response to be provided on January 12, 2016.

8.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-48 and 2-49

The 2013 IRP provides the analysis underpinning the energy LRB for BC Hydro's integrated system. A LRB is the difference between: (1) BC Hydro's annual load forecast, which projects BC Hydro customer demand over a 20-year period (in the case of the 2013 IRP this is the December 2012 Load Forecast) and (2) supply from existing and committed DSM and supply-side resources. There is a deficit or gap (i.e., a shortfall) if forecasted customer energy demand exceeds the existing and committed resources available to serve such load. Figure 2-1 is derived from the 2013 IRP and shows that there is a need for new energy resources beginning in F2017 without future DSM initiatives (including rate structures such as the RIB rate and RS 1823).

Figure 2-1 Energy LRB: Before Implementation of 2013 IRP Recommended Actions



The 2013 IRP proposes that BC Hydro meet the forecasted energy gap for the next 20 years predominantly by pursuing the DSM target, renewing some existing EPAs at the time they expire and Site C:

1.8.1 If BC Hydro expects that the LNG load will be significantly reduced, could an increase in DSM savings defer the need for future energy supply additions and or capacity additions? Please explain why or why not.

RESPONSE:

Response to be provided on January 12, 2016.

9.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-55

Several Workshop 3 participants advanced two grounds for including a generation capacity value in the energy LRMC for purposes of the RIB Step 2 rate: (1) the RIB rate contains no demand charge; and (2) while the RIB is an energy conservation rate, it delivers anticipated capacity savings. In section 4.1.2 of the Workshop 3 consideration memo (copy at Appendix C-3A), BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction. BC Hydro also referenced the 2011 RIB Re-Pricing Decision where the Commission stated that the RIB Step 2 rate should be based on a "price signal for customers to understand *what is happening to the cost of energy* they will consume in the future" [emphasis added].[101] Use of BC Hydro's energy LRMC for energy conservation rate structures such as the RIB rate is consistent with past Commission RIB decisions noted in section 2.3.1.6 above. However, to illustrate the impacts of the addition of a generation capacity value to the LRMC, BC Hydro included the upper end of the energy LRMC range with a generation capacity value (the Rev 6 UCC) in various figures in Chapter 5.

1.9.1 Please confirm that residential customers do not have a clear understanding of RIB pricing and conservation as it relates to peak capacity reduction or energy conservation.

RESPONSE:

BC Hydro confirms through the 2013 RIB Evaluation Report that a significant percentage of residential customers do have a good understanding of RIB rate pricing as it relates to energy conservation. This is documented in section 3.4.3 of the 2013 RIB Evaluation Report, through Tables 3.15 and 3.16 in particular, at Appendix C-3B of Exhibit B-1, pages 138 to 139 of 609.

BC Hydro has no recent, general population wide, representative surveys that specifically assessed Residential customer knowledge of RIB pricing as it relates to peak capacity reduction. The only related material is from the RIB evaluation survey, where customers were asked about their energy conservation behaviours. (Refer to Table 3.18 of the RIB Evaluation Report at Appendix C-3B of Exhibit B-1, page 141 of 609). RIB rate-aware customers were more likely to take action on a range of behaviours that would reduce peak capacity by reducing the winter heating load, for example by using a programmable thermostat or manually turning down the heat.

9.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-55

> Several Workshop 3 participants advanced two grounds for including a generation capacity value in the energy LRMC for purposes of the RIB Step 2 rate: (1) the RIB rate contains no demand charge; and (2) while the RIB is an energy conservation rate, it delivers anticipated capacity savings. In section 4.1.2 of the Workshop 3 consideration memo (copy at Appendix C-3A), BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction. BC Hydro also referenced the 2011 RIB Re-Pricing Decision where the Commission stated that the RIB Step 2 rate should be based on a "price signal for customers to understand *what is happening to the cost of energy* they will consume in the future" [emphasis added].[101] Use of BC Hydro's energy LRMC for energy conservation rate structures such as the RIB rate is consistent with past Commission RIB decisions noted in section 2.3.1.6 above. However, to illustrate the impacts of the addition of a generation capacity value to the LRMC, BC Hydro included the upper end of the energy LRMC range with a generation capacity value (the Rev 6 UCC) in various figures in Chapter 5.

1.9.2 Please confirm that increasing capacity ultimately has a bearing on the costs that customers will bear in the future to meet their energy needs?

RESPONSE:

Confirmed. Costs related to meeting customer-related capacity requirements, including approval by the BCUC where required, will be included in BC Hydro's revenue requirement and recovered through rates.

9.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-55

> Several Workshop 3 participants advanced two grounds for including a generation capacity value in the energy LRMC for purposes of the RIB Step 2 rate: (1) the RIB rate contains no demand charge; and (2) while the RIB is an energy conservation rate, it delivers anticipated capacity savings. In section 4.1.2 of the Workshop 3 consideration memo (copy at Appendix C-3A), BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction. BC Hydro also referenced the 2011 RIB Re-Pricing Decision where the Commission stated that the RIB Step 2 rate should be based on a "price signal for customers to understand *what is happening to the cost of energy* they will consume in the future" [emphasis added].[101] Use of BC Hydro's energy LRMC for energy conservation rate structures such as the RIB rate is consistent with past Commission RIB decisions noted in section 2.3.1.6 above. However, to illustrate the impacts of the addition of a generation capacity value to the LRMC, BC Hydro included the upper end of the energy LRMC range with a generation capacity value (the Rev 6 UCC) in various figures in Chapter 5.

1.9.2 Please confirm that increasing capacity ultimately has a bearing on the costs that customers will bear in the future to meet their energy needs?

1.9.2.1 If not confirmed, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.9.2.

9.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-55

> Several Workshop 3 participants advanced two grounds for including a generation capacity value in the energy LRMC for purposes of the RIB Step 2 rate: (1) the RIB rate contains no demand charge; and (2) while the RIB is an energy conservation rate, it delivers anticipated capacity savings. In section 4.1.2 of the Workshop 3 consideration memo (copy at Appendix C-3A), BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction. BC Hydro also referenced the 2011 RIB Re-Pricing Decision where the Commission stated that the RIB Step 2 rate should be based on a "price signal for customers to understand *what is happening to the cost of energy* they will consume in the future" [emphasis added].[101] Use of BC Hydro's energy LRMC for energy conservation rate structures such as the RIB rate is consistent with past Commission RIB decisions noted in section 2.3.1.6 above. However, to illustrate the impacts of the addition of a generation capacity value to the LRMC, BC Hydro included the upper end of the energy LRMC range with a generation capacity value (the Rev 6 UCC) in various figures in Chapter 5.

1.9.3 What is the total cost allocation for the class for each of energy, demand, and customer?

RESPONSE:

As provided in Appendix E of Exhibit B-1, Schedule 4.1 of the COS model shows that the Residential cost allocation of energy, demand and customer costs is $708.4 million, $1,060.6 million and $273.4 million.

9.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-55

> Several Workshop 3 participants advanced two grounds for including a generation capacity value in the energy LRMC for purposes of the RIB Step 2 rate: (1) the RIB rate contains no demand charge; and (2) while the RIB is an energy conservation rate, it delivers anticipated capacity savings. In section 4.1.2 of the Workshop 3 consideration memo (copy at Appendix C-3A), BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction. BC Hydro also referenced the 2011 RIB Re-Pricing Decision where the Commission stated that the RIB Step 2 rate should be based on a "price signal for customers to understand *what is happening to the cost of energy* they will consume in the future" [emphasis added].[101] Use of BC Hydro's energy LRMC for energy conservation rate structures such as the RIB rate is consistent with past Commission RIB decisions noted in section 2.3.1.6 above. However, to illustrate the impacts of the addition of a generation capacity value to the LRMC, BC Hydro included the upper end of the energy LRMC range with a generation capacity value (the Rev 6 UCC) in various figures in Chapter 5.

1.9.4 What is the proposed recovery in absolute dollars for the basic charge?

RESPONSE:

Proposed recoveries from the RIB rate basic charge are as follows, as reported in Appendix H-1A of Exhibit B-1, pages 7 to 9:

F2017: $118,165,255;

F2018: $124,614,514; and

F2019: $130,849,138.

9.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-55

> Several Workshop 3 participants advanced two grounds for including a generation capacity value in the energy LRMC for purposes of the RIB Step 2 rate: (1) the RIB rate contains no demand charge; and (2) while the RIB is an energy conservation rate, it delivers anticipated capacity savings. In section 4.1.2 of the Workshop 3 consideration memo (copy at Appendix C-3A), BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction. BC Hydro also referenced the 2011 RIB Re-Pricing Decision where the Commission stated that the RIB Step 2 rate should be based on a "price signal for customers to understand *what is happening to the cost of energy* they will consume in the future" [emphasis added].[101] Use of BC Hydro's energy LRMC for energy conservation rate structures such as the RIB rate is consistent with past Commission RIB decisions noted in section 2.3.1.6 above. However, to illustrate the impacts of the addition of a generation capacity value to the LRMC, BC Hydro included the upper end of the energy LRMC range with a generation capacity value (the Rev 6 UCC) in various figures in Chapter 5.

1.9.5 What is the proposed recovery for energy and demand from the energy revenues including Tier 1 and Tier 2?

RESPONSE:

The RIB rate energy charges recover 100 per cent of the energy and demand costs assigned to the Residential class.

Forecast energy revenues from Residential Step 1 and Step 2 energy rates are as follows, as reported in Appendix H-1A of Exhibit B-1, pages 7 to 9:

Forecast Energy Revenues	Step 1 Rate ($)	Step 2 Rate ($)
F2017	834,939,849	896,267,415
F2018	868,523,202	931,855,130
F2019	893,995,110	959,277,216

10.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-60

customers as to the price of acquiring marginal energy. Any lower price would incentivize inefficient electricity usage, and any higher price would discourage or unfairly penalize efficient usage. BC Hydro does not see a principled basis for setting the RIB Step 2 price without using LRMC as a referent. At Workshop 3 BC Hydro agreed with BCSEA that the pricing of the Step 2 rate in reference to the energy LRMC should not be regarded as a hard and fast rule. Refer to Attachment 1 (page 12) to the Workshop 9a/9b Consideration Memo (copy at Appendix C-3B of the Application); and to section 3.1.2 of the Workshop 3 Consideration Memo (copy at Appendix C-3A) for additional detail.

1.10.1 Please explain how a higher price discourages or 'unfairly penalizes' efficient usage?

RESPONSE:

A price that is higher and not reflective of LRMC provides an incentive for conservation actions and investments that are more costly to consumers (either in loss of utility or actual expenditures) than alternative supply options. In standard economic terms, a price above marginal cost reduces consumer surplus by an amount greater than the gain in producer surplus, resulting in a deadweight loss, which is the net cost to society due to the decision to not set prices equal to marginal cost.

10.0 A. Chapter 2 – Stakeholder Engagement and Rate Design Evaluation Methodology

Reference: Exhibit B-1, page 2-60

customers as to the price of acquiring marginal energy. Any lower price would incentivize inefficient electricity usage, and any higher price would discourage or unfairly penalize efficient usage. BC Hydro does not see a principled basis for setting the RIB Step 2 price without using LRMC as a referent. At Workshop 3 BC Hydro agreed with BCSEA that the pricing of the Step 2 rate in reference to the energy LRMC should not be regarded as a hard and fast rule. Refer to Attachment 1 (page 12) to the Workshop 9a/9b Consideration Memo (copy at Appendix C-3B of the Application); and to section 3.1.2 of the Workshop 3 Consideration Memo (copy at Appendix C-3A) for additional detail.

1.10.2 Who would be the beneficiary, if any, of an unfair penalty from a higher than LRMC price?

RESPONSE:

BC Hydro responds to this IR by way of a three-step residential rate example whereby a third step is deliberately set above and not reflective of LRMC. Under such a rate, low energy consumers benefit.

11.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-2

> BC Hydro would continue to submit Fully Allocated COS results with the Commission every year pursuant to 2007 RDA Direction 2. The Fully Allocated COS would reflect any Commission findings concerning the F2016 COS.

1.11.1 Please confirm that, because the LGIC has deferred the timing for rate rebalancing, the CEC has informed BC Hydro that it will not bring forward a COS expert to test the BC Hydro COS submissions for 2015 and that the CEC has requested, during consultation, that BC Hydro, for the proposed 2019 RDA which would include rate rebalancing, keep open the possibility that interveners be enabled to test the COS changes from 2007 RDA decision base forward to the 2019 RDA filing.

RESPONSE:

Confirmed.

11.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-2

> BC Hydro would continue to submit Fully Allocated COS results with the Commission every year pursuant to 2007 RDA Direction 2. The Fully Allocated COS would reflect any Commission findings concerning the F2016 COS.

1.11.2 Please confirm that BC Hydro has informed the CEC that it would have no problem with the 2015 COS being constrained in terms of precedent to the 2015 RDA and its purposes, provided that in further consultation with the CEC that BC Hydro would identify the key areas of concern where it would be appropriate to the carry forward the 2007 RDA decision base to enable testing of the changes through to the 2019 RDA.

RESPONSE:

As set out in Exhibits B-2 and B-3, BC Hydro proposes a NSP for the F2016 COS sometime after the January 12, 2016 procedural conference to determine if, as evidenced by the 2015 RDA stakeholder engagement process, there is general consensus on a number of F2016 COS methodology items that could be the subject of Commission endorsement for purposes of the F2019 COS.

BC Hydro foresees that for some COS methodology items the default will be the 2007 RDA Decision. The F2019 COS-related stakeholder engagement process would re-examine these default 2007 RDA Decision-related COS methodology items. For example, BC Hydro acknowledged in Exhibit B-3 that CEC expressed concern during the 2015 RDA stakeholder engagement process that it had not had an opportunity to examine in detail the F2016 COS approach to classifying and allocating Distribution costs.

11.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-2

> BC Hydro would continue to submit Fully Allocated COS results with the Commission every year pursuant to 2007 RDA Direction 2. The Fully Allocated COS would reflect any Commission findings concerning the F2016 COS.

1.11.3 Please confirm that this further consultation has not yet occurred but that BC Hydro will engage in the further consultation with the CEC to identify the key areas of concern and that this will be done in time to provide the outcome as a filing in this regulatory proceeding.

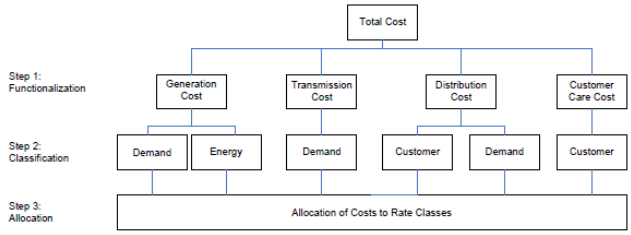
RESPONSE:

Prior to filing the F2019 COS, BC Hydro will engage CEC and other stakeholders in a timely manner to identify areas of concern and solicit feedback on BC Hydro's F2019 COS proposals.

12.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-4, Page 3-31

Figure 3-1 Cost Allocation Methodology



Note that Generation energy is adjusted for losses prior to allocation. Before the pro rata calculations are done, transmission and distribution losses of 6 per cent and 6 per cent respectively are added to the energy consumption of distribution customers while transmission losses of 6 per cent are added to the energy consumption of transmission voltage customers. These loss assumptions were reviewed as part of the 2007 RDA and BC Hydro continues to believe they are valid as discussed in section 3.8.2.1.

1.12.1 Please confirm that for the Figure 3-1 description of the methodology for cost of service allocations that the transmission and distribution systems do have energy components, which are not reflected for purposes of simplification, and that these energy components are related to losses and that these are the calculated losses of 6% and 6% above, which are then part of the generation energy allocation for transmission and distribution customers.

RESPONSE:

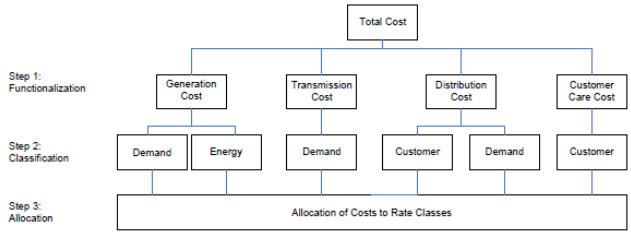
Not confirmed. As a result of losses on the transmission and distribution systems, BC Hydro generates additional energy and incurs costs that are functionalized entirely to the generation system and classified as 100 per cent energy in the F2016 COS study.

However, losses on the transmission and distribution system are accounted for in the allocation of demand-related costs to rate classes. The 4CP allocator is based on rate class load profiles that have been grossed up to reflect both transmission and distribution losses while the NCP allocator is grossed up to reflect distribution losses.

12.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-4, Page 3-31

Figure 3-1 Cost Allocation Methodology



Note that Generation energy is adjusted for losses prior to allocation. Before the pro rata calculations are done, transmission and distribution losses of 6 per cent and 6 per cent respectively are added to the energy consumption of distribution customers while transmission losses of 6 per cent are added to the energy consumption of transmission voltage customers. These loss assumptions were reviewed as part of the 2007 RDA and BC Hydro continues to believe they are valid as discussed in section 3.8.2.1.

1.12.2 Please advise that for the 2007 RDA that the loss assumption of 6% additional losses on the distribution system included loss quantities for theft of energy.

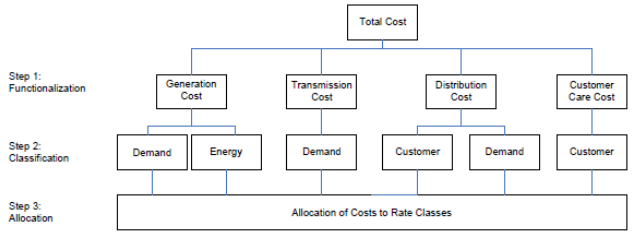
RESPONSE:

Confirmed.

12.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-4, Page 3-31

Figure 3-1 Cost Allocation Methodology



Note that Generation energy is adjusted for losses prior to allocation. Before the pro rata calculations are done, transmission and distribution losses of 6 per cent and 6 per cent respectively are added to the energy consumption of distribution customers while transmission losses of 6 per cent are added to the energy consumption of transmission voltage customers. These loss assumptions were reviewed as part of the 2007 RDA and BC Hydro continues to believe they are valid as discussed in section 3.8.2.1.

1.12.3 Please provide the estimated loss due to theft of energy, which BC Hydro included in its SMI business plans, and provide this as a quantity in GWhs/year and provide it as a % of energy generated as well as a % of energy delivered to BC Hydro customers.

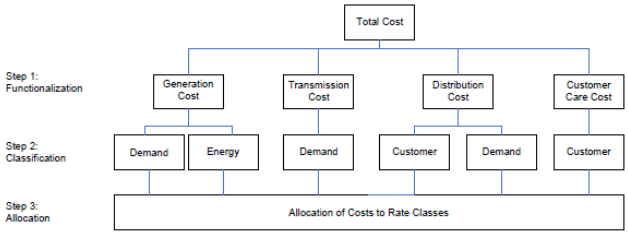
RESPONSE:

The SMI business case, which was released in January 2011, estimated that theft had increased from levels of 500 GWh per year in 2005 to 850 GWh per year by 2010. This represented a range of 1.0 to 1.7 per cent of domestic requirements and 0.6 to 1.0 per cent of total system energy including electricity trade.

12.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-4, Page 3-31

Figure 3-1 Cost Allocation Methodology



Note that Generation energy is adjusted for losses prior to allocation. Before the pro rata calculations are done, transmission and distribution losses of 6 per cent and 6 per cent respectively are added to the energy consumption of distribution customers while transmission losses of 6 per cent are added to the energy consumption of transmission voltage customers. These loss assumptions were reviewed as part of the 2007 RDA and BC Hydro continues to believe they are valid as discussed in section 3.8.2.1.

1.12.4 Please confirm that BC Hydro's SMI is helping it identify and eliminate theft of energy as a problem on its system.

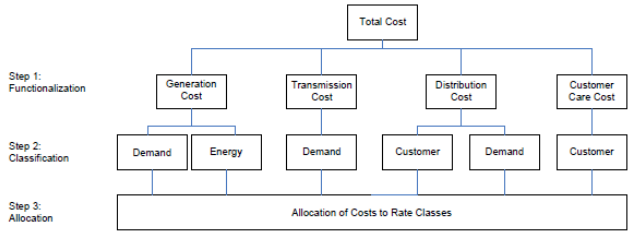
RESPONSE:

Since the initiation of the SMI program, theft from marijuana grow-ops has been substantially reduced through proactive field inspections and energy analytics enabled by SMI technology.

12.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-4, Page 3-31

Figure 3-1 Cost Allocation Methodology



Note that Generation energy is adjusted for losses prior to allocation. Before the pro rata calculations are done, transmission and distribution losses of 6 per cent and 6 per cent respectively are added to the energy consumption of distribution customers while transmission losses of 6 per cent are added to the energy consumption of transmission voltage customers. These loss assumptions were reviewed as part of the 2007 RDA and BC Hydro continues to believe they are valid as discussed in section 3.8.2.1.

1.12.5 Do the Distribution Load Shape Estimation calculations depend to some extent on fixed input assumptions about losses on the distribution system circuits and assumptions about hourly loading on those circuits?

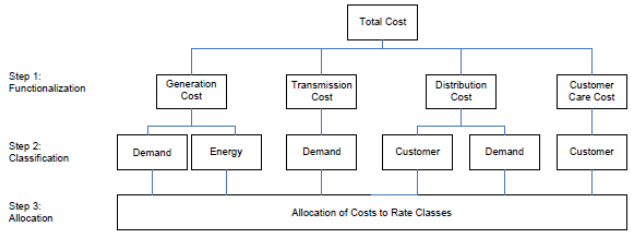
RESPONSE:

No. Loss factors and circuit loadings are done outside of the Distribution Load Shape Estimation (DLSE). The DLSE is discussed in section 3.8.2.1 of Exhibit B-1 and is used to validate the engineering studies that are used to estimate distribution system losses.

12.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-4, Page 3-31

Figure 3-1 Cost Allocation Methodology



Note that Generation energy is adjusted for losses prior to allocation. Before the pro rata calculations are done, transmission and distribution losses of 6 per cent and 6 per cent respectively are added to the energy consumption of distribution customers while transmission losses of 6 per cent are added to the energy consumption of transmission voltage customers. These loss assumptions were reviewed as part of the 2007 RDA and BC Hydro continues to believe they are valid as discussed in section 3.8.2.1.

1.12.6 Is it possible that changes in theft from the BC Hydro system may reflect in the more accurate actual metered calculations of losses, when they are available in the future, as a change from the assumption of 6% BC Hydro is currently using.

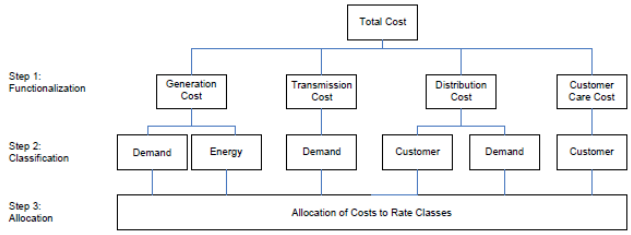
RESPONSE:

No. BC Hydro's meters do not measure losses. Losses are derived by comparing actual metered load with metered generation. Therefore, changes in theft (non-technical losses) will not change the accuracy of BC Hydro's metering. However, it may change BC Hydro's percentage loss assumptions. Please refer to BC Hydro's response to CEC IR 1.12.9.

12.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-4, Page 3-31

Figure 3-1 Cost Allocation Methodology



Note that Generation energy is adjusted for losses prior to allocation. Before the pro rata calculations are done, transmission and distribution losses of 6 per cent and 6 per cent respectively are added to the energy consumption of distribution customers while transmission losses of 6 per cent are added to the energy consumption of transmission voltage customers. These loss assumptions were reviewed as part of the 2007 RDA and BC Hydro continues to believe they are valid as discussed in section 3.8.2.1.

1.12.7 Please confirm that once BC Hydro has all of its SMI metering in place and substation circuit metering that BC Hydro may be able to reduce energy losses through more refined settings for managing voltage levels on its distribution circuits.

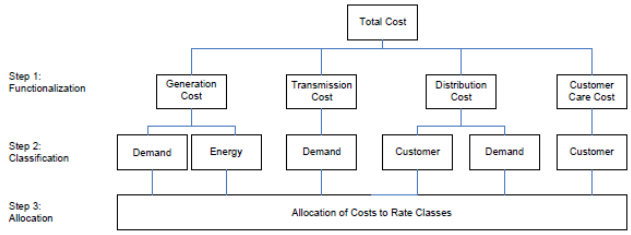
RESPONSE:

To further reduce energy consumption and technical losses through more refined settings for managing voltage levels, BC Hydro will also require remote control of the substation voltage management equipment for distribution circuits. This remote control functionality is now a standard for new installations and for significant upgrades.

12.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-4, Page 3-31

Figure 3-1 Cost Allocation Methodology



Note that Generation energy is adjusted for losses prior to allocation. Before the pro rata calculations are done, transmission and distribution losses of 6 per cent and 6 per cent respectively are added to the energy consumption of distribution customers while transmission losses of 6 per cent are added to the energy consumption of transmission voltage customers. These loss assumptions were reviewed as part of the 2007 RDA and BC Hydro continues to believe they are valid as discussed in section 3.8.2.1.

1.12.8 Are there any other activities BC Hydro is undertaking or is planning to undertake to better manage losses on the distribution system as a result of the SMI metering capabilities?

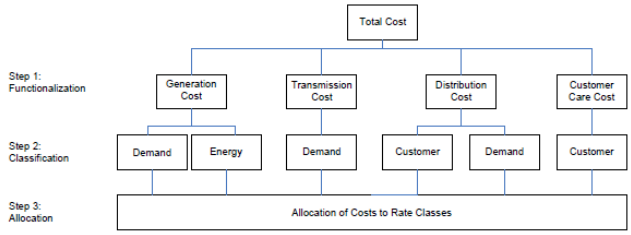
RESPONSE:

In addition to managing technical losses, SMI also includes applications to detect and manage non-technical losses.

12.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-4, Page 3-31

Figure 3-1 Cost Allocation Methodology



Note that Generation energy is adjusted for losses prior to allocation. Before the pro rata calculations are done, transmission and distribution losses of 6 per cent and 6 per cent respectively are added to the energy consumption of distribution customers while transmission losses of 6 per cent are added to the energy consumption of transmission voltage customers. These loss assumptions were reviewed as part of the 2007 RDA and BC Hydro continues to believe they are valid as discussed in section 3.8.2.1.

1.12.9 Is it possible that BC Hydro may see changes in the future to its energy loss calculations once it has fully taken advantage of its SMI initiative?

RESPONSE:

Yes. SMI will provide more precise evaluation of energy loss. BC Hydro will evaluate this in future COS studies.

13.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-5

Historically, BC Hydro prepared COS studies using actual revenues, costs, energy sales and customer load profiles from a recently completed fiscal year. If BC Hydro followed past practice, the COS study would have been based on F2014 actuals because F2015 information would not be available in time for the 2015 RDA filing. There would have been a three-year misalignment between BC Hydro's rates and a COS study based on actual costs (F2014). To avoid this disconnect, BC Hydro prepared the F2016 COS study on a forecast basis using F2016 forecast information from the approved F2016 RRA. Some historical information, such as load profiles by rate class, is used in the F2016 COS study and this is discussed in section 3.5.4.

Further information concerning BC Hydro's F2016 RRA as used in the F2016 COS study is found in sections 3.6.5, 3.7 and 3.8.

1.13.1 When will BC Hydro have actual F2015 data and or does BC Hydro have actual F2015 data now available?

RESPONSE:

Some of the actual F2015 data is now available and the remainder may be available for purposes of BC Hydro's responses to Round 2 IRs (anticipated at the end of March 2016).

In BC Hydro's view using F2015 data for purposes of the F2016 COS study will not materially impact the analysis or conclusions drawn.

13.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-5

Historically, BC Hydro prepared COS studies using actual revenues, costs, energy sales and customer load profiles from a recently completed fiscal year. If BC Hydro followed past practice, the COS study would have been based on F2014 actuals because F2015 information would not be available in time for the 2015 RDA filing. There would have been a three-year misalignment between BC Hydro's rates and a COS study based on actual costs (F2014). To avoid this disconnect, BC Hydro prepared the F2016 COS study on a forecast basis using F2016 forecast information from the approved F2016 RRA. Some historical information, such as load profiles by rate class, is used in the F2016 COS study and this is discussed in section 3.5.4.

Further information concerning BC Hydro's F2016 RRA as used in the F2016 COS study is found in sections 3.6.5, 3.7 and 3.8.

1.13.2 Has BC Hydro compared its use of 2016 forecast data to its F2015 data and if so could BC Hydro please provide that comparison as it relates to differences in COS, which would be based on using forecast data versus actual data?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.13.1.

13.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-5

Historically, BC Hydro prepared COS studies using actual revenues, costs, energy sales and customer load profiles from a recently completed fiscal year. If BC Hydro followed past practice, the COS study would have been based on F2014 actuals because F2015 information would not be available in time for the 2015 RDA filing. There would have been a three-year misalignment between BC Hydro's rates and a COS study based on actual costs (F2014). To avoid this disconnect, BC Hydro prepared the F2016 COS study on a forecast basis using F2016 forecast information from the approved F2016 RRA. Some historical information, such as load profiles by rate class, is used in the F2016 COS study and this is discussed in section 3.5.4.

Further information concerning BC Hydro's F2016 RRA as used in the F2016 COS study is found in sections 3.6.5, 3.7 and 3.8.

1.13.3 If BC Hydro has not yet done a comparison of F2015 actual with F2016 forecast data could BC Hydro please conduct such a comparison and provide the results as it may related to any differences the use of 2016 forecast data may be creating?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.13.1.

14.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-6

23 There is ample basis to continue to design rate structures with marginal cost pricing
24 while allocating BC Hydro's revenue requirement on an embedded cost basis. All

1.14.1 Please confirm that in this statement BC Hydro is confirming that it has marginal cost information available but not that it is intending to confirm that it will necessarily continue marginal cost rate structures, for instance where it is proposing flat rate structures for the base rate design.

RESPONSE:

Confirmed with respect to marginal energy and marginal generation capacity information, which is contained in section 9.2.12 of the 2013 IRP and reflected in sections 2.3.2.2 and 2.3.2.3 of Exhibit B-1.

15.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-8

> The COS Methodology Review concludes that BC Hydro's COS methodology is generally consistent with standard embedded COS methodologies. The one exception is classification of Customer Care costs as 65 per cent demand and 35 per cent customer as mandated by 2007 RDA Direction 4; all electric utilities surveyed classify Customer Care costs as 100 per cent customer. The COS Methodology Review makes 18 recommendations. BC Hydro largely concurs with these recommendations.

1.15.1 Please prepare a table of the 18 recommendations and identify those that BC Hydro agrees with and has implemented in this RDA COS study.

RESPONSE:

The requested table is provided below.

More detailed responses to the 18 COS Consultants' recommendations can be found in:

- **The Workshop 2 discussion guide starting at page 239 and continuing to page 265 of 439 of Appendix C-2A, Exhibit B-1; and**
- **The Workshop 4 consideration memo for the October 7, 2015 workshop, section 1, Appendix C-2B of Exhibit B-1.**

Generation COS Methodologies		**BC Hydro's Response**
1	**We recommend that BC Hydro consider using either a System Load Factor method (Recommendation 1A) or a Plant Capacity Factor method (Recommendation 1B) to classify hydro costs, excluding water rental costs**	**Agreed and implemented.** **BC Hydro implemented a variation of the System Load factor method (Recommendation 1A) but sees merit in both approaches (Recommendations 1A and 1B).** **Refer to pages 3-23 to 3-25 of Exhibit B-1.**
2	**For allocating demand-related hydro costs, we recommend BC Hydro first analyze how hydro units are designed or being used to serve peak loads throughout the year. To the extent that the hydro plants are designed or used to meet peak loads throughout the entire year, then a 12 coincident (CP) method is appropriate (Recommendation 2A). If the hydro plants are primarily designed or used to help meet peak loads during only a few months of the year, then methods such as 3CP or 4CP would be more appropriate (Recommendation 2B).**	**BC Hydro did not implement Recommendation 2A because its generation system planning is focussed on the winter peak.** **BC Hydro implemented Recommendation 2B and the F2016 COS study continues to use a 4CP allocator for generation demand-related costs.**

3	**As an alternative approach option for hydro costs, we recommend BC Hydro consider using the Average and Excess method for allocating demand-related hydro costs.**	**BC Hydro considered and in consultation with the COS Consultants and through stakeholder engagement rejected the Average and Excess approach. The F2016 COS continues to use a 4CP allocator for generation demand costs.**
4	**We recommend that BC Hydro continue to classify peaking thermal plant costs as demand-related and also classify associated operation and maintenance (O&M) costs, excluding fuel costs, as demand-related to the extent those costs can be separated out from O&M costs for other types of generation.**	**Agreed and implemented for Burrard. Different classifications proposed for other thermal plants. Refer to pages 3-25 and 3-26 of Exhibit B-1.**
5	**For demand-related costs associated with peaking thermal plants, we recommend that BC Hydro use an allocator that reflects the classes' contributions to the CP demands in the months when the thermal plants are primarily used.**	**The F2016 COS continues to use a 4CP allocator for generation demand-related costs, including thermal assets. Refer to pages 3-32 and 3-33 of Exhibit B-1.**
6	**We recommend that BC Hydro modify the classification of IPP and other purchased power obligations to reflect either fixed versus variable payment obligations (Recommendation 6A) or capacity versus energy usage (Recommendation 6B).**	**BC Hydro did not implement Recommendation 2A for the reasons discussed in section 5 of the Workshop 2 Consideration Memo, Attachment 4, Appendix C-2A of Exhibit B-1.** **BC Hydro uses a variation of Recommendation 6B called the "Value of Capacity' option. Refer to page 3-26 of Exhibit B-1.**
Transmission COS Methodologies		
7	**For transmission assets that are primarily used to transmit power from generation resources to the network transmission systems, we believe it is most appropriate for the costs of these resources to be classified and allocated in the same manner as costs for the generation resources.**	**Agreed and implemented.**
8	**We recommend that BC Hydro continue using the split between demand related and energy-related generation revenue requirements, excluding subsidiary income, to classify subsidiary net income.**	**Agreed and implemented.**

Transmission COS Methodologies		
9	**For backbone or network transmission, we recommend BC Hydro's use of the current Demand Only method for classification should continue to be used. When selecting an allocation method, consideration should be given as to how these transmission assets are designed and used and BC Hydro's load patterns. It may be appropriate to sub-functionalize these transmission costs between areas, such as the southern interior and other areas, using different types of allocation factors for each. Based on testimony related to the 2007 RDA, it appears that summer loads are of most importance to that portion of the BC Hydro system while loads during other times of the year may be of more importance for other parts of the system.**	**Agreed that transmission should be classified as 100 per cent demand. The F2016 COS continues to use a 4CP allocator for all transmission costs. Refer to pages 3-32 and 3-33 of Exhibit B-1.**
10	**For transmission/sub-transmission assets that essentially serve as a radial high voltage distribution system, we recommend that the Demand Only method for classification should continue to be used and consideration should be given to using one non-coincident peak (NCP) as the demand allocator.**	**Agreed and implemented. Refer to Workshop 4 consideration memo (page 84 of 205, Appendix C-2A of Exhibit B-1).**
Distribution and Customer Care COS Methodologies		
11	**We recommend BC Hydro consider more detailed sub-functionalization of distribution system costs to the degree data to support this is available.**	**Agreed and implemented.**
12	**We recommend BC Hydro consider classifying distribution substation costs as 100 per cent demand-related costs and costs for services and meters as 100 per cent customer-related costs.**	**Agreed and implemented.**
13	**We recommend if possible that BC Hydro consider using more direct assignment of distribution costs (e.g., transformers, services, and meters) based on fixed asset records, or consider using the weighted number of customers when calculating the allocation factors for transformer, services, and meter costs**	**Agreed and implemented for transformers. Weighted metering cost allocator also developed.**

Distribution and Customer Care COS Methodologies		
14	**We recommend BC Hydro review and revise the Distribution System Study to be more consistent with the theoretical foundation of the minimum system method and zero-intercept method as described in the 1992 NARUC Manual, prior to its use by BC Hydro. As an alternative, we recommend BC Hydro consider classifying distribution substation, lines, and transformer costs as all demand-related and services and meter costs as all customer-related.**	**Alternative implemented with substations, primary lines 100 per cent demand, transformers 50 per cent demand and 50 per cent customer, and services and meters 100 per cent customer.**
15	**We recommend that BC Hydro classify most, if not all, customer care costs as customer-related.**	**Agreed and implemented.**
DSM COS methodologies		
16	**We recommend that BC Hydro consider functionalizing DSM costs based on the relative proportions of BC Hydro's generation plant to transmission plant. As such, the functionalization approach would be consistent with the classification approaches.**	**Not agreed.** **Refer to pages 3-19 and 3-20 of Exhibit B-1.**
Appropriate R/C Ratios		
17	**We recommend BC Hydro consider adopting a range of reasonableness for customer class R/C ratios, with the goal of making changes in rate levels gradually over a several year period consistent with this and other ratemaking objectives when customer classes are outside of the target R/C range.**	**Agreed. However, BC Hydro did not implement this this given the Rate Rebalancing Amendment discussed on pages 2-7 to-2-8 of Exhibit B-1.**
18	**We recommend BC Hydro consider more explicitly developing a policy for how rapidly customer classes should be moved towards this range of reasonableness for R/C ratios with consideration also given to other ratemaking goals and objectives and the current legal limit on rebalancing (i.e., no more than two percentage points per year compared to the R/C ratio for that class immediately before the increase).**	**Agreed. However, BC Hydro did not implement this this given the Rate Rebalancing Amendment discussed on pages 2-7 to-2-8 of Exhibit B-1.**

15.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-8

> The COS Methodology Review concludes that BC Hydro's COS methodology is generally consistent with standard embedded COS methodologies. The one exception is classification of Customer Care costs as 65 per cent demand and 35 per cent customer as mandated by 2007 RDA Direction 4; all electric utilities surveyed classify Customer Care costs as 100 per cent customer. The COS Methodology Review makes 18 recommendations. BC Hydro largely concurs with these recommendations.

1.15.2 Where recommendation are presented as a multiple options please record each as a recommendation and show which one BC Hydro concurs with and which one it does not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.15.1.

16.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-10

Table 3-1 Summary of 2007 RDA-Related COS Methodology Changes

2007 RDA Direction	COS Methodology Change Proposed in 2015 RDA
Direction 6 – Functionalize DSM 90 per cent to Generation and 10 per cent to Transmission	Functionalize DSM to 90 per cent Generation, 5 per cent Transmission and 5 per cent Distribution on the basis that while DSM initiatives are primarily undertaken to defer Generation resources, they have some Transmission and Distribution deferral benefits. See section 3.6.6
Direction 5 – Classify Heritage hydroelectric Generation 45 per cent energy/55 per cent demand on the basis that future Resource Smart additions at Revelstoke and Mica Generating Stations are predominantly capacity-related	Use BC Hydro integrated system Load Factor[128] calculation based on loads almost entirely served by Heritage hydroelectric supply (the impact of IPPs serving load is removed) resulting in a 55 per cent energy/45 per cent demand split. See section 3.7.1
Direction 8 – Classify IPP purchases 100 per cent energy. BC Hydro is directed to prepare a study for its next RDA that examines and quantifies the capacity benefits associated with IPP EPAs	Use an approach where the fraction of IPP costs allocated to demand equals the ratio of IPP capacity benefits from the IPP EPA portfolio over IPP costs, resulting in a 93 per cent energy/7 per cent demand split. See section 3.7.3
Direction 4 – Classify Distribution costs 65 per cent demand/35 per cent customer. BC Hydro is directed to conduct a minimum system and zero intercept analysis for inclusion in its next RDA	Sub-functionalize the Distribution system: (1) classify substations and the primary system as 10 per cent demand using Non-Coincident Peak[129] (NCP) allocator; (2) direct assign transformers, with 50 per cent demand/50 per cent customer classification for rate design purposes; (3) classify the secondary system and services as 50 per cent demand/50 per cent customer and use appropriate allocators; and (4) classify meters as 100 per cent customer on a weighted customer basis. BC Hydro conducted a minimum (system) study and zero intercept analysis, but has not used the results given the shortcomings outlined in section 3.7.2
Direction 4 – Classify Customer Care costs 65 per cent demand/35 per cent customer	Classify Customer Care costs 100 per cent customer as such costs do not vary with demand levels (or energy usage) but only in proportion to the number of customers on the BC Hydro system. See section 3.7.6

1.16.1 For each entry above please supply an additional column entry showing the impact on cost classification versus 2007 RDA methodology and changes to RC ratios as a result of the change.

RESPONSE:

2007 RDA Directive	Residential (%)	SGS (%)	MGS (%)	LGS (%)	Irrigation (%)	Street Lighting (%)	Transmission (%)
Directive 6 – DSM Functionalization	**-0.1**	**-0.1**	**0.0**	**0.0**	**-0.3**	**0.0**	**0.2**
Directive 5 – Heritage Hydroelectric Classification	**0.8**	**0.0**	**0.1**	**-0.5**	**-3.3**	**1.7**	**-1.7**
Directive 8 – IPP Classification	**-0.3**	**0.0**	**0.0**	**0.2**	**1.6**	**-0.7**	**0.8**
Directive 4 – Distribution Classification	**1.5**	**-0.4**	**-3.2**	**-2.9**	**-3.5**	**-1.4**	**0.0**
Directive 4 – Customer Care Classification	**-1.1**	**0.4**	**2.5**	**2.5**	**5.1**	**-1.0**	**-0.2**

17.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-11

> Finally, a number of COS R/C ratios changed (irrespective of any proposed changes to the F2016 COS study methodology) despite using the same (2007 RDA Decision) methodology as the F2014 Fully Allocated COS.[127] This occurs for a variety of reasons including:

1.17.1 Please identify for each of the four items listed the difference in RC ratio attributable to the listed cause.

RESPONSE:

To calculate the impact of each of the four items on page 3-11 of Exhibit B-1, the F2016 COS study was updated with the 2007 RDA Decision methodology except for the following (individually backed out):

1. **Relative proportions of Generation, Transmission, Distribution and Customer Care costs were adjusted back to F2014 proportions;**
2. **F2014 energy allocators were substituted for F2016 energy allocators;**
3. **F2014 demand (CP and NCP) allocators were substituted for F2016 demand allocators; and**
4. **F2014 revenue was grossed up F2016 revenue forecast and substituted for F2016 revenue.**

Percentage changes in the table are the COS results with all F2016 data less the results with the described changes in the items listed above.

	Item 1 (%)	Item 2 (%)	Item 3 (%)	Item 4 (%)
Residential	**-1.7**	**-0.3**	**-0.3**	**1.5**
SGS	**-1.2**	**+6.4**	**+4.9**	**-16.8**
MGS	**-0.2**	**+2.2**	**-7.1**	**5.3**
LGS	**+0.8**	**+0.1**	**+1.2**	**-4.5**
Irrigation	**-2.7**	**-6.0**	**-4.8**	**14.0**
Street Lighting	**-3.2**	**+0.7**	**-4.3**	**-1.6**
Transmission	**+4.3**	**-2.6**	**0.0**	**5.9**

18.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-13

As described in section 2.3.2.1 of the Application, since the implementation of SMI in F2014 SMI daily register reads are available for almost all BC Hydro customers. Ratio expansions[130] can be done on a daily basis rather than an annual or monthly basis as they were in the past. Also, BC Hydro has a statistical sample of about 45,000 customers with hourly load information from which it can conduct more detailed load research. With the capability to create almost on-demand detailed customer load profiles, regulatory analysis, rate design and peak load forecasting have been improved. BC Hydro estimates that the new hourly sample of 45,000 would yield within 1 per cent accuracy at 99 per cent confidence level.

1.18.1 Please identify and quantify the impact of improved load research data on any cost allocations made or on the RC ratios resulting from the COS.

RESPONSE:

The improved load research data, in the form of increased sample sizes, results in more accurate estimates of the rate class peak demand values, which are inputs to the F2016 COS. The improved peak demand estimates are expected to be within 1 per cent with a 99 per cent confidence for the LGS and MGS rate classes, and within 5 per cent with a 95 per cent confidence for the SGS and Residential rate classes. Previously, the restricted size of load research samples limited the accuracy of these rate class peak demands to 10 per cent with a 90 per cent confidence.

18.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-13

As described in section 2.3.2.1 of the Application, since the implementation of SMI in F2014 SMI daily register reads are available for almost all BC Hydro customers. Ratio expansions[130] can be done on a daily basis rather than an annual or monthly basis as they were in the past. Also, BC Hydro has a statistical sample of about 45,000 customers with hourly load information from which it can conduct more detailed load research. With the capability to create almost on-demand detailed customer load profiles, regulatory analysis, rate design and peak load forecasting have been improved. BC Hydro estimates that the new hourly sample of 45,000 would yield within 1 per cent accuracy at 99 per cent confidence level.

1.18.2 Please confirm that BC Hydro uses the actual load data for the purposes of the COS.

RESPONSE:

Allocations of energy-related costs are based on actual metered energy while allocations of demand-related costs are based on estimates of each rate class' contribution to 4CP or NCP allocation factors. Since these estimates are based on sampled data they may not exactly match actual loads.

Please also refer to BC Hydro's response to CEC IR 1.18.1.

18.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-13

As described in section 2.3.2.1 of the Application, since the implementation of SMI in F2014 SMI daily register reads are available for almost all BC Hydro customers. Ratio expansions[130] can be done on a daily basis rather than an annual or monthly basis as they were in the past. Also, BC Hydro has a statistical sample of about 45,000 customers with hourly load information from which it can conduct more detailed load research. With the capability to create almost on-demand detailed customer load profiles, regulatory analysis, rate design and peak load forecasting have been improved. BC Hydro estimates that the new hourly sample of 45,000 would yield within 1 per cent accuracy at 99 per cent confidence level.

1.18.3 Please confirm that the transmission and distribution systems are planned and built based on meeting design load requirements for customers and not necessarily actual load used profiles.

RESPONSE:

Confirmed.

18.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-13

As described in section 2.3.2.1 of the Application, since the implementation of SMI in F2014 SMI daily register reads are available for almost all BC Hydro customers. Ratio expansions[130] can be done on a daily basis rather than an annual or monthly basis as they were in the past. Also, BC Hydro has a statistical sample of about 45,000 customers with hourly load information from which it can conduct more detailed load research. With the capability to create almost on-demand detailed customer load profiles, regulatory analysis, rate design and peak load forecasting have been improved. BC Hydro estimates that the new hourly sample of 45,000 would yield within 1 per cent accuracy at 99 per cent confidence level.

1.18.4 Please discuss whether or not this difference between actual load data and design load planning could cause differences in cost allocations or RC ratios.

RESPONSE:

The difference between actual load data (as used for COS studies) and design load planning (as used for sizing of equipment) have no immediate impact on cost allocations or R/C ratios. Design load planning must consider the maximum loading expected in an area over several years or decades, while the R/C ratios are applicable to a given year only.

19.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-14

> The subsidiary net income, which is derived primarily from Powerex Corp. (**Powerex**), is assigned to the Generation function on the basis that the income is associated with energy sales.

1.19.1 Please advise whether or not the subsidiary net income is deducted from the costs of energy.

RESPONSE:

Subsidiary Net income is deducted from the costs of Generation in the F2016 COS study. The net income is subsequently classified between energy and demand using the average classification factor of the other costs in the Generation function.

19.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-14

> The subsidiary net income, which is derived primarily from Powerex Corp. (**Powerex**), is assigned to the Generation function on the basis that the income is associated with energy sales.

1.19.2 Please describe how losses involved in the sale of energy and generation of net income in the subsidiary are allocated and advise whether or not the losses offset this income when it is being allocation.

RESPONSE:

Losses occurring on the BC Hydro transmission system do not impact Powerex net income:

- **Section 9.2 of the Transfer Pricing Agreement (TPA) between and Powerex and BC Hydro states: "B.C. Hydro shall pay for all transmission charges and shall self-supply all losses and ancillary services charges, on the Transmission System for electricity transactions under this Agreement"; and**
- **Section 1.1.31 of the TPA defines "Transmission System" as the bulk transmission system owned by BC Hydro.**

19.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-14

> The subsidiary net income, which is derived primarily from Powerex Corp. (**Powerex**), is assigned to the Generation function on the basis that the income is associated with energy sales.

1.19.3 Please advise whether or not the subsidiary net income is allocated all to energy or is there a split of the allocation between energy and demand.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.19.1.

20.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-15

3.6.4 Customer Care

The Customer Care function includes services related to revenue collection and customer account and relationship management, as well as planning and sustainment of the Information Technology (**IT**) infrastructure required to deliver these services. Revenue collection activities include meter reading, bill generation and delivery, billing exception identification and resolution, payment processing, collections and investigation of electricity theft. Customer account and relationship management are provided through mass market contact channels (call centre, internet portal) and dedicated account representatives for BC Hydro's largest customers, as well as resolution of claims and complaints.

1.20.1 Please describe what happens to costs involved with providing service to customers, such as connections, disconnections, trouble investigations and work orders for specific customer requirements.

RESPONSE:

Nearly all the costs referenced in this IR are functionalized as Customer Care in the F2016 COS study but a small amount relate to manual disconnections and reconnections performed by T&D Field and Grid Operations. These T&D costs are functionalized as Distribution in the F2016 COS study. More information on Customer Care-related costs are provided in BC Hydro's response in the confidential version of BCOAPO IR 1.183.1.

20.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-15

3.6.4 Customer Care

The Customer Care function includes services related to revenue collection and customer account and relationship management, as well as planning and sustainment of the Information Technology (**IT**) infrastructure required to deliver these services. Revenue collection activities include meter reading, bill generation and delivery, billing exception identification and resolution, payment processing, collections and investigation of electricity theft. Customer account and relationship management are provided through mass market contact channels (call centre, internet portal) and dedicated account representatives for BC Hydro's largest customers, as well as resolution of claims and complaints.

1.20.2 Please describe what happens to costs involved in marketing services to customers.

RESPONSE:

Most marketing (advertising) costs are associated with DSM, which are deferred and amortized over 15 years. The treatment of DSM costs in the F2016 COS study is described in section 3.6.6 of Exhibit B-1.

Besides DSM, the second largest advertising cost is OM&A within the Communications group which is part of Corporate Affairs. The F2016 COS study functionalizes all corporate costs in accordance with each function's share of F2016 RRA OM&A.

A small portion of advertising cost may be attributed to Customer Service if there is a specific campaign, for example promotion of paperless billing. These costs would be functionalized to Customer Care in the F2016 COS study.

21.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-17

> associated with IT are approximately $112 million in the F2016 COS study and these are currently treated like a corporate expense and functionalized to all business groups using a high level O&M allocator.

1.21.1 When the IT costs are treated like a corporate expense and functionalized to all business groups are these allocations done on the basis of the annual expenditures for each of the business groups or some other methodology?

RESPONSE:

As described in section 3.6.5.1 of Exhibit B-1, BC Hydro examined several methods of potentially functionalizing IT costs. Due to the factors listed on page 3-18 of Exhibit B-1, it was determined to be most appropriate to functionalize total IT costs with the same proportions used to functionalize corporate O&M. Corporate O&M is functionalized proportionate to the functionalization of O&M by business unit.

22.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-19

As part of the RRA process, T&D operating costs are already split between Transmission and Distribution using a methodology that originated in BC Hydro's 1997 Wholesale Transmission Service proceeding and involves a detailed review of all operating costs within T&D. For example, Line 23 on Schedule 5.4 of the RRA shows that 53.4 per cent of F2016 T&D operating cost is functionalized as Transmission while the remaining 46.6 per cent is functionalized as Distribution; refer to the F2016 COS model at Appendix E of the Application. BC Hydro relies on this information for F2016 COS purposes.

1.22.1 Is the 1997 Wholesale Transmission Service detailed review of all operating costs within T&D available as a report and is it on the record of this proceeding? If not please provide.

RESPONSE:

As noted in BC Hydro's response to CEC IR 1.22.2, BC Hydro is not relying on the 1997 review for the purpose of splitting T&D operating costs. Therefore, while the Wholesale Transmission Service review is not part of the record for this proceeding, BC Hydro has not provided a copy of that review given that it not relevant to the review of the 2015 RDA.

22.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-19

As part of the RRA process, T&D operating costs are already split between Transmission and Distribution using a methodology that originated in BC Hydro's 1997 Wholesale Transmission Service proceeding and involves a detailed review of all operating costs within T&D. For example, Line 23 on Schedule 5.4 of the RRA shows that 53.4 per cent of F2016 T&D operating cost is functionalized as Transmission while the remaining 46.6 per cent is functionalized as Distribution; refer to the F2016 COS model at Appendix E of the Application. BC Hydro relies on this information for F2016 COS purposes.

1.22.2 Please discuss what might have changed in the costing of T&D functions since 1997 that would warrant BC Hydro relying on this 1997 study.

RESPONSE:

For clarity, BC Hydro is not relying on the 1997 study as its basis for analysing the F2016 T&D operating costs. The methodology referenced in Exhibit B-1, page 3-19 relates to a fully allocated cost of service study that was used in the 1997 Wholesale Transmission Service review.

Since F2012 BC Hydro has used a more granular method to split operating costs between T&D. The F2016 T&D costs were allocated to BC Hydro's functions (Transmission, Distribution and Generation) based on input from managers to identify costs that could be directly assigned, or where direct assignment was not possible the costs were allocated based on the following:

a) Maintenance and/or capital expenditures; or

b) Regular FTEs or labour expenses; or

c) Historical expenditures.

23.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1,Page 3-19

> At Workshop 2 BC Hydro identified DSM as a functionalization issue, and proposed a departure from the Commission's 2007 RDA Decision Direction 6 functionalizing DSM-related costs as 90 per cent Generation and 10 per cent Transmission to functionalizing DSM-related costs as 90 per cent Generation, 5 per cent Transmission and 5 per cent Distribution.

1.23.1 Please confirm that the purposes of DSM investment are to avoid the higher costs of future generation supply for all customers and to ensure that all customers have an opportunity to use their electric energy as efficiently as practicable.

RESPONSE:

BC Hydro invests in DSM for a number of reasons, including:

- **Avoiding the costs of future generation supply;**
- **Avoiding the costs of future transmission and distribution investments; and**
- **Providing customers opportunities to use their electric energy efficiently and reduce their electricity bills.**

23.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1,Page 3-19

At Workshop 2 BC Hydro identified DSM as a functionalization issue, and proposed a departure from the Commission's 2007 RDA Decision Direction 6 functionalizing DSM-related costs as 90 per cent Generation and 10 per cent Transmission to functionalizing DSM-related costs as 90 per cent Generation, 5 per cent Transmission and 5 per cent Distribution.

1.23.2 Please confirm that most of the DSM expenditures and programs have been designed to save energy and that BC Hydro continues to focus on energy savings, though it has started to explore more program opportunities to focus on capacity savings.

RESPONSE:

Confirmed. Most of BC Hydro's DSM programs have been designed to save energy, though there are also associated capacity savings. BC Hydro has started to explore opportunities to focus on capacity savings.

23.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1,Page 3-19

At Workshop 2 BC Hydro identified DSM as a functionalization issue, and proposed a departure from the Commission's 2007 RDA Decision Direction 6 functionalizing DSM-related costs as 90 per cent Generation and 10 per cent Transmission to functionalizing DSM-related costs as 90 per cent Generation, 5 per cent Transmission and 5 per cent Distribution.

1.23.3 Please confirm that in the long term energy savings that are applicable year round will have an impact of reducing the capacity requirements of the transmission and distribution system.

RESPONSE:

DSM energy savings can have the impact of reducing the capacity requirements of the transmission and distribution system.

23.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1,Page 3-19

15 At Workshop 2 BC Hydro identified DSM as a functionalization issue, and proposed
16 a departure from the Commission's 2007 RDA Decision Direction 6 functionalizing
17 DSM-related costs as 90 per cent Generation and 10 per cent Transmission to
18 functionalizing DSM-related costs as 90 per cent Generation, 5 per cent
19 Transmission and 5 per cent Distribution.

1.23.4 Please confirm that for a savings of 1 MW at a 50% load factor average over a year the energy savings would be worth approximately 90% of the savings and 10% would be related to the capacity, while at a 30% load factor the savings split would be more like 84% energy and 16% capacity. (assume cost of new power $100/MWh and the cost of capacity $50/kw-year)

RESPONSE:

Confirmed with respect to the calculations involving a 50 per cent load factor and a 30 per cent load factor.

23.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1,Page 3-19

15 At Workshop 2 BC Hydro identified DSM as a functionalization issue, and proposed
16 a departure from the Commission's 2007 RDA Decision Direction 6 functionalizing
17 DSM-related costs as 90 per cent Generation and 10 per cent Transmission to
18 functionalizing DSM-related costs as 90 per cent Generation, 5 per cent
19 Transmission and 5 per cent Distribution.

1.23.5 Please confirm that the above analysis provides a reasonable level of confirmation that BC Hydro's 90% Generation, 5% Transmission, and 5% Distribution represents a suitably appropriate allocation of DSM.

RESPONSE:

BC Hydro arrived at a DSM functionalization of 90 per cent Generation, 5 per cent Transmission and 5 per cent Distribution based on, among other things, an adjusted system load factor of 55 per cent.

24.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-20

the underlying asset. The functionalization for several regulatory account amounts[135] was adjusted, each with a small impact to total costs assigned by function. The largest of these in F2016 was a change in the functionalization of the Rate Smoothing regulatory account, an amount of $122.4 million in the F2016 RRA. This amount was previously assigned to each function proportionate with functionalized O&M. The COS Consultants recommended that this amount be functionalized

1.24.1 Please describe the source of the entry amounts being accumulated in the Rate Smoothing Regulatory Account and discuss what is giving rise to the variability which requires smoothing.

RESPONSE:

Subsection 3(u) of Directive No. 6 requires the Commission to order BC Hydro to defer the listed amounts to the Rate Smoothing Regulatory Account in F2015 and F2016. BC Hydro respectfully submits that treatment of the Rate Smoothing Regulatory Account that is not related to the F2016 COS is outside the scope of the 2015 RDA. BC Hydro's deferral and regulatory accounts will be discussed in the F2017 RRA, which will be filed in February 2016.

24.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-20

the underlying asset. The functionalization for several regulatory account amounts[135] was adjusted, each with a small impact to total costs assigned by function. The largest of these in F2016 was a change in the functionalization of the Rate Smoothing regulatory account, an amount of $122.4 million in the F2016 RRA. This amount was previously assigned to each function proportionate with functionalized O&M. The COS Consultants recommended that this amount be functionalized

1.24.2 Why is the rate smoothing being done?

RESPONSE:

The issue of why rate smoothing is being done is not relevant to the F2016 COS study functionalization of regulatory accounts.

The rate smoothing account, which is part of the framework resulting from Direction No. 7, will be addressed as part of the F2017 RRA.

25.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-21

> The classification of the interest on the deferral accounts was also updated to be consistent with that used for Cost of Energy. This amount was previously classified using the classification ratio applied to all of the Generation function. In F2016, this change is applicable to an amount of $23.8 million.

1.25.1 Please provide a table of deferral account balances and the relevant interest applicable to each.

RESPONSE:

The table below is populated with data that was provided in Appendix E, Schedule RRA 2.1.

These deferral accounts are all Cost of Energy variance accounts. Cost of Energy is functionalized as Generation, including the interest portion.

Deferral Account	F2016 End of Year Balance ($ million)	F2016 Interest ($ million)
Heritage Deferral Account	**35.4**	**1.9**
Non-Heritage Deferral Account	**209.0**	**11.2**
Trade Income Deferral Account	**200.2**	**10.7**

25.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-21

> The classification of the interest on the deferral accounts was also updated to be consistent with that used for Cost of Energy. This amount was previously classified using the classification ratio applied to all of the Generation function. In F2016, this change is applicable to an amount of $23.8 million.

1.25.2 Please explain the appropriate alignment of each of the accounts to an appropriate functionalization methodology and explain why each is aligned.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.25.1.

26.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-24

However, as stated in section 2.1.2 of the Workshop 4 consideration memo, BC Hydro believes that both the load factor and capacity factor approaches have merit. As a result, and to respond to AMPC, Transmission Service customer and CEC concerns with the system load factor approach, BC Hydro brought forward two F2016 COS study sensitivities:

1. Forty-five per cent energy/55 per cent demand split resulting from a capacity factor approach (Sensitivity Number 1); and
2. Fifty per cent energy/50 per cent demand split based on BC Hydro's historic classification of Heritage hydroelectric facilities (Sensitivity Number 2). A 50 per cent energy/50 per cent demand split is a compromise approach that recognizes the limitations of and roughly represents an average of the system load factor and capacity factor approaches.

1.26.1 Please describe the merits of the capacity factor approach in contrast to the system load factor approach.

RESPONSE:

BC Hydro discussed the merits of different hydroelectric classification methodologies in section 4 of the Workshop 4 discussion guide found at Appendix C-2B of Exhibit B-1.

27.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-25

- FNG – use a load factor approach specific to the Fort Nelson service territory to classify FNG's O&M and capital generation costs. This results in a 74 per cent energy and 26 per cent demand classification. Fuel costs are classified as 100 per cent energy;
- PRG – For simplicity, use the system load factor with no adjustment for IPP supply to classify PRG's O&M and capital generation costs. This results in a 60 per cent energy and 40 per cent demand classification. Fuel costs are classified as 100 per cent energy; and
- Burrard – classify Burrard O&M and capital costs as 100 per cent demand with associated fuel costs treated as 100 per cent energy.

1.27.1 For each of the thermal plants please describe when they are run during a year and why each is run.

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 1.5.3.

27.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-25

- FNG – use a load factor approach specific to the Fort Nelson service territory to classify FNG's O&M and capital generation costs. This results in a 74 per cent energy and 26 per cent demand classification. Fuel costs are classified as 100 per cent energy;
- PRG – For simplicity, use the system load factor with no adjustment for IPP supply to classify PRG's O&M and capital generation costs. This results in a 60 per cent energy and 40 per cent demand classification. Fuel costs are classified as 100 per cent energy; and
- Burrard – classify Burrard O&M and capital costs as 100 per cent demand with associated fuel costs treated as 100 per cent energy.

1.27.2 Please supply the data supporting when the plants are run.

RESPONSE:

Attachment 1 to this IR response provides monthly energy production from the three thermal plants between F2009 and F2015.

Thermal Generation F2009-F2015

VOLUME (MW.h)

F2015	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
FNG	16,247	12,710	13,378	15,612	15,248	13,606	14,263	16,615	17,426	17,316	16,011	17,081	**185,513**
BUR	12,611	256	-	792	827	218	547	8,044	1,114	398	506	791	**26,104**
RPG	50	25	884	81	51	98	-	44	44	28	51	48	**1,404**
	28,908	**12,991**	**14,262**	**16,485**	**16,126**	**13,922**	**14,810**	**24,703**	**18,584**	**17,742**	**16,568**	**17,920**	**213,021**
F2014													
FNG	11,539	12,019	13,774	13,946	14,813	14,034	13,756	15,808	18,522	18,459	18,090	17,546	**182,306**
BUR	442				1,844	16,871	5,135	9,706	40,245	567	1,171	8,454	**84,435**
RPG	875	36	126	30	61	7	52	36	45	26	35	29	**1,358**
	12,856	**12,055**	**13,900**	**13,976**	**16,718**	**30,912**	**18,943**	**25,550**	**58,812**	**19,052**	**19,296**	**26,029**	**268,099**
F2013													
FNG	8,710	6,125	3,892	7,306	5,982	4,514	10,043	10,004	10,689	11,692	8,452	8,522	**95,931**
BUR	3,760	822	-	4,525	773	527	236	10,746	162	1,060	1,122	1,212	**24,947**
RPG	66	51	56	55	218	53	198	53	49	67	24	13	**902**
	12,536	**6,998**	**3,947**	**11,886**	**6,973**	**5,094**	**10,477**	**20,803**	**10,901**	**12,819**	**9,599**	**9,747**	**121,780**
F2012													
FNG	15,734	10,052	1,479	-	1	11,234	10,592	10,871	19,020	15,124	20,699	8,255	**123,060**
BUR	1,128	230	663	423	1,259	1,454	797	7,965	656	460	260	3,829	**19,124**
RPG	15	9	31	-	91	92	249		68		30	87	**672**
	16,877	**10,291**	**2,173**	**423**	**1,351**	**12,780**	**11,638**	**18,836**	**19,744**	**15,584**	**20,989**	**12,171**	**142,856**
F2011													
FNG	11,455	14,850	14,065	14,605	14,454	11,546	15,875	16,749	19,861	19,414	17,464	18,459	**188,797**
BUR	-	194	-	14,844	580	374	759	38,922	596	467	355	1,194	**58,285**
RPG	-	9	-	1,044	1,364	6	852	213	315	-	-	481	**4,284**
	11,455	**15,053**	**14,065**	**30,493**	**16,398**	**11,926**	**17,486**	**55,884**	**20,772**	**19,881**	**17,819**	**20,134**	**251,366**
F2010													
FNG	15,536	5,440	10,299	13,038	13,014	12,571	16,655	14,505	19,702	20,041	17,091	16,430	**174,322**
BUR	26,441	2,008	-	-	26,239	124,191	-	33,168	5,402	1,265	187	-	**218,901**
RPG	2	2,855	15	3,959	-	323	85	-	-	-	-	27	**7,266**
	41,979	**10,303**	**10,314**	**16,997**	**39,253**	**137,085**	**16,740**	**47,673**	**25,104**	**21,306**	**17,278**	**16,457**	**400,489**
F2009													
FNG	19,000	19,000	17,000	17,000	16,000	14,000	18,000	17,000	20,000	18,000	17,000	16,000	**208,000**
BUR	15,000	1,000	-	-	-	-	2,000	1,000	56,000	22,000	-	6,000	**103,000**
RPG	-	-	-	-	-	-	1,000	-	-	-	-	-	**1,000**
	34,000	**20,000**	**17,000**	**17,000**	**16,000**	**14,000**	**21,000**	**18,000**	**76,000**	**40,000**	**17,000**	**22,000**	**312,000**

28.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-26

> BC Hydro proposes to continue classifying the 90 per cent portion of DSM that has been functionalized as Generation-related, in the same way as overall Generation costs. As described in section 3.6.6, BC Hydro's rationale for functionalizing 90 per cent of DSM to Generation is that DSM expenditures are primarily incurred to avoid generation-related costs, which also avoids the classification of those same costs into energy and demand. Therefore, to be consistent with the rationale for

1.28.1 Please confirm that this approach to DSM would not account for a contribution to transmission and distribution capacity.

RESPONSE:

Not confirmed. In the F2016 COS study DSM-related costs are functionalized 90 per cent to Generation, 5 per cent to Transmission and 5 per cent to Distribution.

This DSM classification reflects DSM's contribution to transmission and distribution capacity since transmission costs in the F2016 COS study are classified as 100 per cent demand-related while distribution costs are classified, in aggregate, approximately 75 per cent demand-related.

29.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-27 & 3-28

- Substations and primary system classified 100 per cent demand;
- Transformers classified 50 per cent demand and 50 per cent customer;
- Secondary/services asset category split 50 per cent secondary and 50 per cent services:
  - Secondary portion classified 100 per cent demand;
  - Service portion classified 100 per cent customer; and
- Meters classified 100 per cent customer.

1.29.1 Please describe the transformers on the system which are being classified as 50% demand and 50% customer and elaborate on why this judgement is being made.

RESPONSE:

Any transformer costs in the F2016 COS study are associated with BC Hydro owned units. The following table describes their characteristics:

	Overhead	Underground
Number of Transformers	**278,000**	**59,000**
Range of Sizes in Service (kVA)	**3 - 500**	**5 - 1,500**
Average Age (Years)	**10**	**16**

BC Hydro's reasons for directly assigning transformers to rate classes and then classifying the costs as 50 per cent demand and 50 per cent customer are described on pages 101 and 102 of 205 of the Workshop 4 consideration memo which is found at Appendix C-2B of Exhibit B-1. The classification of these costs does not impact R/C ratios because transformer costs are directly assigned to rate classes. Instead, transformer classification impacts total customer-related and demand-related distribution costs in the F2016 COS study.

30.0 B. Chapter 3 – Cost of Service

Reference: Exhibit B-1, Page 3-32

> Generation demand-related and Transmission costs are typically allocated on the basis of the system's CP demand because it is combined system demand at peak times that drives Generation capacity and Transmission needs. A rate class's 4CP allocation is calculated as a five-year average of the sum of that rate class's demand at each winter month's peak hour divided by the sum of all rate classes' demand during those same hours. Stakeholders providing Workshop 4-related written

1.30.1 Please confirm that the generation capacity and the transmission capacity in the system are designed to deliver the maximum design coincident peak forecast.

RESPONSE:

Confirmed. Total generation capacity is sized to meet coincident peak forecasts for the entire system while transmission system capacity can be generally sized to meet coincident peak forecasts for the entire system or for a particular region.

31.0 C. Chapter 4 – Rate Class Determination

Reference: Exhibit B-1, page 4-1

> BC Hydro uses the expression 'segmentation' to refer to the creation of sub-classes of customers defined by certain characteristics. Potential segmentation falls into two categories: that which may be justifiable on a cost of service basis and that which cannot. Additional segmentation based on cost of service can lead to increased transparency and better matching of costs and revenues.

1.31.1 Please explain the characteristics that make segmentation justifiable on a cost of service basis versus that which is not.

RESPONSE:

BC Hydro's approach to segmentation is cost based. Customer characteristics that influence costs include customer use at system coincident peak and to a lesser extent, customer size which is determined by their annual peak demand.

"Potential segmentation" refers to the exploration of different customer characteristics which will ultimately be determined to be cost-based differentiation or not. Where BC Hydro concludes there is no cost of service rationale, BC Hydro rejects creating sub-classes. An example is residential customer income; there is no cost of service basis for a residential low income sub-class.

31.0 C. Chapter 4 – Rate Class Determination

Reference: Exhibit B-1, page 4-1

BC Hydro uses the expression 'segmentation' to refer to the creation of sub-classes of customers defined by certain characteristics. Potential segmentation falls into two categories: that which may be justifiable on a cost of service basis and that which cannot. Additional segmentation based on cost of service can lead to increased transparency and better matching of costs and revenues.

1.31.2 Will a sub-class be refused if it is not justifiable on a cost of service basis? Please explain.

RESPONSE:

Generally speaking, creating a sub-class of customers that is not cost-based is difficult to rationalize as it likely to be unduly discriminatory and unduly preferential. This is because this approach creates an inequity between ratepayers as some customer classes would be required to pay an amount greater than the cost of providing their service while others would be paying less than the cost of serving them.

32.0 C. Chapter 4 – Rate Class Determination

Reference: Exhibit B-1, page 4-8

- The smallest general service customers tend to have lower load factors than MGS and LGS customers, as shown in Figure 4-1 below. Load factor is a customer's average demand divided by their peak demand. Low load factors are indicative of customers that are relatively more costly to serve, and load factor is therefore a consideration when evaluating rate class segmentation.[158] Cumulatively, more than 50 per cent of SGS customers have a load factor under 40 per cent, while that same load factor range applies to only around 30 per cent of MGS and LGS customers.

1.32.1 Can 'load factor' be described as a measure of the 'infrequency of use' of the customer?

RESPONSE:

Load factor is not necessarily a matter of frequency or infrequency of use of the customer. Load factor is better described as the extent to which a system is used at full capacity. A customer may still use the system at every measured interval (same frequency); however, the usage at each interval will be some portion of the usage that occurs at the interval with the maximum usage (for the period that load factor is being considered).

32.0 C. Chapter 4 – Rate Class Determination

Reference: Exhibit B-1, page 4-8

- The smallest general service customers tend to have lower load factors than MGS and LGS customers, as shown in Figure 4-1 below. Load factor is a customer's average demand divided by their peak demand. Low load factors are indicative of customers that are relatively more costly to serve, and load factor is therefore a consideration when evaluating rate class segmentation.[158] Cumulatively, more than 50 per cent of SGS customers have a load factor under 40 per cent, while that same load factor range applies to only around 30 per cent of MGS and LGS customers.

1.32.1 Can 'load factor' be described as a measure of the 'infrequency of use' of the customer?

1.32.1.1 If no, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.32.1.

32.0 C. Chapter 4 – Rate Class Determination

Reference: Exhibit B-1, page 4-8

- The smallest general service customers tend to have lower load factors than MGS and LGS customers, as shown in Figure 4-1 below. Load factor is a customer's average demand divided by their peak demand. Low load factors are indicative of customers that are relatively more costly to serve, and load factor is therefore a consideration when evaluating rate class segmentation.[158] Cumulatively, more than 50 per cent of SGS customers have a load factor under 40 per cent, while that same load factor range applies to only around 30 per cent of MGS and LGS customers.

1.32.2 Please provide further clarification of why lower load factors are typically more costly to serve and or confirm that this is because the fixed capital investment costs to provide service will be spread over a smaller energy volume billing.

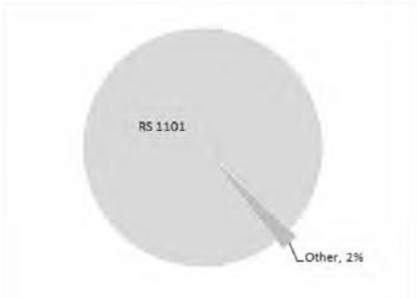
RESPONSE:

Confirmed with respect the statement that generally for low load factor customers, fixed capital investment costs to provide service are spread over a smaller energy volume billing. There may be cases, however, where the low load factor customer utilizes utility facilities only at times of low peak demand for those facilities, and therefore is able to avoid or minimize the need for fixed capital investments by BC Hydro to serve the customer. In those cases, the low load factor customer could be less costly to serve than the typical customer.

33.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-4

Figure 5-1 F2015 Residential Accounts



1.33.1 What sub-class(es) are included in the 2% that are included in "Other" ? Please explain.

RESPONSE:

Of the 1.7 million Residential rate class accounts (F2015), 2 per cent are served under following Residential Rate Schedules:

Residential Rate Schedules			
RS 1107	RS 1122	RS 1148	RS 1161
RS 1121	RS 1127	RS 1151	RS 1289

34.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-9

Figure 5-3 Total Consumption by Region (GWh)

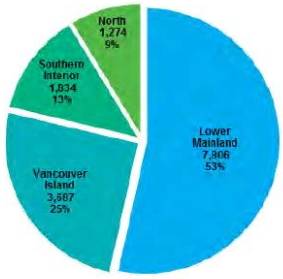
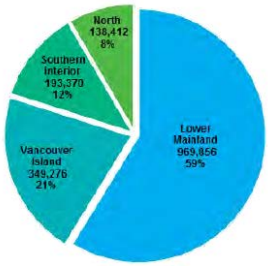


Figure 5-4 Customer Accounts by Region



1.34.1 Please provide BC Hydro's views as to why Vancouver Island has a higher proportion of consumption relative to their proportion of customer count in comparison to those customers in other regions.

RESPONSE:

The reason why Vancouver Island has a higher proportion of consumption relative to the proportion of customer count in comparison to those customers in other regions is that amongst other things, it has a higher proportion of electrically heated homes. Please also refer to BC Hydro's response to CEC IR 1.48.1.

34.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-9

Figure 5-3 Total Consumption by Region (GWh)

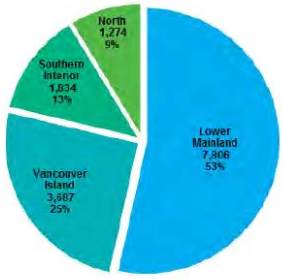
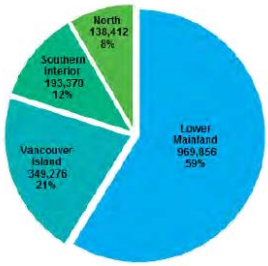


Figure 5-4 Customer Accounts by Region



1.34.2 Please provide BC Hydro's views as to why Vancouver Lower Mainland has a lower proportion of consumption relative to their proportion of customer count in comparison to those customers in other regions.

RESPONSE:

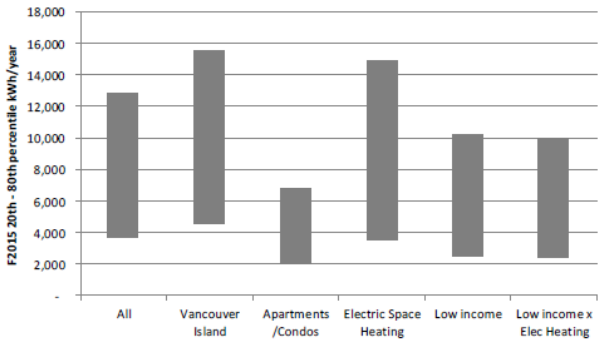
The reason why the Lower Mainland has a lower proportion of consumption relative to the proportion of customer count in comparison to those customers in other regions is that amongst other things, it has a higher mix of apartment/condos than other regions. BC Hydro's views on factors driving electricity consumption are discussed in Exhibit B-1 on page 5-69.

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.1 Why does BC Hydro include a separate geographic segment for Vancouver Island as opposed to segmenting it according to the same classifications as above?

RESPONSE:

The illustrative segments of customer characteristics are consistent with those discussed at the 2015 RDA stakeholder engagement residential rate workshops.

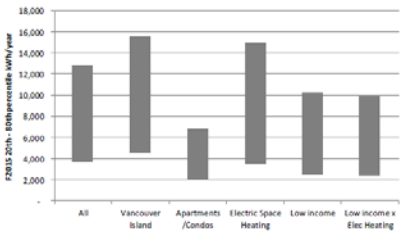
Please refer BC Hydro's response to CEC IR 1.35.2 to see a breakdown of Vancouver Island by sub-segments.

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

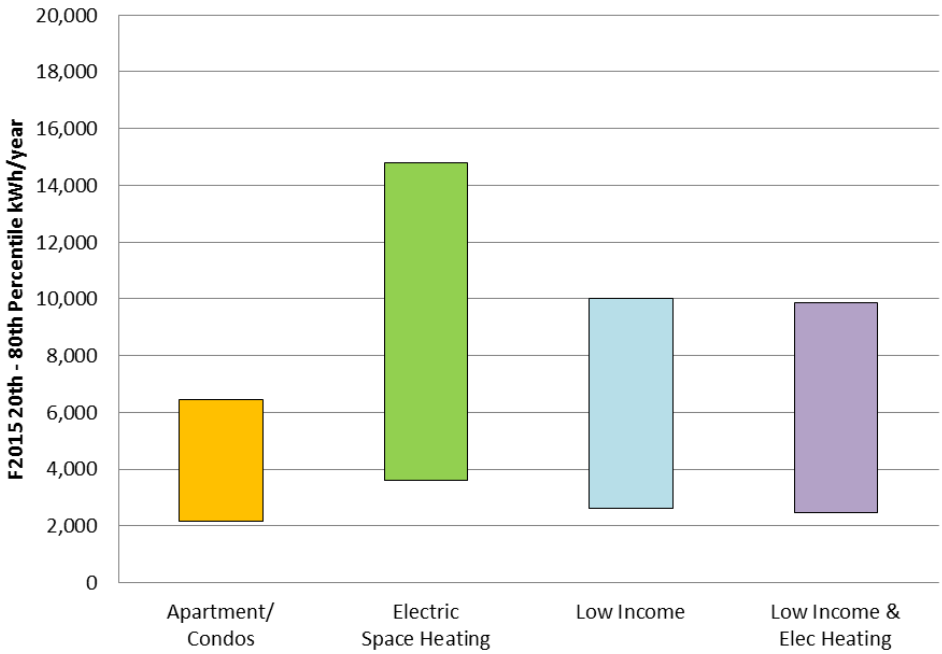
Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.2 Please provide the same information as that provided in Figure 5-12 for Vancouver Island.

RESPONSE:

Using the 2014 REUS sample, BC Hydro estimates the following for Residential Vancouver Island accounts:

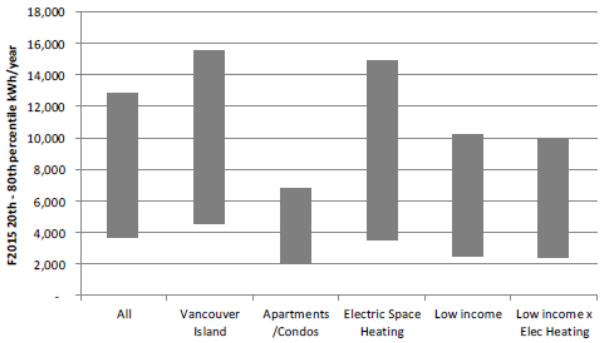


35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.3 Please confirm that all residential customers within the postage stamp area are exposed to the same RIB rates.

RESPONSE:

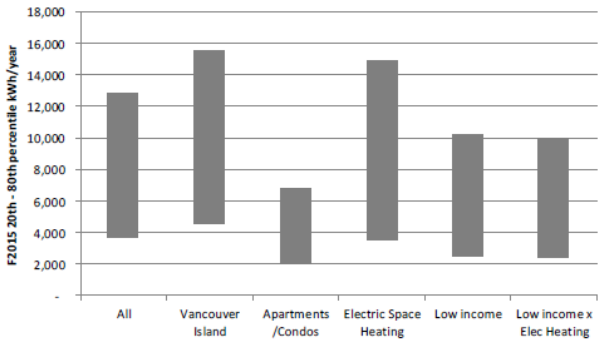
All Residential customers taking service under RS 1101 are exposed to the same RIB rate. Two per cent of Residential customers take service under other rates including RS 1105 (E-Plus rate) and RS 1151 (Exempt Residential Service); in this regard, please refer to Figure 5-1 of Exhibit B-1.

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.4 Approximately how many residential customers does BC Hydro have, within its 'postage stamp area', without access to natural gas in their service area?

RESPONSE:

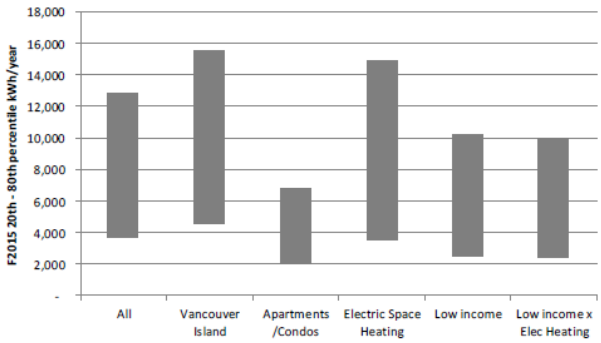
BC Hydro estimates that 3 per cent of its Residential customers are in communities listed in BC Hydro's response to BCUC IR 1.48.2 which do not have access to natural gas.

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.5 Please confirm that those customers without access to natural gas but within the electricity postage stamp area would be exposed to the tier 2 rates for electricity, depending on their choice of electricity consumption for the functions that otherwise would be supplied by a natural gas service.

RESPONSE:

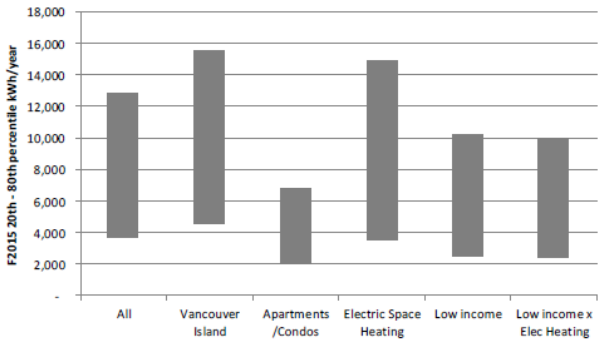
BC Hydro is unable to confirm the statement. Customers may choose fuel sources other than electricity to replace consumption that could otherwise have been served by natural gas. For example, a customer may use propane for space and water heating.

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.6 Is it fair to conclude that, based on the above table, use of electric space heating contributes about an additional 15% to residential consumption?

RESPONSE:

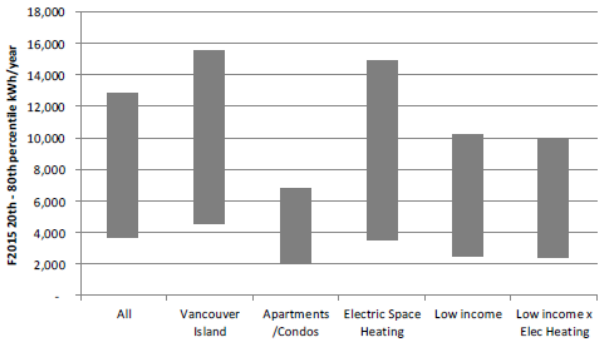
BC Hydro is of the view that there's no single percentage increase that can be used to describe the additional consumption due to electric space heating. Please refer to BC Hydro's response to BCOAPO IR 1.74.1 for an illustration of the annual consumption and bills of the median customers with and without electric space heating, based on the REUS sample.

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.6 Is it fair to conclude that, based on the above table, use of electric space heating contributes about an additional 15% to residential consumption?

1.35.6.1 If not, please provide the approximate average increase, or a range of increases, in consumption that a residential customer with electric space heating would likely have versus a customer that does not.

RESPONSE:

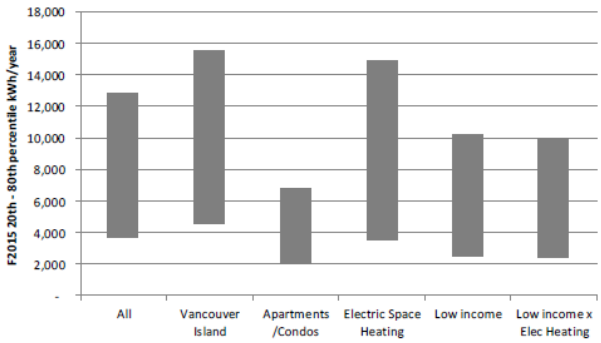
Please refer to BC Hydro's response to CEC IR 1.35.6.

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.7 Please provide the approximate bill increase, or range of increases, that a residential customer with electric space heating would likely experience versus a customer that does not.

RESPONSE:

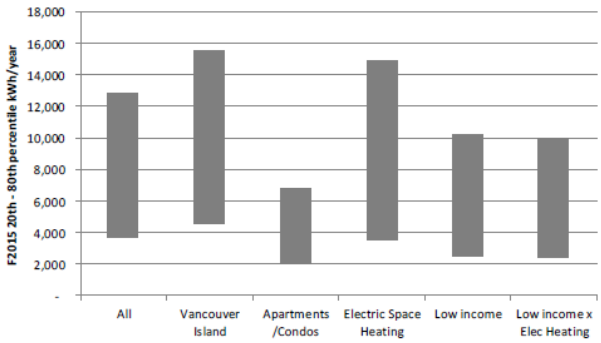
Please refer to BC Hydro's response to CEC IR 1.35.6.

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.8 Please confirm that a customer without access to natural gas would be required to 'trade-off' the costs of electricity heating against that of other fuels such as propane, heating oil or biomass fuels such as wood-burning.

RESPONSE:

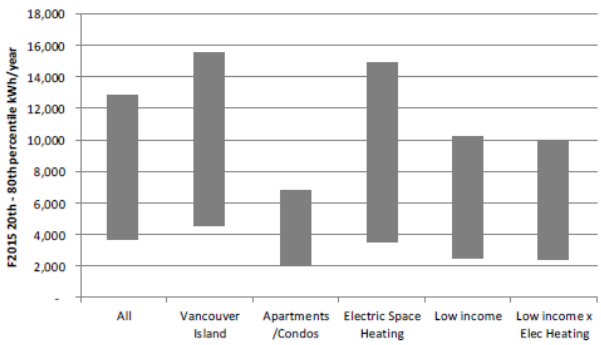
BC Hydro assumes that what is meant by "trade-off the costs of electricity heating against that of other fuels" is that the customer would be required to compare the costs of the various heating sources against one another. BC Hydro cannot confirm this statement as there may be other factors that influence a customer's choice in heating fuel beyond cost (e.g., availability of fuel or ability to retrofit existing systems).

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.8 Please confirm that a customer without access to natural gas would be required to 'trade-off' the costs of electricity heating against that of other fuels such as propane, heating oil or biomass fuels such as wood-burning.

1.35.8.1 If not confirmed, please provide BC Hydro's view of the trade-off customers without access to natural gas for heating experience with respect to their heating options.

RESPONSE:

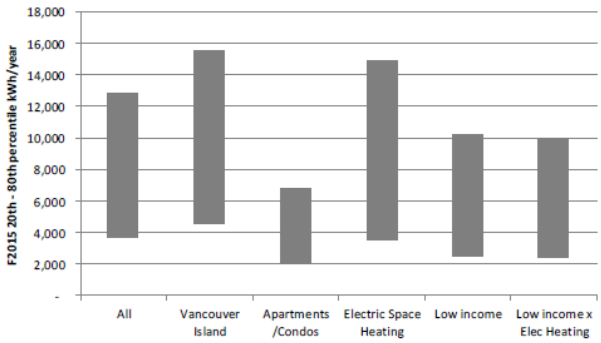
Please refer to BC Hydro's response to CEC IR 1.35.8.

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.9 Please confirm that electricity is a significantly cleaner option than propane, heating oil or the burning of wood.

RESPONSE:

The BC Hydro integrated system is currently 97 per cent clean or renewable. Propane and heating oil have greater GHG emission intensity than BC Hydro's integrated system electricity generation, while the burning of wood is considered by the B.C. Government to be GHG neutral.

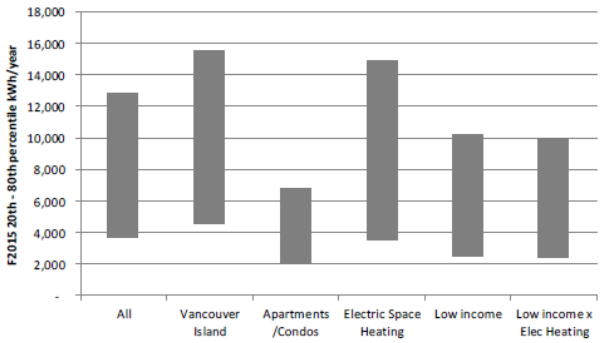
BC Hydro notes that burning wood, heating oil and propane result in the release of Criteria Air Contaminants such as sulphur dioxide, nitrogen dioxide and fine particulate matter.

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.9 Please confirm that electricity is a significantly cleaner option than propane, heating oil or the burning of wood.

1.35.9.1 If not confirmed, please explain why not.

RESPONSE:

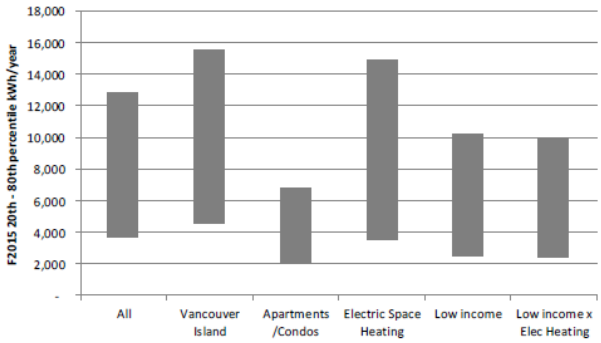
Please refer to BC Hydro's response to CEC IR 1.35.9.

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.10 Please provide BC Hydro's views as to the public interest issues involved in exposing those customers without access to natural gas to tier 2 pricing in their service area vis a vis those customers who do have access to natural gas for heating in their service area.

RESPONSE:

Given the B.C. Government's postage stamp rate-making policy, there is and will only be one Residential default rate. In BC Hydro's view the only two practical alternatives are the RIB rate and a flat rate:

- **The flat rate modelled by BC Hydro for the 2015 RDA has unacceptable bill impacts for most Residential customers. Refer to section 5.3.4.1 of Exhibit B-1 and in particular Figures 5-13 and 5-14; and**

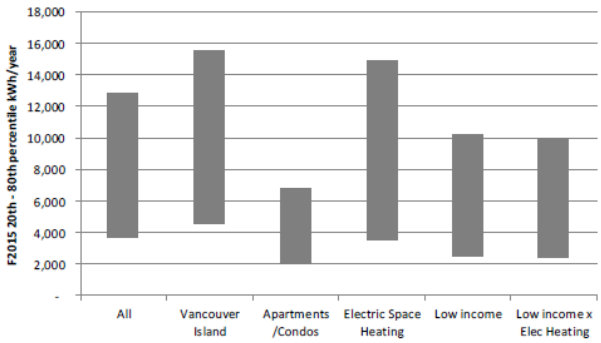
- **The RIB rate is intended to send a price signal to Residential customers that reflects BC Hydro's energy LRMC. BC Hydro believes that the RIB rate is fair, just and not unduly discriminatory whether or not a customer has access to natural gas.**

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.11 What would be the average estimated bill impact if those customers without access to natural gas in their service area were not exposed to the RIB rate?

RESPONSE:

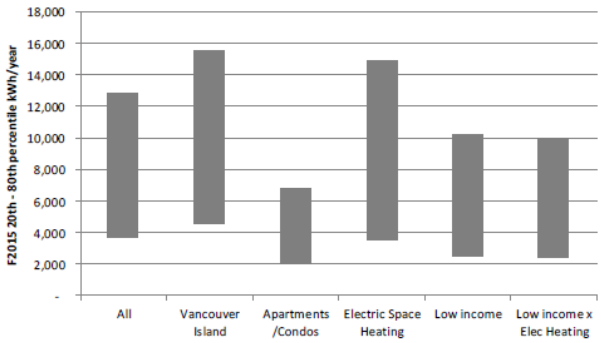
Given the B.C. Government's postage stamp policy, a flat rate would apply to all Residential customers in BC Hydro's service area for purposes of responding to this IR. BC Hydro cannot respond to this IR at this time because it requires a definition of customers without access to natural gas. Assuming the Commission determines the definition of customers without access to natural gas before the end of January 2016, BC Hydro will model the bill impacts on customers without access to natural gas assuming a flat rate structure and provide the result as part of its responses to Round 2 IRs.

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.12 What would be the total reduction in revenues to BC Hydro if those customers without access to natural gas in their service were not exposed to the RIB rate?

RESPONSE:

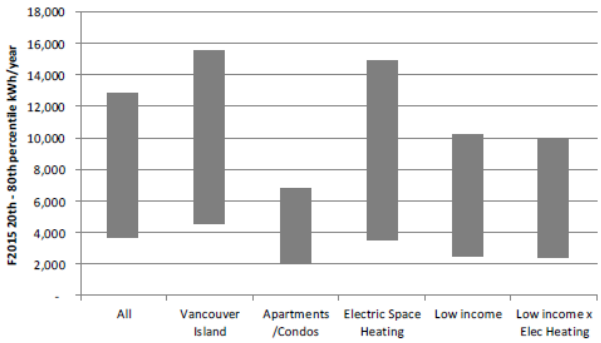
There would be no expected reduction in BC Hydro revenues as rates are set on a revenue neutral basis. As a result, rates for all other Residential customers would increase or decrease to reflect any changes in revenues associated with those customers who moved to an alternative rate such as a flat rate.

35.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-14 and page 1-16

As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.35.13 What would be the average bill impact to other residential customers if those customers without access to natural gas in their service area were not exposed to the RIB rate?

RESPONSE:

Given the B.C. Government's postage stamp policy, a flat rate would apply to all Residential customers in BC Hydro's service area for purposes of responding to this IR. BC Hydro modelled the flat rate bill impacts to Residential customers in Exhibit B-1, section 5.2.4.1. Refer in particular to Exhibit B-1, Figure 5-13.

36.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-18

- Price elasticity is generally larger for customer segments with higher consumption. As discussed in section 5.2.2.2 above, customers living in single family detached homes generally have higher consumption than those living in other dwelling types. The 2013 RIB Evaluation Report finds that customers living in single family detached houses demonstrate higher price responsiveness than customers living in town houses, apartments or mobile homes (2013 RIB Evaluation Report, pages vi, 19). Section 5.2.2.2 also shows that customers with electric heat tend to have higher consumption than those that use other heating fuels. Price elasticity is higher among households with electric heat than those with non-electric heat (2013 RIB Evaluation Report, pages vi, 20); and
- Higher consumption is correlated with both higher awareness of the RIB rate and higher price elasticity; however, no firm conclusions can be drawn about how RIB awareness is related to customer price response (RIB Evaluation Report, pages vii, 28).

1.36.1 Would BC Hydro agree that customers with the lowest levels of consumption such as those living in apartments/condo may have lower price elasticity because they have less opportunity to reduce consumption due to such factors as fewer rooms in which to use heat or light.

RESPONSE:

The 2013 RIB Evaluation found that households with lower residential electricity consumption (1350 kWh - 2400 kWh bi-monthly per customer) show lower price responsiveness (i.e., price elasticity of lower magnitude) than do higher consumption households (2400 kWh and above). In addition, customers living in apartments show lower price responsiveness than customers living in other dwelling types (SFDs, row/townhouses, mobile homes and other). Please refer to Exhibit B-1, Appendix C-3B, pages 131 and 132 of 609.

While the 2013 RIB Evaluation does not explain why apartments have lower price responsiveness than other dwelling types, it does provide evidence that explains why they have lower consumption than other dwelling types: smaller size, lower occupancy, increased proportion of shared walls and higher frequency of central water heating. Please refer to Exhibit B-1, Appendix C-3B, page 134 of 609.

BC Hydro's consultants, E3, prepared a literature review on the relative elasticities of small and large residential customers. Please refer to Exhibit B-1, Appendix D-2.

E3 did not review literature on whether the association between a) lower consumption or apartment living and b) lower price responsiveness is due to the number of rooms available for heating and/or lighting.

36.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-18

- Price elasticity is generally larger for customer segments with higher consumption. As discussed in section 5.2.2.2 above, customers living in single family detached homes generally have higher consumption than those living in other dwelling types. The 2013 RIB Evaluation Report finds that customers living in single family detached houses demonstrate higher price

responsiveness than customers living in town houses, apartments or mobile homes (2013 RIB Evaluation Report, pages vi, 19). Section 5.2.2.2 also shows that customers with electric heat tend to have higher consumption than those that use other heating fuels. Price elasticity is higher among households with electric heat than those with non-electric heat (2013 RIB Evaluation Report, pages vi, 20); and

- Higher consumption is correlated with both higher awareness of the RIB rate and higher price elasticity; however, no firm conclusions can be drawn about how RIB awareness is related to customer price response (RIB Evaluation Report, pages vii, 28).

1.36.1 Would BC Hydro agree that customers with the lowest levels of consumption such as those living in apartments/condo may have lower price elasticity because they have less opportunity to reduce consumption due to such factors as fewer rooms in which to use heat or light.

1.36.1.1 If no, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.36.1.

37.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-18 and page 5-18 and 5-19 to 5-20

- Higher consumption is correlated with both higher awareness of the RIB rate and higher price elasticity; however, no firm conclusions can be drawn about how RIB awareness is related to customer price response (RIB Evaluation Report, pages vii, 28).

- A total of 50 per cent of Residential customers appear to be aware of the RIB rate as of February 2012; and

Residential customer awareness of the RIB rate could be increased. BC Hydro responded that it may be possible to further increase customer awareness but this would come at a cost. Awareness efforts have continued since the October 2008 initial launch by including RIB rate messaging in other communications where appropriate (e.g., Power Smart residential DSM program materials, email correspondence with billing notices). However, a broader marketing campaign would be necessary to ensure that RIB-specific messaging was promoted.[182]

1.37.1 What are the estimated costs of further increasing residential customer awareness of the RIB? Please provide quantification and relate this to the estimated level of awareness that could be achieved at the cost.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.4.1.

37.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-18 and page 5-18 and 5-19 to 5-20

- Higher consumption is correlated with both higher awareness of the RIB rate and higher price elasticity; however, no firm conclusions can be drawn about how RIB awareness is related to customer price response (RIB Evaluation Report, pages vii, 28).

- A total of 50 per cent of Residential customers appear to be aware of the RIB rate as of February 2012; and

Residential customer awareness of the RIB rate could be increased. BC Hydro responded that it may be possible to further increase customer awareness but this would come at a cost. Awareness efforts have continued since the October 2008 initial launch by including RIB rate messaging in other communications where appropriate (e.g., Power Smart residential DSM program materials, email correspondence with billing notices). However, a broader marketing campaign would be necessary to ensure that RIB-specific messaging was promoted.[182]

1.37.2 What, if any, plans does BC Hydro have to raise awareness of the RIB pricing? Please provide an overview with a timeframe of when they will be introduced and the expected costs.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.4.1.

38.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-18 and page 5-23

- The total amount of the household electricity bill serves as the greatest incentive to manage electricity consumption among residential customers, followed by electricity prices.

2. As for conservation savings, a flat rate will likely result in a reduction in conservation because most customers are facing a reduction in their marginal price relative to the RIB rate;
3. Bill impacts are part of the Bonbright customer understanding and acceptance criterion. BC Hydro's primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers. As discussed at Workshop 9a, under a flat rate bills would go up for most customers, including low income customers, while bills would go down for larger consuming residential customers. Figure 5-13 and Figure 5-14, and Table 5-3 and Table 5-4, illustrate the estimated bill impact distribution for flattening of the RIB rate in F2017 (relative to BC Hydro's RIB Pricing Principles):

1.38.1 Please rationalize the three concepts that :

a) the total household electricity bill is a greater triggering factor for conservation than 'electricity prices' ,
b) most customers will see a rate increase and
c) a flat rate will result in a reduction in conservation because most customers are facing a reduction in their marginal price relative to the RIB rate.

RESPONSE:

BC Hydro interprets BCUC IR 1.38.1 to be implying that there is a contradiction between customers responding to electricity bills, rate increases for most customers and overall reduction in conservation, and that one of the three concepts must be false. These statements, however, are all generally correct. This response will elaborate on each concept below.

Concept A

BC Hydro's 2013 RIB Evaluation Report showed that total bill, electricity prices and the RIB rate structure all served as incentives to Residential customers to manage their household's consumption of electricity. Please refer to Exhibit B-1, Appendix C--3B, pages 135 to 140 of 609.

Concept B

To understand concept (b), we can divide the BC Hydro Residential bills into three categories:

1. **Bills where all of the usage is within RIB rate Step 1 (less than or equal to 1,350 kWh in the bi-monthly billing period);**
2. **Bills where the usage is between 1,350 kWh and the range of 2,300 kWh to 14,000 kWh, depending on consumption patterns, where the bill between the status quo RIB rate and flat rate breaks even; and**
3. **Bills where the usage is above the break-even points within the range of 2,300 kWh to 14,000 kWh.**

The bills in category 1 would be subject to only Step 1 prices under the RIB rate, and they would see a price and bill increase under a flat rate relative to the RIB rate.

The bills in category 2 would see overall bill increases if switched to a flat rate because the bill increase of the higher flat rate for usage through 1,350 kWh would be larger than the bill decrease for the lower flat rate for usage above 1,350 kWh.

The bills in category 3 would be lower under a flat rate because these larger customers benefit from the flat energy rate being lower than the RIB Step 2 rate.

Thus, most customers will see an average rate increase under a flat rate because the bills in categories 1 and 2 will all see bill increases. The total number of Residential bills in categories 1 and 2 is larger than the number of bills in the remaining category 3. When aggregated by customer, instead of bills, the number of customers seeing overall bill and average rate increases outnumbers the number of customers that see overall bill and rate decreases.

Concept C

BC Hydro agrees that a flat rate will result in a reduction in conservation because more marginal consumption is exposed to a reduction in marginal price. About 80% of all consumption is exposed to Step 2 prices under the RIB rate (please refer to the Workshop 9b presentation at Appendix C-3B of Exhibit B-1, page 42 of 609). However, it should be noted that it is the amount of marginal consumption exposed to Step 2 prices that actually drives the conservation response, rather than the number of customers. Therefore, a more accurately phrased concept would be: "a flat rate will result in a reduction in conservation because most marginal consumption is facing a reduction in marginal price relative to the RIB rate".

In addition, customers with bills in Step 1 are expected to respond to marginal price increases at a price elasticity of -0.05, while customers with larger bills are expected to respond to marginal price decreases at a price elasticity of -0.10, which is double the response rate of the smaller Step 1 bills. This effect dampens the increased conservation for small customers, compared to the reduced conservation for large customers. This further contributes to an overall reduction in conservation for the residential class as a whole.

Thus, all three of these concepts are generally correct, and there is no conflict between them.

38.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-18 and page 5-23

- The total amount of the household electricity bill serves as the greatest incentive to manage electricity consumption among residential customers, followed by electricity prices.

2. As for conservation savings, a flat rate will likely result in a reduction in conservation because most customers are facing a reduction in their marginal price relative to the RIB rate;
3. Bill impacts are part of the Bonbright customer understanding and acceptance criterion. BC Hydro's primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers. As discussed at Workshop 9a, under a flat rate bills would go up for most customers, including low income customers, while bills would go down for larger consuming residential customers. Figure 5-13 and Figure 5-14, and Table 5-3 and Table 5-4, illustrate the estimated bill impact distribution for flattening of the RIB rate in F2017 (relative to BC Hydro's RIB Pricing Principles):

1.38.1.1 To the extent that conservation is reduced as a result of a flat rate, does the conservation reduction only come from those larger residential customers whose bills would go down? Please explain.

RESPONSE:

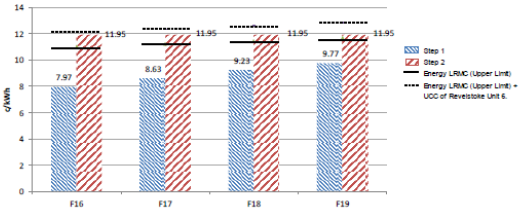
The movement from the RIB rate to a flat rate structure would result in lost conservation from customers with usage that extends past the Step 2 threshold. There could be additional losses in conservation from a perceived de-emphasis on conservation that would be signaled by the elimination of the RIB rate. Such related conservation effects are not explicitly estimated by BC Hydro.

39.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-35 and page 5-19

Option 2 would apply the rate increases to the Step 1 energy rate and basic charge only while holding the Step 2 energy rate at its current level, which results in narrowing the differential between the Step 1 and Step 2 energy rates over time. Under Option 2, the Step 2 energy rate would be approximately equal to the energy LRMC upper limit by F2019, with a forecast loss of conservation in comparison to Option 1. Higher bill impacts for most customers, including low income customers, would also be expected under Option 2. Option 2 is depicted in Figure 5-19.

Figure 5-19 Pricing Principle Option 2, F2017-F2019



Residential customer awareness of the RIB rate could be increased. BC Hydro responded that it may be possible to further increase customer awareness but this would come at a cost. Awareness efforts have continued since the October 2008 initial launch by including RIB rate messaging in other communications where appropriate (e.g., Power Smart residential DSM program materials, email correspondence with billing notices). However, a

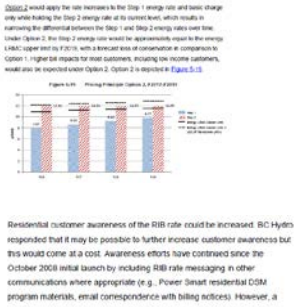
1.39.1 Please provide an overview of any evidence that BC Hydro has with respect to the relationship between the magnitude of the difference between the Step 1 energy rate and the Step 2 energy rate and the responsiveness of customers to the RIB rate?

RESPONSE:

As noted in the 2013 RIB Evaluation Report (Exhibit B-1, Appendix C-3B, page 139 of 609), customers who correctly identified the inclining block rate as the method that BC Hydro uses for charging their household's consumption of energy and who said it serves as an incentive to manage their use of it were asked how the rate acts as a motivator. Among these customers, the single largest segment – 33 per cent – reported that the difference between the Step 1 and Step 2 prices acts as an incentive to their household to manage its consumption of electricity.

39.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-35 and page 5-19



Option 2 would apply the rate increases to the Step 1 energy rate and basic charge only while holding the Step 2 energy rate at its current level, which results in narrowing the differential between the Step 1 and Step 2 energy rates over time. Under Option 2, the Step 2 energy rate would be approximately equal to the energy LRMC upper limit by F2019, with a forecast loss of conservation in comparison to Option 1. Higher bill impacts for most customers, including low income customers, would also be expected under Option 2. Option 2 is depicted in Figure 5-19.

Figure 5-19 Pricing Principle Option 2, F2017-F2019

Residential customer awareness of the RIB rate could be increased. BC Hydro responded that it may be possible to further increase customer awareness but this would come at a cost. Awareness efforts have continued since the October 2008 initial launch by including RIB rate messaging in other communications where appropriate (e.g., Power Smart residential DSM program materials, email correspondence with billing notices). However, a

1.39.2 Please confirm that costs invested in creating an improvement in customer awareness and understanding of the RIB rate would be better served with a larger discrepancy between the Step 1 and Step 2 rates.

RESPONSE:

BC Hydro cannot confirm that an unspecified increase in the existing differential between Step 1 and Step 2 (currently about 50 per cent), combined with an undetermined expenditure aimed at increasing customer understanding, will result in increased customer understanding of the RIB rate. Please refer to the Workshop 9a/9b consideration memo, Exhibit B-1, Appendix C-3B, page 369 of 609 which sets out BC Hydro's jurisdictional assessment that the existing RIB rate Step 1/Step 2 differential is within the range of differentials for surveyed U.S. and Canadian residential two step inclining block rates.

To be responsive, BC Hydro offers the following:

- **BC Hydro found through assessing RIB rate F2017-F2019 pricing principle Option 2, which narrows the existing differential between Step 1 and Step 2, that narrowing the Step 1/Step 2 differential can result in a loss of conservation. BC Hydro believes that conservation would be increased by higher Step 2 prices and by increased customer understanding and awareness of that Step 2 price. However, it is the magnitude of the Step 2 price, rather than the differential, that should be the conservation driver for an informed customer; and**

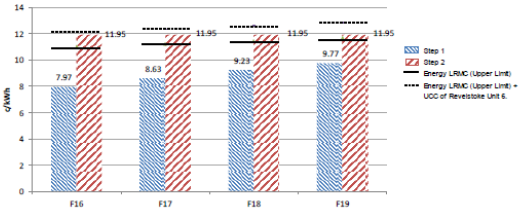
- **Costs are not an agent that can be better or worse served by any action. Furthermore, customers that have a better understanding of their applicable rates will be in a better position to make fully informed consumption decisions. The customers would therefore be better served by increased understanding, regardless of the Step 1/Step 2 differential.**

39.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-35 and page 5-19

Option 2 would apply the rate increases to the Step 1 energy rate and basic charge only while holding the Step 2 energy rate at its current level, which results in narrowing the differential between the Step 1 and Step 2 energy rates over time. Under Option 2, the Step 2 energy rate would be approximately equal to the energy LRMC upper limit by F2019, with a forecast loss of conservation in comparison to Option 1. Higher bill impacts for most customers, including low income customers, would also be expected under Option 2. Option 2 is depicted in Figure 5-19.

Figure 5-19 Pricing Principle Option 2, F2017-F2019



Residential customer awareness of the RIB rate could be increased. BC Hydro responded that it may be possible to further increase customer awareness but this would come at a cost. Awareness efforts have continued since the October 2008 initial launch by including RIB rate messaging in other communications where appropriate (e.g., Power Smart residential DSM program materials, email correspondence with billing notices). However, a

1.39.2 Please confirm that costs invested in creating an improvement in customer awareness and understanding of the RIB rate would be better served with a larger discrepancy between the Step 1 and Step 2 rates.

1.39.2.1 If not confirmed, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.39.2.

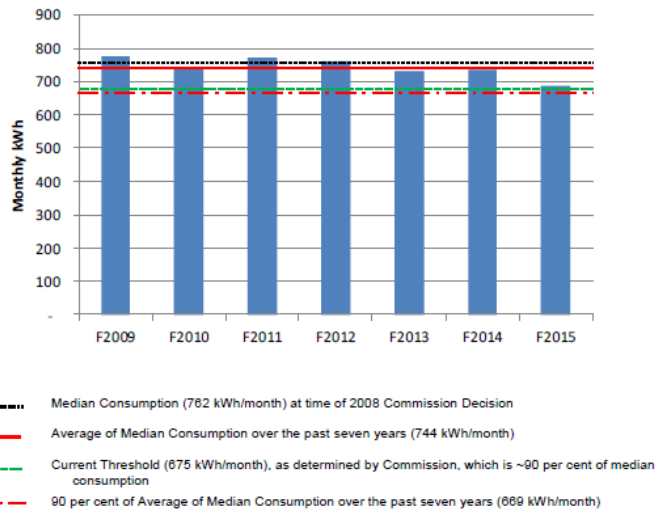
40.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-43

5.2.5.4 Step 1/Step 2 Threshold

BC Hydro proposes no change to the existing Step 1/Step 2 threshold. The current threshold of 675 kWh per month reflects typical residential use, as it still represents approximately 90 per cent of the monthly median consumption given seven years of consumption data to date. This is shown by Figure 5-25 and Table 5-11 below.

Figure 5-25 Median Consumption per Month



1.40.1 Why is the average consumption over the last 7 years the appropriate period to use, when the consumption appears to be clearly declining in recent years?

RESPONSE:

Exhibit B-1, Figure 5-25 and Table 5-11, extend on the graphic presented at Workshop 3, as shown on Exhibit B-1, Appendix C-3A, page 59 of 184. The average was presented as a summary statistic at the workshop, and in Exhibit B-1 it is re-computed using the latest data available.

BC Hydro is of the view that both the median consumption of individual years provided and the average statistic of all the years are useful in the assessment of the current RIB rate Step 1/Step 2 threshold. These values show that the Step 1/Step 2 threshold remains reasonable.

Exhibit B-1, Figure 5-25 and Table 5-11 show that the median consumption fluctuates modestly from year to year. A distinct trend showing a permanent and substantive year-over-year decline is not evident from the results shown.

41.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1 page 5-45

Table 5-11 Median Consumption per Month

	Monthly Median (kWh)*	90% of the Monthly Median (kWh)
F2009	777	699
F2010	739	665
F2011	772	695
F2012	762	686
F2013	733	660
F2014	734	661
F2015	689	620
Seven-Year Average	744	669
Threshold set from 2008 Commission Decision, page 107	Based on 762	675

* Computed based on the same methodology as the 2008 RIB Application which includes all customers in RS 1101 with consumption between 1,200 kWh/year and 120,000 kWh/year. The monthly median of each year is computed as the median annual consumption divided by 12.

1.41.1 Please confirm that, or otherwise revise, the calculation of threshold based on 90% of the monthly median consumption using the last five years of data would be 585 KWh/month?

RESPONSE:

Not confirmed. The average of the "90 per cent of median" over the last five years of data is 664 kWh/month. It is computed by averaging F2011 to F2015 values from the third column of Exhibit B-1, Table 5-11, titled "90% of the monthly median (kWh)" as follows:

664 kWh/month = (695 + 686 + 660 + 661 + 620)/5

41.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1 page 5-45

Table 5-11 Median Consumption per Month

	Monthly Median (kWh)*	90% of the Monthly Median (kWh)
F2009	777	699
F2010	739	665
F2011	772	695
F2012	762	686
F2013	733	660
F2014	734	661
F2015	689	620
Seven-Year Average	744	669
Threshold set from 2008 Commission Decision, page 107	Based on 762	675

* Computed based on the same methodology as the 2008 RIB Application which includes all customers in RS 1101 with consumption between 1,200 kWh/year and 120,000 kWh/year. The monthly median of each year is computed as the median annual consumption divided by 12.

1.41.2 Please confirm that, or otherwise revise, the calculation of threshold based on 90% of the monthly median consumption using the last three years of data would be 597 KWh/month.

RESPONSE:

Not confirmed. The average of the "90 per cent of median" over the last three years of data is 647 kWh/month. It is computed by averaging F2013 to F2015 values from the third column of Exhibit B-1, Table 5-11, titled "90 per cent of the monthly median (kWh)" as follows:

647 kWh/month = (660 + 661 + 620)/3

42.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-45

Figure 5-26 Step 2 Exposure, all Accounts

1.42.1 Please revise the chart using 90% of the monthly median consumption using the last five years of data would be 597 KWh/month.

RESPONSE:

As shown in BC Hydro's response to CEC IR 1.41.1, 90 per cent of the median consumption calculated using the last five years of data is not 597 kWh/month; rather, the average of the "90 per cent of median" over the last five years of data is 664 kWh/month. Given the small difference between the 664 and 675 KWh/month thresholds, the results would be similar.

42.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-45

Figure 5-26 Step 2 Exposure, all Accounts

1.42.2 Please revise the chart using 90% of the monthly median consumption using the last three years of data would be 597 KWh/month.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.42.1.

43.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-49

RS 1105 energy rate for F2016 is 5.22 cents/kWh and there is no basic charge. There are approximately 7,500 Residential E-Plus customers. Residential E-Plus customers represent a small portion of the Residential customer revenues (approximately $4.7 million of $1.9 billion (F2014)).

E-Plus rates were introduced in 1987 to residential and commercial customers. The purpose of the rates was to market surplus energy that would have been spilled because at the time consistent access to the spot market was not available. As part of the 2007 RDA Decision,[199] the Commission approved restricting the ability to transfer the E-Plus rate to a new customer by amending the RS 1105 Availability clause to state that the E-Plus rate is available "only in Premises where there has been no change in customer since April 1, 2008".

The 2007 RDA Decision contains Residential E-Plus-related directions relevant to or to be addressed as part of the 2015 RDA, summarized in Table 5-12.

1.43.1 Are there any commercial E-Plus remaining?

RESPONSE:

As of August 2015 there were approximately 225 commercial E-Plus customers.

43.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-49

RS 1105 energy rate for F2016 is 5.22 cents/kWh and there is no basic charge. There are approximately 7,500 Residential E-Plus customers. Residential E-Plus customers represent a small portion of the Residential customer revenues (approximately $4.7 million of $1.9 billion (F2014)).

E-Plus rates were introduced in 1987 to residential and commercial customers. The purpose of the rates was to market surplus energy that would have been spilled because at the time consistent access to the spot market was not available. As part of the 2007 RDA Decision,[199] the Commission approved restricting the ability to transfer the E-Plus rate to a new customer by amending the RS 1105 Availability clause to state that the E-Plus rate is available "only in Premises where there has been no change in customer since April 1, 2008".

The 2007 RDA Decision contains Residential E-Plus-related directions relevant to or to be addressed as part of the 2015 RDA, summarized in Table 5-12.

1.43.1 Are there any commercial E-Plus remaining?

1.43.1.1 If yes, how many E-Plus commercial accounts are there?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.43.1.

43.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-49

RS 1105 energy rate for F2016 is 5.22 cents/kWh and there is no basic charge. There are approximately 7,500 Residential E-Plus customers. Residential E-Plus customers represent a small portion of the Residential customer revenues (approximately $4.7 million of $1.9 billion (F2014)).

E-Plus rates were introduced in 1987 to residential and commercial customers. The purpose of the rates was to market surplus energy that would have been spilled because at the time consistent access to the spot market was not available. As part of the 2007 RDA Decision,[199] the Commission approved restricting the ability to transfer the E-Plus rate to a new customer by amending the RS 1105 Availability clause to state that the E-Plus rate is available "only in Premises where there has been no change in customer since April 1, 2008".

The 2007 RDA Decision contains Residential E-Plus-related directions relevant to or to be addressed as part of the 2015 RDA, summarized in Table 5-12.

1.43.1 Are there any commercial E-Plus remaining?

1.43.1.2 If not, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.43.1.

44.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-52

5.3.4 BC Hydro Proposal and Stakeholder Engagement

As described in section 2.2.3.5 of the Application, BC Hydro engaged E-Plus customers through a letter dated February 24, 2015 seeking feedback on the E-Plus rate as well as holding two open houses held in Nanaimo and Victoria on April 1 and April 2, 2015. BC Hydro received approximately 3,700 Residential E-Plus customer responses to the February 24, 2015 letter (about 45 per cent of the total number of Residential E-Plus customers). The vast majority of respondents support Option 1 for a number of reasons including:

1. The E-Plus rate is a contract between BC Hydro and the customer (37 per cent of comments);
2. Investments in back-up systems were made in good faith (36 per cent of comments);
3. Electricity affordability (36 per cent); and
4. The closed rate will end under attrition given the generally older age of E-Plus customers (21 per cent).

1.44.1 Are the E-Plus customers predominantly on Vancouver Island?

RESPONSE:

Yes, about 70 per cent of Residential E-Plus accounts are on Vancouver Island.

44.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-52

5.3.4 BC Hydro Proposal and Stakeholder Engagement

As described in section 2.2.3.5 of the Application, BC Hydro engaged E-Plus customers through a letter dated February 24, 2015 seeking feedback on the E-Plus rate as well as holding two open houses held in Nanaimo and Victoria on April 1 and April 2, 2015. BC Hydro received approximately 3,700 Residential E-Plus customer responses to the February 24, 2015 letter (about 45 per cent of the total number of Residential E-Plus customers). The vast majority of respondents support Option 1 for a number of reasons including:

1. The E-Plus rate is a contract between BC Hydro and the customer (37 per cent of comments);
2. Investments in back-up systems were made in good faith (36 per cent of comments);
3. Electricity affordability (36 per cent); and
4. The closed rate will end under attrition given the generally older age of E-Plus customers (21 per cent).

1.44.1 Are the E-Plus customers predominantly on Vancouver Island?

1.44.1.1 If so, please explain why this situation has developed.

RESPONSE:

When it was introduced, the E-Plus program was specifically targeted to SFDs and duplexes in BC Hydro's integrated system that were not heated by electricity or natural gas. Vancouver Island was identified as the prime market area with nearly 50 per cent of the potential customers as so defined.

44.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-52

5.3.4 BC Hydro Proposal and Stakeholder Engagement

As described in section 2.2.3.5 of the Application, BC Hydro engaged E-Plus customers through a letter dated February 24, 2015 seeking feedback on the E-Plus rate as well as holding two open houses held in Nanaimo and Victoria on April 1 and April 2, 2015. BC Hydro received approximately 3,700 Residential E-Plus customer responses to the February 24, 2015 letter (about 45 per cent of the total number of Residential E-Plus customers). The vast majority of respondents support Option 1 for a number of reasons including:

1. The E-Plus rate is a contract between BC Hydro and the customer (37 per cent of comments);
2. Investments in back-up systems were made in good faith (36 per cent of comments);
3. Electricity affordability (36 per cent); and
4. The closed rate will end under attrition given the generally older age of E-Plus customers (21 per cent).

1.44.1 Are the E-Plus customers predominantly on Vancouver Island?

1.44.1.2 If no, why did BC Hydro only hold open houses in Vancouver Island?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.44.1.

45.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-50 and page 5-53 and page 5-55 and page 5-56

BC Hydro has never interrupted E-Plus load. Special Condition 1 of RS 1105 restricts BC Hydro's right to interrupt the supply of electricity; there must be a "surplus hydro energy" and "the service cannot be provided economically from other energy sources". This is very different language than the typical interruptible rate provisions whereby BC Hydro will only provide service when it has available energy and capacity to do so.

- Ending the E-Plus program would impose considerable financial hardship on users, almost all of whom are seniors;

- The proposed changes to Special Condition 1 will allow for the Residential E-Plus rate to be practically interruptible. BC Hydro proposes the following language for Special Condition 1 as shown on the amended RS 1105 in Appendix F-1D: "*BC Hydro will provide electricity under this rate schedule only to the extent that it has energy and capacity to do so. BC Hydro may, at any time and from time to time, interrupt the supply of electricity under this rate schedule where BC Hydro does not have sufficient energy or capacity*". This language aligns with interruption provisions in the recently Commission approved Shore Power Rates.[223] The proposed language is also generally consistent with Commission Order No. G-37-90[224] which approved interruption criteria for E-Plus service as follows: "*BC Hydro may, at any time and from time to time, interrupt the supply of energy under this Rate Schedule*". This point is expanded on in BC Hydro's response to BCSEA written question 1.6 provided in Attachment 6 to the Workshop 9a/9b consideration memo at Appendix C-3B.

In summary, Option 3 ensures that customers who use the E-Plus rate would continue to receive the current discount, while also ensuring that the rate is truly interruptible and serves a useful function as was intended when the discount was offered.

ahead" (refer to section 7.3.2 of the Application for additional detail). BC Hydro proposes the following as business practices: (i) the issuance of a 'seasonal notice' each year prior to the November-February winter months reminding Residential E-Plus customers that they are served on an interruptible rate. This seasonal notice would be given to all Residential E-Plus customers through auto-dialer, e-mail or letter; (ii) up to one week's notice that an interruption event is likely to occur. This notice would happen through auto-dialer, e-mail or letter. The interruption itself would occur by manual or automatic means or by written notice as set in Special Condition 3 of RS 1105.

1.45.1 While the proposed changes to Special Condition 1 would allow for the E-Plus rate to be practically interruptible and align with language in the Shore Power Rates, is it likely that the E-Plus service will ever actually experience an interruption?

RESPONSE:

BC Hydro will provide electricity under the proposed Residential E-Plus rate (RS 1105) amendments "only to the extent that it has energy and capacity to do". The timing of the need for capacity (either operational or planning) would guide any decision by BC Hydro to test Residential E-Plus interruption assuming the Commission approves the RS 1105 amendments.

Please also refer to BC Hydro's response to BCUC IR 1.43.1.

45.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-50 and page 5-53 and page 5-55 and page 5-56

BC Hydro has never interrupted E-Plus load. Special Condition 1 of RS 1105 restricts BC Hydro's right to interrupt the supply of electricity; there must be a "surplus hydro energy" and "the service cannot be provided economically from other energy sources". This is very different language than the typical interruptible rate provisions whereby BC Hydro will only provide service when it has available energy and capacity to do so.

- Ending the E-Plus program would impose considerable financial hardship on users, almost all of whom are seniors;

- The proposed changes to Special Condition 1 will allow for the Residential E-Plus rate to be practically interruptible. BC Hydro proposes the following language for Special Condition 1 as shown on the amended RS 1105 in Appendix F-1D: "*BC Hydro will provide electricity under this rate schedule only to the extent that it has energy and capacity to do so. BC Hydro may, at any time and from time to time, interrupt the supply of electricity under this rate schedule where BC Hydro does not have sufficient energy or capacity*". This language aligns with interruption provisions in the recently Commission approved Shore Power Rates.[203] The proposed language is also generally consistent with Commission Order No. G-37-90[204] which approved interruption criteria for E-Plus service as follows: "*BC Hydro may, at any time and from time to time, interrupt the supply of energy under this Rate Schedule*". This point is expanded on in BC Hydro's response to BCSEA written question 1.6 provided in Attachment 6 to the Workshop 9a/9b consideration memo at Appendix C-3B.

In summary, Option 3 ensures that customers who use the E-Plus rate would continue to receive the current discount, while also ensuring that the rate is truly interruptible and serves a useful function as was intended when the discount was offered.

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1.45.1 While the proposed changes to Special Condition 1 would allow for the E-Plus rate to be practically interruptible and align with language in the Shore Power Rates, is it likely that the E-Plus service will ever actually experience an interruption?

1.45.1.1 If yes, how often is such an interruption likely to occur?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.45.1.

45.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-50 and page 5-53 and page 5-55 and page 5-56

BC Hydro has never interrupted E-Plus load. Special Condition 1 of RS 1105 restricts BC Hydro's right to interrupt the supply of electricity; there must be a "surplus hydro energy" and "the service cannot be provided economically from other energy sources". This is very different language than the typical interruptible rate provisions whereby BC Hydro will only provide service when it has available energy and capacity to do so.

- Ending the E-Plus program would impose considerable financial hardship on users, almost all of whom are seniors;

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In summary, Option 3 ensures that customers who use the E-Plus rate would continue to receive the current discount, while also ensuring that the rate is truly interruptible and serves a useful function as was intended when the discount was offered.

ahead" (refer to section 7.3.2 of the Application for additional detail). BC Hydro proposes the following as business practices: (i) the issuance of a 'seasonal notice' each year prior to the November-February winter months reminding Residential E-Plus customers that they are served on an interruptible rate. This seasonal notice would be given to all Residential E-Plus customers through auto-dialer, e-mail or letter; (ii) up to one week's notice that an interruption event is likely to occur. This notice would happen through auto-dialer, e-mail or letter. The interruption itself would occur by manual or automatic means or by written notice as set in Special Condition 3 of RS 1105.

1.45.1 While the proposed changes to Special Condition 1 would allow for the E-Plus rate to be practically interruptible and align with language in the Shore Power Rates, is it likely that the E-Plus service will ever actually experience an interruption?

1.45.1.2 If yes, would customers always receive a notice that an interruption would occur, or could this occur with no notice period at all?

RESPONSE:

With respect to notice periods, please refer to BC Hydro's response to BCUC IR 1.43.1.

46.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-58

> In the context of *UCA* sections 58 to 61 rate setting, low income rates are likely to be seen as unduly preferential to low-income customers or unduly discriminatory to the remaining customers who subsidize those rates because the low income rate would be based on the personal characteristics of the customer, divorced from the cost to deliver electricity to the premises. BC Hydro outlined this position at Workshops 1, 3 and 9a, and section 2.1.2 of the Workshop 3 consideration memo (found at Appendix C3-A).
>
> This position accords with the majority of Canadian electric utilities and utility commissions, where cost-based ratemaking is the most widely-used standard for evaluating whether rates are 'fair, just and not unduly discriminatory'. Canadian electric utilities typically offer targeted low income DSM programs, as opposed to low income rates:

1.46.1 Please provide BC Hydro's views as to a % difference that would constitute 'unduly preferential' to any group of customers.

RESPONSE:

As noted in Table 2-7 of Exhibit B-1 under the Bonbright avoid undue discrimination criterion, the meaning of undue discrimination is a matter of the Commission's opinion. There is no 'one size fits' all formulae or percentage difference that would constitute unduly discriminatory or unduly preferential:

- **Also reflected in Table 2-7 is BC Hydro's view that undue discrimination refers to price discrimination practices that are not based on classification of customers in terms of differences in cost of service. It is also BC Hydro's view that the Commission adheres to cost of service ratemaking. For example, in the Commission's *Reasons for Decision for Commission Order No. G-27-93* regarding BC Hydro's Power Purchase Agreement with what was then West Kootenay Power Ltd. (now FortisBC), the Commission stated: "This Commission adheres to the general principle that it should diverge from cost-based principles of ratemaking only with extreme caution" (page 34) (copy available at http://www.ordersdecisions.bcuc.com/bcuc/decisions/en/111834/1/document.do);**

- **Court findings of undue discrimination are tied to whether the service is offered or provided under substantially similar circumstances, i.e., if there are substantially different circumstances, substantially different rates may be justified.**

Please also refer to BC Hydro's responses to BCOAPO IR 1.98.1 and COPE 378 IR 1.12.1.

46.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-58

In the context of *UCA* sections 58 to 61 rate setting, low income rates are likely to be seen as unduly preferential to low-income customers or unduly discriminatory to the remaining customers who subsidize those rates because the low income rate would be based on the personal characteristics of the customer, divorced from the cost to deliver electricity to the premises. BC Hydro outlined this position at Workshops 1, 3 and 9a, and section 2.1.2 of the Workshop 3 consideration memo (found at Appendix C3-A).

This position accords with the majority of Canadian electric utilities and utility commissions, where cost-based ratemaking is the most widely-used standard for evaluating whether rates are 'fair, just and not unduly discriminatory'. Canadian electric utilities typically offer targeted low income DSM programs, as opposed to low income rates:

1.46.2 Please confirm that there is considerable variation in the cost to deliver electricity to different premises between geographic regions, housing types, urban density and many other factors influencing costs which are absorbed in postage stamp rates.

RESPONSE:

Confirmed with respect to geographic regions.

46.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-58

In the context of *UCA* sections 58 to 61 rate setting, low income rates are likely to be seen as unduly preferential to low-income customers or unduly discriminatory to the remaining customers who subsidize those rates because the low income rate would be based on the personal characteristics of the customer, divorced from the cost to deliver electricity to the premises. BC Hydro outlined this position at Workshops 1, 3 and 9a, and section 2.1.2 of the Workshop 3 consideration memo (found at Appendix C3-A).

This position accords with the majority of Canadian electric utilities and utility commissions, where cost-based ratemaking is the most widely-used standard for evaluating whether rates are 'fair, just and not unduly discriminatory'. Canadian electric utilities typically offer targeted low income DSM programs, as opposed to low income rates:

1.46.2 Please confirm that there is considerable variation in the cost to deliver electricity to different premises between geographic regions, housing types, urban density and many other factors influencing costs which are absorbed in postage stamp rates.

1.46.2.1 If confirmed, please confirm that the principle of cost-causation is frequently subordinated to the greater public interest perceived in having postage stamp rates.

RESPONSE:

Confirmed with respect to the assertion in CEC IR 1.46.2 that there is considerable variation in the cost to deliver electricity to different premises in the different geographic regions that make up BC Hydro's service area.

With respect to CEC IR 1.46.2.1, as described in section 2.2.2.1 of Exhibit B-1, postage stamp rate making is B.C. Government policy.

47.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-65

Disclosure of Total Household Income - Total household income is the most essential parameter needed to classify a customer household in the REUS as possibly being low income. When a missing value occurs on this parameter, the customer household has to be either left as unclassified in their low income status or other secondary information has to be leveraged to make an informed classification. In this case, the mean and median household income levels for the household's postal code area together with the area's incidence of low income are taken into account to inform the decision on the low income status. For example, if the mean and median income levels for the postal code area are $65,000, and the incidence of low income in that neighbourhood is say 2 per cent, then the household in question has a very low probability of actually being of low income status. Note that in this case, $65,000 is greater than even the largest of the LICO thresholds.

1.47.1 Please confirm that a low income household can also be 'asset rich' such as in a situation in which a retired party is living on savings, but has significant debt-free assets.

RESPONSE:

BC Hydro has no information as to what customers may or may not be "asset rich" as defined in the IR (significant debt free assets).

47.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-65

Disclosure of Total Household Income - Total household income is the most essential parameter needed to classify a customer household in the REUS as possibly being low income. When a missing value occurs on this parameter, the customer household has to be either left as unclassified in their low income status or other secondary information has to be leveraged to make an informed classification. In this case, the mean and median household income levels for the household's postal code area together with the area's incidence of low income are taken into account to inform the decision on the low income status. For example, if the mean and median income levels for the postal code area are $65,000, and the incidence of low income in that neighbourhood is say 2 per cent, then the household in question has a very low probability of actually being of low income status. Note that in this case, $65,000 is greater than even the largest of the LICO thresholds.

1.47.2 If confirmed, does BC Hydro have any plans to assess the affordability of electricity service based on assets?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.47.1.

47.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-65

Disclosure of Total Household Income - Total household income is the most essential parameter needed to classify a customer household in the REUS as possibly being low income. When a missing value occurs on this parameter, the customer household has to be either left as unclassified in their low income status or other secondary information has to be leveraged to make an informed classification. In this case, the mean and median household income levels for the household's postal code area together with the area's incidence of low income are taken into account to inform the decision on the low income status. For example, if the mean and median income levels for the postal code area are $65,000, and the incidence of low income in that neighbourhood is say 2 per cent, then the household in question has a very low probability of actually being of low income status. Note that in this case, $65,000 is greater than even the largest of the LICO thresholds.

1.47.2 If confirmed, does BC Hydro have any plans to assess the affordability of electricity service based on assets?

1.47.2.1 If yes, please identify any plans BC Hydro has to assess affordability from an asset perspective.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.47.1.

48.0 D. Chapter 5 – Residential Rate Design

Reference: Exhibit B-1, page 5-69

- Electricity consumption by housing type within region. Due primarily to the fact that they rely on electricity for space heating, residential customers on Vancouver Island lead all four regions in average annual consumption at 11,776 kWh. Average household consumption was higher in the Southern Interior (10,211 kWh) and the North (9,894 kWh) than it was in the Lower Mainland (8,634 kWh), most likely due to the relatively heavier electrical demand for space heating and space cooling in those regions (2014 REUS, page 233).

1.48.1 Why do residential customers on Vancouver Island rely primarily on electricity for space heating? Please explain.

RESPONSE:

There is a greater reliance on electric heating on Vancouver Island due to the fact that natural gas was not available on Vancouver Island until 1991. As a result, other fuel sources such as heating oil and electricity were used for space heating.

49.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-8

> BC Hydro proposes maintaining the existing SGS rate structure of a flat energy rate and a basic charge. BC Hydro seeks approval of a one-time increase to the RS 13xx basic charge to 45 per cent recovery of customer-related costs attributable to the SGS class in the F2016 COS study, and a one-time offsetting reduction of the energy rate, to maintain forecast revenue neutrality based on the SGS revenue target calculated using any applicable rate increases arising from the F2017 RRA. The proposal results in the following illustrative SGS pricing assuming the F2018 rate cap increase of 3.5 per cent: a flat energy rate for all kWh of approximately 11.39 cents/kWh and a basic charge of approximately 33.12 cents/day (F2018).

1.49.1 Please confirm that the increase in basic charge recovery is related to customer costs only and is not related to any demand costs, which are all subsumed in the SGS energy charge.

RESPONSE:

Confirmed.

49.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-8

> BC Hydro proposes maintaining the existing SGS rate structure of a flat energy rate and a basic charge. BC Hydro seeks approval of a one-time increase to the RS 13xx basic charge to 45 per cent recovery of customer-related costs attributable to the SGS class in the F2016 COS study, and a one-time offsetting reduction of the energy rate, to maintain forecast revenue neutrality based on the SGS revenue target calculated using any applicable rate increases arising from the F2017 RRA. The proposal results in the following illustrative SGS pricing assuming the F2018 rate cap increase of 3.5 per cent: a flat energy rate for all kWh of approximately 11.39 cents/kWh and a basic charge of approximately 33.12 cents/day (F2018).

1.49.2 Please describe the demand related costs for SGS as a percentage of the total SGS energy revenue (BCUC IR -53) in the F2016 COS and provide the absolute dollar amount being used.

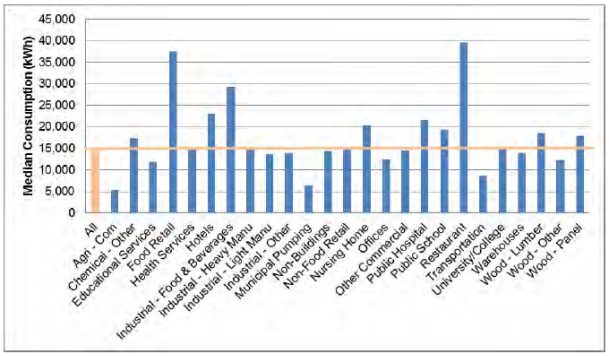
RESPONSE:

Demand-related costs assigned to the SGS class in the F2016 COS amount to $182.7 million, which represent about 49.7 per cent of the total costs assigned to the SGS class (which amount to $367.8 million). Please also refer to BC Hydro's response to BCUC IR 1.53.1.

50.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-9

11 **Figure 6-3 Median SGS Consumption by Site Type**



1.50.1 Please confirm that for each of the median values shown above there would be a significant distribution of the SGS customers on either side of the median value and that this in addition to the data shown in Figure 6-3 is part of the information that leads BC Hydro to conclude that the heterogeneity of the rate class is too diverse to provide a single rate structure solution for providing appropriate price signals as efficiency incentives.

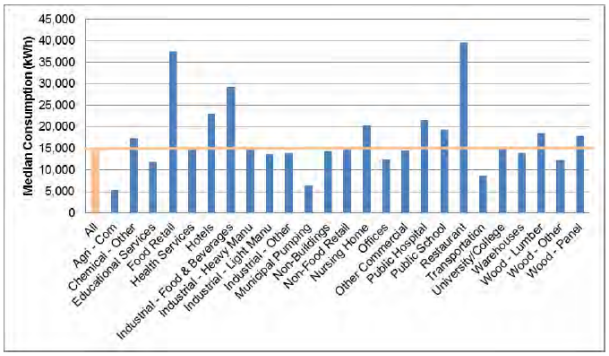
RESPONSE:

The range of the distribution of the entire class, inclusive of all site types, has been discussed in Workshop 8a, which is shown on Exhibit B-1, Appendix C-4A, page 68 of 813. The intent of Exhibit B-1, Figure 6-3 is to show that the diverse range of consumption of the class may in part be due to the different site types. BC Hydro is of the view that an inclining block rate structure with a fixed threshold like the RIB rate is inappropriate for this class due to the heterogeneity and large range of consumptions.

50.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-9

11 **Figure 6-3 Median SGS Consumption by Site Type**



1.50.2 To the extent that BC Hydro has the statistical measure of the dispersion of the distribution around the median values could BC Hydro please provide that as well?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.50.1.

51.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-11

> SGS demand charge would also require a demand meter which not all SGS customers have. The requirement for a demand meter on all SGS customers makes the demand charge less practical and cost-effective to administer.

1.51.1 Please confirm that virtually all SGS customers have BC Hydro's SMI smart meters and that these meters can record the customer demand for energy over the particular monitored measurement interval.

RESPONSE:

The majority of SGS customers have a smart meter installed. Demand can be calculated using the hourly interval data from energy (non-demand) smart meters but significant data and comparative analysis would be required and BC Hydro would not be able to use the calculated demand for billing purposes.

52.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-11

> At Workshop 11a, BC Hydro indicated that no SGS rate structure issues had been identified through the 2015 RDA stakeholder engagement process. There was general agreement among stakeholders that there is not a strong basis to depart from the existing SGS rate structure.

1.52.1 Please confirm that while a flat rate is preferred as the base rate for SGS by general agreement among stakeholders and BC Hydro that this is applicable to Module 1 and that BC Hydro has indicated in the consultation process that it will be open to discussing alternative options for providing incentives in Module 2.

RESPONSE:

BC Hydro committed to engaging with stakeholders to explore optional rates for the General Service and Residential rate classes as part of RDA Module 2.

53.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-10 & 6-14

Table 6-2 Alternative SGS Pricing

Pricing Element (F2017)	BC Hydro Proposal (Increase basic charge to 45% of customer-related costs)	Status Quo
Energy rate (cents/kWh)	11.01	11.16
Basic charge (cents/day)	32.00	23.47

Table 6-3 Annual bill impacts of an increase in the SGS Basic Charge to recover 45 per cent of customer-related costs

Percentile by Consumption	Annual kWh	F2017 Annual Bill Status Quo ($)	F2017 Annual Bill BC Hydro Proposal ($)	Annual Bill Difference between F2017 BC Hydro Proposal and F2017 Status Quo ($)	Annual Bill Difference between F2017 BC Hydro Proposal and F2017 Status Quo (%)	Bill Impact (%) of F2017 BC Hydro Proposal (vs. F2016 Rates)
Min	1	86	117	31	36	42
10	2,001	309	337	28	9	13
20	4,773	618	642	24	4	8
30	7,797	956	975	19	2	6
40	11,184	1,334	1,348	14	1	5
50	15,288	1,792	1,800	8	0	4
60	20,648	2,390	2,390	0	0	4
70	28,435	3,259	3,247	-12	0	-4
80	40,838	4,643	4,613	-30	-1	-3
90	65,174	7,359	7,292	-67	-1	-3
Max	615,810	68,810	67,918	-892	-1	-3

1.53.1 Please expand on how the proposed changes implement Bonbright's fairness principles with regard to cost causation for the low usage customers, whose bills would be impacted and how it implements fairness for the higher usage customers with regard to their cost causation.

RESPONSE:

BC Hydro's proposal to increase the level of the SGS basic charge to recover a greater proportion of customer-related costs improves intra-class fairness among SGS customers by allowing cost recovery to more closely follow cost causation. As shown in Table 6-3 of Exhibit B-2, higher consumption customers will see the largest benefit from the change because the proposal lowers the amount of the customer-related costs being recovered through the flat energy charge. Very low usage customers are more fairly charged the cost of remaining attached to the system, but are the greatest impacted because their usage is low and thus do not benefit from the lower energy charge to the same degree as high usage customers.

Please refer to BC Hydro's response to BCUC IR 1.55.1.

54.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-14 & 6-15

> The MGS Proposal would result in the following illustrative charges in F2018: a flat energy rate for all kWh of approximately 8.83 cents/kWh; a flat demand charge of approximately $4.92 per kW (reflecting BC Hydro's preferred 35 per cent level of cost recovery); and a basic charge of about 24.29 cents per day. BC Hydro proposes to continue with the current monthly minimum charge definition. These

1.54.1 Please confirm that as BC Hydro has discussed in its consultation with the CEC this proposal for a flat rate is intended for Module 1 and that BC Hydro will be open in Module 2 to options which may address providing a conservation price signal complementary with the flat rate as the base rate.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.52.1.

54.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-14 & 6-15

> The MGS Proposal would result in the following illustrative charges in F2018: a flat energy rate for all kWh of approximately 8.83 cents/kWh; a flat demand charge of approximately $4.92 per kW (reflecting BC Hydro's preferred 35 per cent level of cost recovery); and a basic charge of about 24.29 cents per day. BC Hydro proposes to continue with the current monthly minimum charge definition. These

1.54.2 Please confirm that the MGS flat rate level is below the BC Hydro LRMC on a going forward basis.

RESPONSE:

The simulations show that the proposed MGS flat energy rate is lower than the lower end of the Energy LRMC range (as shown on Exhibit B-1, Table 2-6), but remains generally reflective of the energy LRMC, as follows:

	Lower End of Energy LRMC Range (cents/kWh)	MGS Proposed Design Flat Energy Rate (cents/kWh)	Difference (cents/kWh)
F2017	**9.46**	**8.54**	**-0.92**
F2018	**9.65**	**8.83**	**-0.82**
F2019	**9.84**	**9.10**	**-0.74**

55.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-15 & 6-16

- A basic charge and a monthly minimum charge. The current MGS basic charge is 22.57 cents/day. The MGS monthly minimum charge is 50 per cent of the highest maximum demand charge billed in any billing period in the on-peak billing period.

1.55.1 Please discuss the rationale for having each of a basic charge, demand charge and monthly minimum charge in the rate structure.

RESPONSE:

A basic charge and a demand charge are intended to recover different types of costs:

- **The basic charge is a fixed charge per day to recover customer-related costs associated with remaining attached to BC Hydro's system;**
- **The demand charge is charge per kW to recover BC Hydro's demand-related costs typically associated with BC Hydro's costs to ensure it can serve peak system demand in winter along with localized demands in the system;**
    - **Associated with BC Hydro's demand charge and acknowledgement that winter peak loads drive a substantial portion of BC Hydro's infrastructure costs, a minimum charge (the demand ratchet referred to in the preamble above) ensures that customers with high winter consumption and low summer consumption pay a share of BC Hydro's costs to maintain its infrastructure related to serving peak demand in winter.**

BC Hydro notes that a number of surveyed Canadian utilities have demand charges and basic charges for large general service customers, including SaskPower, Manitoba Hydro, Newfoundland Power and New Brunswick Power. Refer to the Appendix to RDA Workshop 11a/11b at Appendix C-4B of Exhibit B-1, pages 130 to 132 of 382.

56.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-19

Table 6-6 Existing MGS Demand Charges (F2016)

First 35 kW of Billing Demand per Billing Period (Tier 1)	$0.00 per kW
Next 115 kW of Billing Demand per Billing Period (Tier 2)	$5.50 per kW
All additional kW of Billing Demand per Billing Period (Tier 3)	$10.55 per kW

Most jurisdictions have flat or declining demand charges. The key issue associated with the existing MGS three-step inclining block demand charge is that it does not align with BC Hydro's cost to serve MGS customer peak demand, which is generally flat on a $/kW basis.

1.56.1 Please confirm that MGS customers, depending upon their kW demand will see demand charges increase/(decrease) linearly, in absolute dollar charges, as their kW demand may increase/(decrease).

RESPONSE:

Confirmed, under BC Hydro's MGS flat demand charge proposal, subject to meeting threshold amounts associated with a minimum charge (demand ratchet).

56.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-19

Table 6-6 Existing MGS Demand Charges (F2016)

First 35 kW of Billing Demand per Billing Period (Tier 1)	$0.00 per kW
Next 115 kW of Billing Demand per Billing Period (Tier 2)	$5.50 per kW
All additional kW of Billing Demand per Billing Period (Tier 3)	$10.55 per kW

Most jurisdictions have flat or declining demand charges. The key issue associated with the existing MGS three-step inclining block demand charge is that it does not align with BC Hydro's cost to serve MGS customer peak demand, which is generally flat on a $/kW basis.

1.56.2 Please confirm that a single price signal for demand will provide simplicity, for understanding, relative to a 2 or 3 tier demand price.

RESPONSE:

Confirmed.

56.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-19

Table 6-6 Existing MGS Demand Charges (F2016)

First 35 kW of Billing Demand per Billing Period (Tier 1)	$0.00 per kW
Next 115 kW of Billing Demand per Billing Period (Tier 2)	$5.50 per kW
All additional kW of Billing Demand per Billing Period (Tier 3)	$10.55 per kW

Most jurisdictions have flat or declining demand charges. The key issue associated with the existing MGS three-step inclining block demand charge is that it does not align with BC Hydro's cost to serve MGS customer peak demand, which is generally flat on a $/kW basis.

1.56.3 Please confirm that in the long term the incremental cost of new capacity to service demand is expected to increase substantially from the current expected incremental cost and that this is because the opportunities to add inexpensive capacity on the BC Hydro system are close to being all used and or committed.

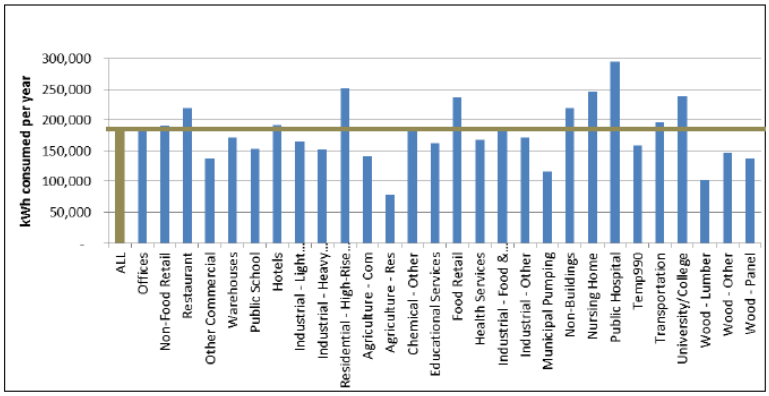
RESPONSE:

Confirmed with respect to generation capacity resources. Once Rev 6 (the last low cost generating capacity unit addition to BC Hydro's existing system) is installed, the next capacity generating options would be SCGTs or pumped storage facilities. The SCGT option is a step up in cost and its usage is limited as described in BC Hydro's response to BCOAPO IR 1.24.1; the pumped storage option is another step up in cost.

57.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-21

Figure 6-5 Median MGS Consumption by Site Type



1.57.1 Please confirm that for each of the median values shown above there would be a significant distribution of the MGS customers on either side of the median value and that this in addition to the data shown in Figure 6-5 is part of the information that leads BC Hydro to conclude that the heterogeneity of the rate class is too diverse to provide a single rate structure solution for providing appropriate price signals as efficiency incentives.

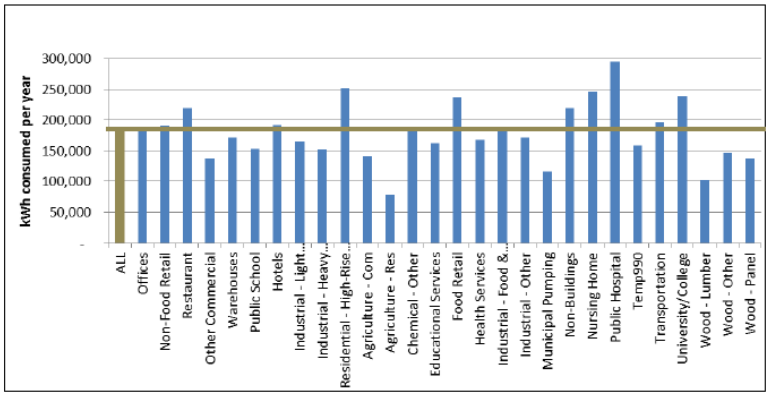
RESPONSE:

The range of the distribution of the entire class, inclusive of all site types has been discussed in Workshop 8a, which is shown on Exhibit B-1, Appendix C-4A, page 25 of 813. The intent of Exhibit B-1, Figure 6-5 is to show that the diverse range of consumption of the class may in part be due to the different site types. BC Hydro is of the view that an inclining block rate structure with a fixed threshold like the RIB rate is inappropriate for this class due to the heterogeneity and large range of consumptions.

57.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-21

Figure 6-5 Median MGS Consumption by Site Type



1.57.2 To the extent that BC Hydro has the statistical measure of the dispersion of the distribution around the median values could BC Hydro please provide that as well?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.57.1.

58.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-22

> The evaluation of these multiple lines of evidence indicated that the customer response to the MGS two-part energy rate was considerably less than forecast. Awareness and demonstrated understanding of the MGS rates was low. Evaluated net energy savings for MGS rate were not statistically different than zero in 2011, 2012 and F2014, relative to calendar year 2010, as compared to a forecast conservation savings of about 140 GWh/year.[237]

1.58.1 Please also confirm that with a 3 year rolling average price signal the MGS class of customers would not necessarily have a sustained payback on any initiatives they might take to create an economic justification for the investment.

RESPONSE:

BC Hydro notes the reference in the question to "a 3 year rolling average price signal" and clarifies that under the MGS and LGS two-part rates, a baseline load for each month is determined on a three-year rolling average of historical consumption in that month. Therefore, as baselines catch up with a new consumption level, Part 2 credits resulting from conservation initiatives diminish over the three-year period, and are not sustained.

58.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-22

> The evaluation of these multiple lines of evidence indicated that the customer response to the MGS two-part energy rate was considerably less than forecast. Awareness and demonstrated understanding of the MGS rates was low. Evaluated net energy savings for MGS rate were not statistically different than zero in 2011, 2012 and F2014, relative to calendar year 2010, as compared to a forecast conservation savings of about 140 GWh/year.[237]

1.58.2 Please confirm that this situation, of an inadequate economic justification, can also be a factor with respect to the fact that MGS customers did not appear to have a significant uptake of the price signal to result in energy savings.

RESPONSE:

The focus groups associated with F2014 LGS and MGS Evaluation Report identified the three-year rolling average as a contributing factor to perceived complexity of the existing MGS rate. Refer to Appendix C-4A of Exhibit B-1, page 545 of 813.

59.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-23

> In addition, BC Hydro carries forward in this Application an increase to the flat demand charge under alternative (1) above to recover 35 per cent of demand-related costs allocated to the MGS class in the 2016 COS study, an increase from the existing 15 per cent recovery under the current demand charge. The MGS rate alternatives brought forward into the 2015 RDA from the stakeholder engagement processes are summarized in Table 6-9.

1.59.1 In assessing the demand charge to be allocated to the MGS class and how much to recover in the rate structure please provide the percentage portion of demand charge that is associated with system generation assets and the portion associated with transmission and distribution assets.

RESPONSE:

Using Schedule 4.1 of the F2016 COS model, filed in Appendix E of Exhibit B-1, BC Hydro estimates that 24 per cent of MGS demand charge revenue is associated with generation demand-related costs while 76 per cent of revenue is associated with transmission and distribution demand-related costs.

59.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-23

> In addition, BC Hydro carries forward in this Application an increase to the flat demand charge under alternative (1) above to recover 35 per cent of demand-related costs allocated to the MGS class in the 2016 COS study, an increase from the existing 15 per cent recovery under the current demand charge. The MGS rate alternatives brought forward into the 2015 RDA from the stakeholder engagement processes are summarized in Table 6-9.

1.59.2 Please provide the absolute amount of the demand related costs allocated to the MGS class in the F2016 COS study.

RESPONSE:

The amount of demand-related costs allocated to the MGS rate class in F2016 is $162,500, as provided in Schedule 4.1 of the F2016 COS model (Appendix E of Exhibit B-1).

59.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-23

> In addition, BC Hydro carries forward in this Application an increase to the flat demand charge under alternative (1) above to recover 35 per cent of demand-related costs allocated to the MGS class in the 2016 COS study, an increase from the existing 15 per cent recovery under the current demand charge. The MGS rate alternatives brought forward into the 2015 RDA from the stakeholder engagement processes are summarized in Table 6-9.

1.59.3 Please confirm that system generation demand is planned in the BC Hydro system based on aggregate demand and would likely not be significantly influenced by individual customer demand profiles.

RESPONSE:

BC Hydro plans for system generation based on aggregate demand. Given the size of the system, individual customer demand would likely have less of an impact on system generation than on localized T&D systems. However, large customer demand can still significantly influence the system generation demand.

59.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-23

> In addition, BC Hydro carries forward in this Application an increase to the flat demand charge under alternative (1) above to recover 35 per cent of demand-related costs allocated to the MGS class in the 2016 COS study, an increase from the existing 15 per cent recovery under the current demand charge. The MGS rate alternatives brought forward into the 2015 RDA from the stakeholder engagement processes are summarized in Table 6-9.

1.59.4 Please confirm that the demand for the T&D system can be more specifically localized to specific customer demand profiles and is managed in a planning sense through a completely different process than the system generation demand.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.59.3 for the first part of the question.

Not confirmed with respect to the second question. For example, planning for both system generation and bulk transmission system is done in the IRP at a high level.

60.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-30

comparison to the total number of customers in each class. The amount of MGS and LGS demand ratchet revenue is a very small percentage of total MGS and LGS class revenue.

Table 6-11 Summary of F2015 demand ratchet charges, MGS and LGS

F2015 Demand Ratchet Charge	MGS	LGS
Total Customers Incurring Demand Ratchet	211	213
Percentage of Total Customers of Class	~ 1	~ 3
Total Demand Ratchet Revenue	$122,744	$1,794,043
Percentage of Total Revenue	~ 0.04	~ 0.2

1.60.1 Given how few customers are affected by the demand ratchet and how little revenue is impacted by the demand ratchet does BC Hydro's argument, that with so little effect BC Hydro would prefer to retain the ratchet, apply in reverse resulting in an argument that there is little reason to keep the ratchet?

RESPONSE:

In BC Hydro's view it is important to have a demand ratchet for the MGS and LGS classes:

- **For the reasons described in BC Hydro's response to CEC IR 1.55.1, a demand ratchet is an important component of the overall rate structure applicable to MGS and LGS customers; and**
- **A form of minimum charge through a demand ratchet is common utility practice in the rates for larger general service customers, as highlighted by BC Hydro's survey of default general service charges in Canada, at Attachment 5 to the Workshop 8a/8b Consideration Memo at Appendix C-4A of Exhibit B-1 (pages 394 to 396).**

61.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-32

Table 6-12 MGS Rate Estimates for Rate Structure Transition in F2017

MGS	F2016	F2017 Status Quo	F2017 BC Hydro Proposal (35% Demand Recovery)	F2017 Sensitivity (15% Demand Recovery)
Basic cents/day	22.57	23.47	23.47	23.47
Demand $/kW				
T1		–	4.76 Flat	2.14 Flat
T2	5.50	5.72		
T3	10.55	10.97		
Energy cents/kwh				
T1	9.89	10.33	8.54 Flat	9.35 Flat
T2	6.90	7.21		
Part 2	9.90	10.10		
Minimum	3.30	3.43		

1.61.1 Please confirm that the energy charged at Part 2 or Tier 1 will have a lower energy rate under BC Hydro's proposal the energy charged at Tier 2 will have a higher rate.

RESPONSE:

Confirmed, but for clarity BC Hydro restates the question in response as follows:

- **The proposed F2017 MGS flat rate (8.54 cents/kWh) is less than the Part 2 rate under the status quo (10.10 cents/kWh);**
- **The proposed F2017 MGS flat rate (8.54 cents/kWh) is less than the Part 1 Tier 1 rate under the status quo (10.33 cents/kWh); and**
- **The proposed F2017 MGS flat rate (8.54 cents/kWh) is greater than the Part 1 Tier 2 rate under the status quo (7.21 cents/kWh).**

61.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-32

Table 6-12 MGS Rate Estimates for Rate Structure Transition in F2017

MGS	F2016	F2017 Status Quo	F2017 BC Hydro Proposal (35% Demand Recovery)	F2017 Sensitivity (15% Demand Recovery)
Basic cents/day	22.57	23.47	23.47	23.47
Demand $/kW				
T1		–	4.76 Flat	2.14 Flat
T2	5.50	5.72		
T3	10.55	10.97		
Energy cents/kwh				
T1	9.89	10.33	8.54 Flat	9.35 Flat
T2	6.90	7.21		
Part 2	9.90	10.10		
Minimum	3.30	3.43		

1.61.2 Please provide the quantities of energy charged at each of T1, T2, and Part 2.

RESPONSE:

BC Hydro provides the following F2017 forecast estimates for consumption associated with the F2017 MGS status quo rates reported in Table 6-12 of Exhibit B-1. These figures are referenced from Table H-1A-31 on page 37 of Appendix H-1A of Exhibit B-1:

Forecast Part 1 Tier 1 Class Load: 2,449,649,233 kWh

Forecast Part 1 Tier 2 Class Load: 1,100,405,893 kWh

Forecast Part 2 LRMC Class Load: (23,066,251) kWh

Forecast Part 2 Tier 1 Class Load: (14,944,476) kWh

Forecast Part 2 Tier 2 Class Load 5,259,330 kWh.

61.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-32

Table 6-12 MGS Rate Estimates for Rate Structure Transition in F2017

MGS	F2016	F2017 Status Quo	F2017 BC Hydro Proposal (35% Demand Recovery)	F2017 Sensitivity (15% Demand Recovery)
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Demand $/kW				
T1		–	4.76 Flat	2.14 Flat
T2	5.50	5.72		
T3	10.55	10.97		
Energy cents/kwh				
T1	9.89	10.33	8.54 Flat	9.35 Flat
T2	6.90	7.21		
Part 2	9.90	10.10		
Minimum	3.30	3.43		

1.61.3 Please confirm that with customers not responding to price signals, fairness issues become a priority in the rate design considerations and that this is primarily what BC Hydro's proposal is designed to respond to.

RESPONSE:

Fairness is a priority but it is not the only objective underpinning BC Hydro's MGS proposal. As suggested by the question, with customers not responding to price signals, customer acceptance and understanding (including the overall practicality of the rate) is also a priority in the rate design considerations underlying BC Hydro's MGS proposal.

62.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-36 & 6-37

Figure 6-6 F2017 Bill Impacts less RRA – BC Hydro MGS Proposal (Demand 35 Per Cent Recovery)

Annual Consumption kWh — Highest kw

Load Factor *	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	44.0%	47.2%	6.9%	-2.6%	-6.8%	-14.0%	-20.1%	-22.3%	-23.9%	-25.1%	-26.0%	-26.8%	-27.4%	-27.9%	-28.3%	-28.7%	-29.0%
20%	14.1%	14.9%	15.1%	2.4%	-3.4%	-6.6%	-8.3%	-8.4%	-5.0%	-4.6%	-6.4%	-7.9%	-9.1%	-10.1%	-10.9%	-11.6%	-12.2%
30%	4.0%	4.2%	4.3%	4.3%	-1.7%	-5.3%	-7.3%	-5.4%	-3.5%	-2.2%	-1.1%	-0.2%	0.6%	1.2%	0.3%	-0.6%	-1.5%
40%	-1.1%	-1.1%	-1.2%	-1.2%	-1.2%	-4.6%	-6.7%	-4.4%	-2.5%	-1.2%	0.0%	0.9%	1.7%	2.5%	3.1%	3.6%	4.1%
50%	-4.1%	-4.3%	-4.4%	-4.4%	-3.4%	-4.4%	-6.3%	-3.9%	-2.1%	-0.6%	0.6%	1.7%	2.5%	3.3%	3.9%	4.5%	5.0%
60%	-6.1%	-6.5%	-6.6%	-6.6%	-6.0%	-5.0%	-6.2%	-3.5%	-1.6%	-0.1%	1.1%	2.2%	3.1%	3.9%	4.5%	5.1%	5.6%
70%	-7.6%	-8.0%	-8.1%	-8.2%	-8.2%	-8.2%	-7.9%	-3.5%	-1.3%	0.2%	1.5%	2.6%	3.5%	4.3%	5.0%	5.6%	6.1%
80%	-8.7%	-9.2%	-9.3%	-9.3%	-9.3%	-9.4%	-9.0%	-4.8%	-1.3%	0.5%	1.8%	2.9%	3.8%	4.6%	5.3%	5.9%	6.5%
90%	-9.5%	-10.0%	-10.2%	-10.2%	-10.3%	-10.3%	-9.9%	-5.7%	-2.3%	0.5%	2.0%	3.1%	4.1%	4.9%	5.6%	6.2%	6.8%

Lowest kw

Red underline indicates bill impact higher than RRA
Blue oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load

Figure 6-7 F2017 Bill Impacts less RRA – MGS Demand Sensitivity (15 Per Cent Recovery)

Annual Consumption kWh — Highest kw

Load Factor *	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	14.2%	15.0%	-13.4%	-21.2%	-24.7%	-30.5%	-35.8%	-37.4%	-38.7%	-39.6%	-40.4%	-41.0%	-41.5%	-41.9%	-42.2%	-42.5%	-42.8%
20%	4.9%	5.2%	5.3%	-6.4%	-11.7%	-14.7%	-16.2%	-14.5%	-13.2%	-12.9%	-14.6%	-15.9%	-17.0%	-17.9%	-18.6%	-19.3%	-19.9%
30%	0.4%	0.4%	0.4%	0.4%	-5.4%	-8.9%	-10.7%	-8.2%	-7.1%	-5.8%	-4.8%	-3.9%	-3.2%	-2.6%	-3.4%	-4.3%	-5.2%
40%	-1.9%	-2.0%	-2.0%	-2.0%	-2.0%	-5.4%	-7.5%	-5.2%	-3.5%	-2.1%	-0.9%	0.0%	0.8%	1.5%	2.2%	2.7%	3.2%
50%	-3.3%	-3.4%	-3.5%	-3.5%	-3.5%	-3.5%	-5.3%	-3.0%	-1.1%	0.4%	1.6%	2.7%	3.5%	4.3%	4.9%	5.5%	6.0%
60%	-4.2%	-4.4%	-4.5%	-4.5%	-4.5%	-4.5%	-4.1%	-1.3%	0.6%	2.2%	3.4%	4.5%	5.4%	6.2%	6.9%	7.5%	8.0%
70%	-4.9%	-5.1%	-5.2%	-5.2%	-5.2%	-5.2%	-4.3%	-0.9%	1.3%	3.5%	4.8%	5.9%	6.9%	7.7%	8.4%	9.0%	9.6%
80%	-5.3%	-5.6%	-5.7%	-5.7%	-5.7%	-5.7%	-5.3%	-0.9%	2.0%	4.5%	5.9%	7.0%	8.0%	8.9%	9.6%	10.2%	10.7%
90%	-5.7%	-6.0%	-6.1%	-6.1%	-6.1%	-6.1%	-5.7%	-1.4%	2.2%	5.1%	6.7%	7.9%	8.9%	9.7%	10.5%	11.1%	11.7%

Lowest kw

Red underline indicates bill impact higher than RRA
Blue oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load

1.62.1 Please confirm that while the increased recovery of demand charge reduces the unfairness in rewarding efficient load factor use of the BC Hydro system the differences between low load factor customers and high load factor customers does not completely redress the issue but does significantly mitigate the issue.

RESPONSE:

Confirmed. Please refer to BC Hydro's response to BCUC IRs 1.82.3 and 1.82.4.

63.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-38

> The LGS Proposal would result in the following illustrative charges in F2018: a flat energy rate for all kWh of approximately 5.56 cents/kWh; a flat demand charge of approximately $11.21 per kW (reflecting BC Hydro's preferred 65 per cent level of cost recovery); and a basic charge of approximately 24.29 cents per day. BC Hydro proposes to continue with the current monthly minimum charge definition. These illustrative charges are calculated assuming the F2018 rate cap increase of 3.5 per cent. Final F2018 LGS pricing will be determined by the F2017 RRA decision.

1.63.1 In assessing the demand charge to be allocated to the LGS class and how much to recover in the rate structure please provide the percentage portion of demand charge that is associated with system generation assets and the portion associated with transmission and distribution assets.

RESPONSE:

Using Schedule 4.1 of the F2016 COS model, filed in Appendix E of Exhibit B-1, BC Hydro estimates that 28 per cent of LGS demand charge revenue is associated with generation demand-related costs while 72 per cent of revenue is associated with transmission and distribution demand-related costs.

63.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-38

> The LGS Proposal would result in the following illustrative charges in F2018: a flat energy rate for all kWh of approximately 5.56 cents/kWh; a flat demand charge of approximately $11.21 per kW (reflecting BC Hydro's preferred 65 per cent level of cost recovery); and a basic charge of approximately 24.29 cents per day. BC Hydro proposes to continue with the current monthly minimum charge definition. These illustrative charges are calculated assuming the F2018 rate cap increase of 3.5 per cent. Final F2018 LGS pricing will be determined by the F2017 RRA decision.

1.63.2 Please provide the absolute amount of the demand related costs allocated to the LGS class in the F2016 COS study.

RESPONSE:

The amount of demand-related costs allocated to the LGS rate class in F2016 is $403 million, as provided in Schedule 4.1 of the F2016 COS model (Appendix E, Exhibit B-1).

63.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-38

> The LGS Proposal would result in the following illustrative charges in F2018: a flat energy rate for all kWh of approximately 5.56 cents/kWh; a flat demand charge of approximately $11.21 per kW (reflecting BC Hydro's preferred 65 per cent level of cost recovery); and a basic charge of approximately 24.29 cents per day. BC Hydro proposes to continue with the current monthly minimum charge definition. These illustrative charges are calculated assuming the F2018 rate cap increase of 3.5 per cent. Final F2018 LGS pricing will be determined by the F2017 RRA decision.

1.63.3 Please confirm that system generation demand is planned in the BC Hydro system based on aggregate demand and would likely not be significantly influenced by individual LGS customer demand profiles.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.59.3.

63.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-38

> The LGS Proposal would result in the following illustrative charges in F2018: a flat energy rate for all kWh of approximately 5.56 cents/kWh; a flat demand charge of approximately $11.21 per kW (reflecting BC Hydro's preferred 65 per cent level of cost recovery); and a basic charge of approximately 24.29 cents per day. BC Hydro proposes to continue with the current monthly minimum charge definition. These illustrative charges are calculated assuming the F2018 rate cap increase of 3.5 per cent. Final F2018 LGS pricing will be determined by the F2017 RRA decision.

1.63.4 Please confirm that the demand for the T&D system can be more specifically localized to specific customer demand profiles and is managed in a planning sense through a completely different process than the system generation demand.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.59.4.

64.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-40

12 **Table 6-14 Existing LGS Energy Rates (F2016)**

Part 1 Energy Rate – Tier 1 (cents/kWh)	10.66
Part 1 Energy Rate – Tier 2 (cents/kWh)	5.13
Part 2 Energy Rate (cents/kWh)	9.90

1.64.1 Please confirm that the price signal difference, while significant, is nonetheless not relevant for conservation because BC Hydro cannot detect and cannot plan to rely on conservation from the rate structure.

RESPONSE:

BC Hydro regards there to be a significant price signal difference between the Part 2 rate and the Part 1 Tier 2 rate and between the Part 1 Tier 1 rate and the Part 1 Tier 2 rate. BC Hydro does not consider there to be a significant price signal difference between the Part 2 rate and the Part 1 Tier 1 rate; both prices are relatively close in value.

BC Hydro confirms that the LGS two-part energy rate has been evaluated to have delivered lower than expected conservation savings (77 GWh/year by the end of F2014) and that BC Hydro has forecasted zero conservation savings from the LGS two-part energy rate if it was to continue.

64.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-40

12 **Table 6-14 Existing LGS Energy Rates (F2016)**

Part 1 Energy Rate – Tier 1 (cents/kWh)	10.66
Part 1 Energy Rate – Tier 2 (cents/kWh)	5.13
Part 2 Energy Rate (cents/kWh)	9.90

1.64.2 Please confirm that, because of the 3 year rolling average effect, one of the factors for customers, in considering the price signal, is that the economic benefit from investing in making savings has a very limited payback, in terms of the marginal price signal.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.58.1.

65.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-43

> BC Hydro has a three-step inclining block demand charge for the LGS rate class which is the same structure and the same charges as applicable to the MGS rate class set out in Table 6-6. The key issue with the LGS demand structure is the same key issue identified with respect to the MGS demand structure in section 6.3.2.2; the LGS three-step inclining block demand charge does not align with BC Hydro's cost to serve LGS customer peak demand.

1.65.1 Please confirm that each kW of demand aggregates to create the same cost causation for the need to supply capacity for the BC Hydro system peak as every other kW of demand.

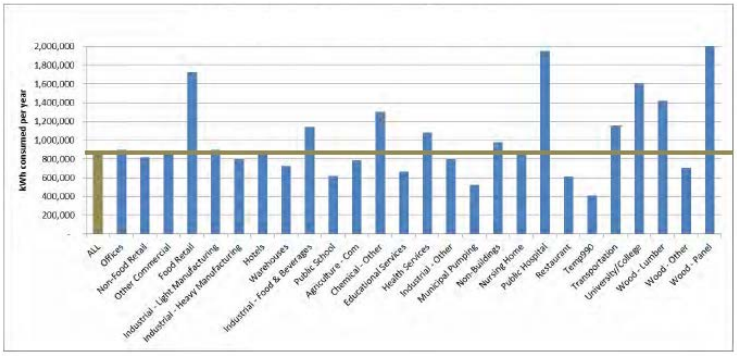
RESPONSE:

Not confirmed. Individual customer peak loads are not necessarily coincident to the system peak.

66.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, 6-45

1 **Figure 6-9 Median LGS Consumption by Site Type**



1.66.1 Please confirm that for each of the median values shown above there would be a significant distribution of the LGS customers on either side of the median value and that this in addition to the data shown in Figure 6-9 is part of the information that leads BC Hydro to conclude that the heterogeneity of the rate class is too diverse to provide a single rate structure solution for providing appropriate price signals as efficiency incentives.

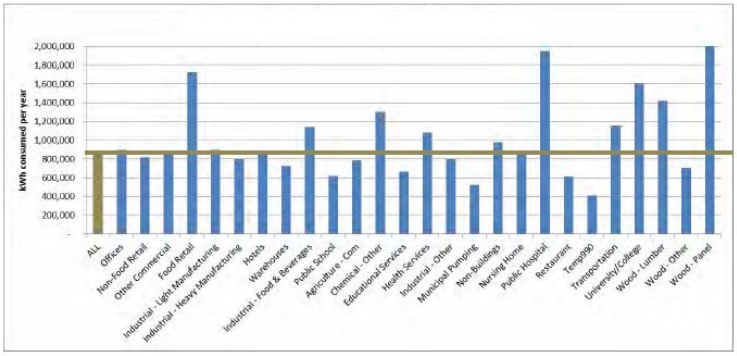
RESPONSE:

The range of the distribution of the entire class, inclusive of all site types has been discussed in Workshop 8a, which is shown on Exhibit B-1, Appendix C-4A, page 21 of 813. The intent of Exhibit B-1, Figure 6-9 is to show that the diverse range of consumption of the class may in part be due to the different site types. BC Hydro is of the view that an inclining block rate structure with a fixed threshold like the RIB rate is inappropriate for this class due to the heterogeneity and large range of consumptions.

66.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, 6-45

Figure 6-9 Median LGS Consumption by Site Type



1.66.2 To the extent that BC Hydro has the statistical measure of the dispersion of the distribution around the median values could BC Hydro please provide that as well?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.66.1.

67.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-53

- AMPC and CEC, who represent LGS customers, favoured the LS-5 flat energy rate with a BC Hydro commitment to explore alternative concepts. AMPC considered that the current baseline approach is not sufficiently flexible for larger LGS customers who tend to experience significant changes in operations and conservation investments. AMPC suggests that a LGS TSR-Like Rate similar to RS 1823 where baselines can be individually administered would be more appropriate and effective for the largest LGS customers (Viterra also strongly favoured a LGS TSR-Like Rate targeted to larger LGS customers);[244]

1.67.1 Please confirm that when LGS customers were presented with alternatives they were only presented the screened alternative options and were not presented with the idea that other alternatives may be explored in Module 2, which may address the incentives they are looking for to enable them to invest cost-effectively in conservation and efficiency.

RESPONSE:

Not confirmed. In the Workshop 8(b) slide deck found in Appendix C-4A of Exhibit B-1, BC Hydro presented both the screened in alternatives (Topic #2) as well as the screened-out alternatives (Topic #5).

As part of the Workshop 8(a)/8(b) stakeholder feedback CEC raised the idea of an Efficiency Rate Credit design. As described in section 6.3, pages 214 to 215 of 813 of the Workshop 8(a)/8(b) consideration memo, BC Hydro indicated that there were a number of steps that needed to be overcome prior to the consideration of such a rate and that BC Hydro would continue to pursue the topic with the Electricity Conservation and Efficiency Advisory Committee and provide an update at Workshop 11(a)/11(b). In Workshop 11(b) (slide 56) found at page 116 of 382 in Appendix C-4B of Exhibit B-1, BC Hydro indicated that it would assess optional rates such as the Efficiency Rate Credit concept as part of Module 2 after the default General Service rates are determined.

67.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-53

- AMPC and CEC, who represent LGS customers, favoured the LS-5 flat energy rate with a BC Hydro commitment to explore alternative concepts. AMPC considered that the current baseline approach is not sufficiently flexible for larger LGS customers who tend to experience significant changes in operations and conservation investments. AMPC suggests that a LGS TSR-Like Rate similar to RS 1823 where baselines can be individually administered would be more appropriate and effective for the largest LGS customers (Viterra also strongly favoured a LGS TSR-Like Rate targeted to larger LGS customers);[244]

1.67.2 Please confirm that for those customers who have found that there is some incentive in the LGS rate structure it may be possible for them through Module 2 or other approaches to ensure that they do not lose the benefits of being able to invest in conservation and efficiency.

RESPONSE:

The benefits of investing in conservation and efficiency are not strictly tied to the presence of the LGS rate structure. Although the cost savings may be less, energy conservation and efficiency measures help reduce the overall electricity cost of customers even with a flat rate.

As described in BC Hydro's response to CEC IR 1.52.1, BC Hydro will explore optional rates for General Service customers as part of RDA Module 2.

67.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-53

- AMPC and CEC, who represent LGS customers, favoured the LS-5 flat energy rate with a BC Hydro commitment to explore alternative concepts. AMPC considered that the current baseline approach is not sufficiently flexible for larger LGS customers who tend to experience significant changes in operations and conservation investments. AMPC suggests that a LGS TSR-Like Rate similar to RS 1823 where baselines can be individually administered would be more appropriate and effective for the largest LGS customers (Viterra also strongly favoured a LGS TSR-Like Rate targeted to larger LGS customers);[244]

1.67.3 Please confirm that particularly for customers who have growth related issues or variable production issues with the LGS rate structure SQ, the provisions intended to help mitigate these issues have either not worked well for the customers or have added to BC Hydro's administrative complexity costs.

RESPONSE:

Confirmed. Some of the LGS rate provisions, such as the formulaic growth rule, have sometimes resulted in higher bills to customers. For further discussion, please refer to the Workshop 8a/8b Consideration Memo at Appendix C-4A of Exhibit B-1 (pages 195 to 198 of 813).

68.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-56

> 1. The LGS Flat Energy rate and LGS Flat Demand Charge are its preferred LGS rate structures to carry forward to the 2015 RDA, which is supported by many LGS customers and organizations representing such customers, and most other stakeholders;

1.68.1 Please confirm that the 3 step demand charge was originated and was applicable to the General Service rate class when it was not segmented into three groups, SGS, MGS and LGS.

RESPONSE:

The existing three-step demand charge structure has been in place since 1980 and has applied to General Service customers with demand greater than 35 kW.

68.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-56

> 1. The LGS Flat Energy rate and LGS Flat Demand Charge are its preferred LGS rate structures to carry forward to the 2015 RDA, which is supported by many LGS customers and organizations representing such customers, and most other stakeholders;

1.68.2 Please confirm that the BC Hydro proposed approach to single rate flat demand charges for the three General Service rate class segments is similar to the 3 tier approach used for the combined General Service rate class, except for the stacking of the tiers instead of the independent levels for each rate class.

RESPONSE:

Not confirmed.

For the reasons summarized in section 6.2.3.1 of Exhibit B-1, BC Hydro rejects a demand charge for SGS rates, and so the applicability of this question to the SGS class is limited; that is, BC Hydro has not proposed "single rate flat demand charges for the three General Service rate class segments."

BC Hydro accepts that each step in the current MGS and LGS three-step demand charge corresponds to the level of demand that defines each rate class; that is, a SGS customer by definition does not pay for demand up to 35 kW, a MGS customer by definition would generally pay for demand up to 150 kW, and a LGS customer would generally pay for demand at levels greater than 150 kW.

However, BC Hydro does not accept that the current three tier demand charge structure is similar to the proposed flat demand charge for MGS and LGS customers because a single flat demand charge will improve fairness between customers. The proposed flat demand charges are better aligned with the cost to serve LGS and MGS customer peak demand. A flat demand charge also simplifies the MGS and LGS rate structures, which will improve customer understanding and acceptance relative to the existing inclining block demand charge structure.

68.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-56

> 1. The LGS Flat Energy rate and LGS Flat Demand Charge are its preferred LGS rate structures to carry forward to the 2015 RDA, which is supported by many LGS customers and organizations representing such customers, and most other stakeholders;

1.68.3 Please confirm that as the size of the electricity demand requirements increase for BC Hydro's customers the issues of the efficiency of use of investment in the infrastructure to serve the demand becomes more critical to both BC Hydro and the customers in terms of opportunity to cost-effectively reduce the costs of service, providing a logic for explicit alignment of demand recovery more closely with cost causation.

RESPONSE:

Confirmed, although in BC Hydro's view aligning the MGS and LGS demand charge recover of demand-related costs is not contingent on increasing electricity demand requirements.

69.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-58 & 6-59

Figure 6-10 F2017 Bill Impacts less RRA for LGS Flat Energy and Flat Demand, Demand Cost Recovery = ~50 Per Cent

Annual Consumption kWh — Highest kW

Load Factor	200,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	-10.9%	-12.8%	-13.5%	-13.8%	-14.0%	-14.1%	-14.2%	-14.2%	-14.3%	-14.3%	-14.4%	-14.4%	-14.4%	-14.4%	-14.5%	-14.5%	-14.5%
20%	-11.4%	-6.1%	-7.1%	[illegible]	[illegible]	-8.2%	-8.3%	-8.4%	-8.5%	-8.6%	-8.6%	-8.7%	-8.7%	-8.8%	-8.8%	-8.8%	-8.8%
30%	-18.0%	-1.5%	-2.9%	-3.6%	-4.0%	-4.3%	-4.5%	-4.6%	-4.7%	-4.8%	-4.9%	-4.9%	-5.0%	-5.0%	-5.1%	-5.1%	-5.1%
40%	-22.0%	-4.7%	0.1%	-0.7%	-1.2%	-1.5%	[illegible]	-1.9%	-2.0%	-2.1%	-2.2%	-2.3%	-2.3%	-2.4%	-2.4%	-2.5%	-2.5%
50%	-24.5%	-7.1%	0.6%	1.5%	0.9%	0.6%	[illegible]	0.1%	0.0%	-0.1%	-0.2%	-0.3%	-0.4%	-0.4%	-0.5%	-0.5%	-0.5%
60%	-26.3%	-8.8%	[illegible]	3.1%	2.6%	2.2%	1.9%	1.7%	1.6%	1.4%	1.3%	1.2%	1.2%	1.1%	1.1%	1.0%	1.0%
70%	-28.3%	-10.1%	-2.2%	2.2%	[illegible]	3.5%	3.2%	3.0%	2.8%	2.7%	2.6%	2.5%	2.4%	2.3%	2.3%	2.2%	2.2%
80%	-30.3%	-11.1%	-3.2%	1.3%	4.2%	4.9%	4.2%	4.0%	3.8%	3.7%	3.6%	3.5%	3.4%	3.3%	3.3%	3.2%	3.2%
90%	-31.9%	-11.9%	-3.9%	0.6%	3.5%	5.4%	5.1%	4.9%	4.6%	4.5%	4.4%	4.3%	4.2%	4.1%	4.1%	4.0%	4.0%

Lowest kW

Red font indicates bill impact higher than RRA
Oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load factor.

Figure 6-11 F2017 Bill Impacts less RRA for LGS Flat Energy and Flat Demand, Demand Cost Recovery = ~65 Per Cent

Annual Consumption kWh — Highest kW

Load Factor	200,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	0.8%	-1.7%	-2.4%	-2.7%	-2.9%	-3.1%	-3.2%	-3.2%	-3.3%	-3.3%	-3.4%	-3.4%	-3.4%	-3.4%	-3.4%	-3.5%	-3.5%	-3.5%
20%	-4.8%	0.9%	[illegible]	[illegible]	[illegible]	-1.3%	-1.5%	-1.6%	-1.7%	-1.8%	-1.8%	-1.9%	-1.9%	-1.9%	-1.9%	-2.0%	-2.0%	-2.0%
30%	-14.5%	2.7%	1.2%	0.8%	0.1%	-0.2%	-0.4%	-0.5%	-0.6%	-0.7%	-0.8%	-0.9%	-0.9%	-0.9%	-1.0%	-1.0%	-1.0%	-1.1%
40%	-20.2%	-2.6%	2.3%	1.4%	1.0%	0.6%	[illegible]	0.2%	0.1%	0.0%	-0.1%	-0.2%	-0.2%	-0.3%	-0.3%	-0.3%	-0.4%
50%	-24.0%	-6.5%	1.2%	2.1%	1.6%	1.2%	[illegible]	0.8%	0.7%	0.6%	0.5%	0.4%	0.3%	0.3%	0.2%	0.2%	0.1%
60%	-26.7%	-9.2%	[illegible]	2.7%	2.1%	1.7%	[illegible]	1.3%	1.1%	1.0%	0.9%	0.8%	0.7%	0.7%	0.6%	0.6%	0.5%
70%	-29.2%	-11.3%	-3.5%	[illegible]	[illegible]	[illegible]	[illegible]	1.6%	1.4%	1.3%	1.2%	1.1%	1.0%	1.0%	0.9%	0.9%	0.8%
80%	-31.8%	-12.9%	-5.1%	-0.7%	2.1%	2.4%	2.1%	1.9%	1.7%	1.6%	1.5%	1.4%	1.3%	1.2%	1.2%	1.1%	1.1%
90%	-33.7%	-14.2%	-6.4%	-2.0%	0.8%	2.7%	2.4%	2.1%	2.0%	1.8%	1.7%	1.6%	1.5%	1.5%	1.4%	1.3%	1.3%

Lowest kW

Red font indicates bill impact higher than RRA
Oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load factor.

1.69.1 Please confirm that data above shows significant mitigation of the alignment of load factor cost causation with the demand charge recovery of costs, leading to a fairer rate structure proposal based on Bonbright's principles.

RESPONSE:

Confirmed.

70.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-63

Table 6-20 LGS Rate estimates given rate structure transition in F2017

LGS	F2016	F2017 Status Quo	F2017 BC Hydro Proposal (65% Demand Recovery)	F2017 Sensitivity (50% Demand Recovery)
Basic cents/day	22.57	23.47	23.47	23.47
Demand $/kW				
T1			10.83 Flat	8.35 Flat
T2	5.50	5.72		
T3	10.55	10.97		
Energy cents/kwh				
T1	10.66	11.17	5.37 Flat	5.98 Flat
T2	5.13	5.37		
Part 2	9.90	10.10		
Minimum	3.30	3.43		

1.70.1 Please confirm that the Energy Flat rate is well below the LRMC for new energy supply presenting an opportunity to determine whether or not there are more effective means for incenting conservation and efficiency for this heterogeneous rate classes such as LGS.

RESPONSE:

BC Hydro confirms that the proposed LGS Flat rate is well below the energy LRMC range. As described in BC Hydro's response to CEC IR 1.52.1, BC Hydro will be examining optional rates for the General Service class as part of Module 2 of the RDA.

70.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-63

Table 6-20 LGS Rate estimates given rate structure transition in F2017

LGS	F2016	F2017 Status Quo	F2017 BC Hydro Proposal (65% Demand Recovery)	F2017 Sensitivity (50% Demand Recovery)
Basic cents/day	22.57	23.47	23.47	23.47
Demand $/kW				
T1			10.83 Flat	8.35 Flat
T2	5.50	5.72		
T3	10.55	10.97		
Energy cents/kwh				
T1	10.66	11.17	5.37 Flat	5.98 Flat
T2	5.13	5.37		
Part 2	9.90	10.10		
Minimum	3.30	3.43		

1.70.2 Please confirm that BC Hydro will be open in Module 2 to exploring alternatives to see if any may more effectively incent conservation and efficiency than rate structures are likely to accomplish.

RESPONSE:

BC Hydro is open to exploring optional rate structures that may incent conservation as part of RDA Module 2.

71.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-68

A three-year phase-in period for BC Hydro's preferred MGS rate (F2017-F2019) would have only minor mitigation of bill impacts as compared to no phase-in (i.e., one-time F2018 implementation) impacts:

- Under a three-year phase-in, customers who experience adverse bill impacts greater than 10 per cent are limited to about 800 accounts with less than about 40 MWh/year of annual consumption; and

1.71.1 Please provide the percentage of accounts for MGS which 800 accounts represents and the percentage of energy consumption for MGS that 40 MWh/year represents.

RESPONSE:

Eight hundred accounts are about 5 per cent of MGS accounts.

An account with 40 MWh/year represents about 0.001 per cent of MGS class consumption.

71.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-68

A three-year phase-in period for BC Hydro's preferred MGS rate (F2017-F2019) would have only minor mitigation of bill impacts as compared to no phase-in (i.e., one-time F2018 implementation) impacts:

- Under a three-year phase-in, customers who experience adverse bill impacts greater than 10 per cent are limited to about 800 accounts with less than about 40 MWh/year of annual consumption; and

1.71.2 Please confirm that the adverse bill impact in the case of MGS customers, which might cause one to look at options to phase-in the changes is in fact redressing a long standing under collection from these customers relative to cost causation principles.

RESPONSE:

The question implies that adverse bill impacts can be ignored if rate changes are consistent with past cost causation principles. The design of electricity rates is a complex process that involves the balancing of numerous quantitative and qualitative criteria. Realignment of rates with costs (fairness) is one criterion for rate redesign, but BC Hydro believes that adverse bill impacts, measured by year of year expected changes in bills, are also important and must be considered along with other Bonbright criteria.

72.0 E. Chapter 6 – General Service Rate Design

Reference: Exhibit B-1, Page 6-72

- There would be no need for TS 82. Refer to section 6.7.1;
- There would be no need for the existing LGS and MGS control groups used to help evaluate the conservation effects of the existing MGS and LGS rates. Refer to section 6.7.2;
- There would be no need for RS 26xx which exempts Corix from the LGS two-part rate. See section 6.7.3.

1.72.1 Please confirm that there are no negative consequences anticipated in regard to eliminating these three provisions, where the proposed rate design has eliminated the need for the provision.

RESPONSE:

Confirmed.

73.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, Page 7-9 & 7-13

> Tier 2 within the range of LRMC (with inflation). Option 1 is not forecast revenue neutral in F2017 since the bill neutrality definition of revenue neutrality is used to determine the Tier 1 rate once the Tier 2 rate is increased by an amount greater than the RRA rate increase so that it is at the lower end of the LRMC range. Since in F2018 and F2019 the RRA rate increases are applied to the Tier 1 and Tier 2 rates equally, Option 1 is forecast revenue neutral in F2018 and F2019 as well as customer bill neutral. Option 1 prioritizes the Bonbright

> The bill neutrality definition of revenue neutrality is unique to RS 1823. The RIB, LGS, MGS and SGS rates are all determined on a forecast revenue neutrality basis. This means that the calculated RIB, LGS, MGS and SGS rates collect the same revenue as the target revenue in each rate class by design and on a forecast basis.

> BC Hydro reviewed the revenue impacts associated with the three pricing principle options relative to forecast revenue neutrality in Attachment 4 to the Workshop 5 consideration memo:
>
> - Option 1 under-recovers revenue in F2017 by $2.2 million;[262]

1.73.1 Please discuss whether or not an application of a rate increase, which is not forecast revenue neutral, is effectively creating a rebalancing in contravention of the LGIC direction or does it just create an under collection of the revenue requirement for the F2017 year.

RESPONSE:

No.

CEC asked a similar question with respect to FortisBC and New Westminster at Workshop 12; please refer to the Workshop 12 summary notes at Exhibit B-1, Appendix C-1B, page 91 of 115, question no. 8.

The application of RRA increases to RS 1823 using either definition of revenue neutrality (i.e., bill neutral or forecast revenue neutral) will lead to differing projected revenues if in aggregate customers are not expected to consume exactly at their respective Customer Baseline Load (CBL) during the test year.

Subsection 9(3) of Direction No. 7 provides that for F2017-F2019, the Commission "must not set rates for [BC Hydro] *for the purpose of changing the revenue-cost ratio for a class of customers*." Since any projected revenue shortfall or surplus for the test year results from differing definitions of revenue neutrality rather than an effort to adjust R/C ratios between rate classes, the application of RRA increases using the bill neutrality definition of revenue neutrality does not create a rebalancing in contravention of the Rate Rebalancing Amendment.

73.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, Page 7-9 & 7-13

> Tier 2 within the range of LRMC (with inflation). Option 1 is not forecast revenue neutral in F2017 since the bill neutrality definition of revenue neutrality is used to determine the Tier 1 rate once the Tier 2 rate is increased by an amount greater than the RRA rate increase so that it is at the lower end of the LRMC range. Since in F2018 and F2019 the RRA rate increases are applied to the Tier 1 and Tier 2 rates equally, Option 1 is forecast revenue neutral in F2018 and F2019 as well as customer bill neutral. Option 1 prioritizes the Bonbright
>
> The bill neutrality definition of revenue neutrality is unique to RS 1823. The RIB, LGS, MGS and SGS rates are all determined on a forecast revenue neutrality basis. This means that the calculated RIB, LGS, MGS and SGS rates collect the same revenue as the target revenue in each rate class by design and on a forecast basis.
>
> BC Hydro reviewed the revenue impacts associated with the three pricing principle options relative to forecast revenue neutrality in Attachment 4 to the Workshop 5 consideration memo:
>
> - Option 1 under-recovers revenue in F2017 by $2.2 million;[262]

1.73.2 Please describe the impact on all customer group RC ratios as a consequence of implementing a non-forecast revenue neutral approach as opposed to implementing a forecast revenue neutral approach for the transmission rate.

RESPONSE:

Page 7-13 of Exhibit B-1 shows the revenue impacts associated with the three pricing principle options relative to forecast revenue neutrality. The under-recoveries from the Transmission Service rate class are $2.2 million (Options 1 and 2) and $8.8 million (Option 3) in F2017. To calculate the impact on other rate class R/C ratios, BC Hydro assumes the above under-recoveries existed in F2016 as the filed F2016 COS study is based on F2016 costs and revenues. BC Hydro also assumes any under-recoveries are allocated to other rate classes on a pro-rata basis using share of total revenue.

	Total class revenue in the F2016 COS ($millions)	**Increase in Revenue as a result of the under-recovery in transmission rate class revenue ($millions)**	
		Options 1 and 2	**Option 3**
Residential	**1,917.6**	**+1.18**	**+4.73**
SGS	**411.8**	**+0.25**	**+1.02**
MGS	**360.5**	**+0.22**	**+0.89**
LGS	**836.1**	**+0.52**	**+2.06**
Irrigation	**6.0**	**+0.00**	**+0.01**
BC Hydro owned Street Lighting	**20.6**	**+0.01**	**+0.05**
Customer owned Street Lighting	**17.8**	**+0.01**	**+0.04**
Total ($ million)		**+2.2**	**+8.8**

Options 1 and 2 result in a 0.06 percentile increase in class R/C ratios while Option 3 results in a 0.24 percentile increase. For example, the Residential rate class' R/C ratio rises from 93.89 per cent to 93.95 per cent under Options 1 and 2.

74.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, Page 7-20

> Aside from COPE 378 (at Workshop 10), no stakeholder providing feedback on this topic supported BC Hydro pursuing a reconfigured RS 1825. AMPC and its members favoured BC Hydro focusing on the freshet rate pilot (and load curtailment pilot). AMPC reasoned that overall complexity, low margins, price risk and the current three-year commitment requirement combine to make RS 1825 less attractive to Transmission Service customers than RS 1823. AMPC's feedback is consistent with the feedback received at the May to June 2014 regional sessions with Transmission Service customers outlined in section 2.2.3.4 of the Application, at which a majority of Transmission Service customers indicated that TOU rates would not work for their businesses since they operate a continuous manufacturing

1.74.1 In the event that new Transmission Service customers were to locate in the province and had a load profile and process capability, which enabled switching its process between requiring electricity and being 'self-sufficient' would BC Hydro reconsider its position on this rate.

RESPONSE:

BC Hydro is proposing to maintain the existing RS 1825, thus it would be available to new or existing Transmission Service customers who felt the rate would be beneficial to them. If such a customer felt that modifications to RS 1825 were needed, BC Hydro would consider the changes and engage with stakeholders on any proposed changes, and if warranted approach the Government concerning whether such changes should be referred to the Commission under section 5 of the *UCA* for recommendations.

74.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, Page 7-20

> Aside from COPE 378 (at Workshop 10), no stakeholder providing feedback on this topic supported BC Hydro pursuing a reconfigured RS 1825. AMPC and its members favoured BC Hydro focusing on the freshet rate pilot (and load curtailment pilot). AMPC reasoned that overall complexity, low margins, price risk and the current three-year commitment requirement combine to make RS 1825 less attractive to Transmission Service customers than RS 1823. AMPC's feedback is consistent with the feedback received at the May to June 2014 regional sessions with Transmission Service customers outlined in section 2.2.3.4 of the Application, at which a majority of Transmission Service customers indicated that TOU rates would not work for their businesses since they operate a continuous manufacturing

1.74.2 In the event that such a new Transmission Service customer came to BC would BC Hydro be able to react and put such a rate in place to facilitate a mutually favourable opportunity for the new business.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.74.1.

75.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, Page 7-22

- CEC suggested RS 1852 should be retained but refined to better match BC Hydro's system demand issues. BC Hydro agrees with the suggestion. RS 1852 was originally designed around Vancouver Island's unique 'two peak' system load (6 a.m. to 10 a.m. and 4 p.m. to 8 p.m.). However, as demonstrated in section 4.2 of the Consideration Memo, the South Peace region does not have a two peak system load. Areas that may be transmission constrained in the future include the Lower Mainland (depending on the number of LNG proposals that proceed) and the North Coast/Prince Rupert region. Accordingly, BC Hydro prefers to have discretion to determine the HLH period(s) that will apply based on customer location/region because transmission constraints change over time and by location.

1.75.1 Please discuss when refinement of 1852 might be undertaken and whether or not this is a likely candidate for Module 2.

RESPONSE:

BC Hydro is currently not planning any further refinement of RS 1852. BC Hydro's proposal for RS 1852 addresses the refinement advanced by CEC in the preamble to this IR.

76.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, Page 7-26

> BC Hydro seeks approval of the freshet rate no later than February 1, 2016 as a two-year pilot to run between the May to July 2016 and May to July 2017 freshet periods.

1.76.1 Is it possible that for a company to make good economic use of such a rate it may need to have the potential for a longer term pilot?

RESPONSE:

Yes, it is possible. BC Hydro notes that no stakeholders at Workshop 10 opposed BC Hydro's proposal for a two-year pilot.

76.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, Page 7-26

> BC Hydro seeks approval of the freshet rate no later than February 1, 2016 as a two-year pilot to run between the May to July 2016 and May to July 2017 freshet periods.

1.76.2 Would BC Hydro be open to retaining some flexibility with regard to the length of time and perhaps some other terms with respect to this pilot in order to ensure that it has the ability to work with customers to optimize the potential from such a rate.

RESPONSE:

It is not clear to BC Hydro whether CEC is asking about lengthening the two years of the pilot or the three month freshet period.

With respect to the former, BC Hydro is open to offering the pilot as a rate on a permeant basis subject to the evaluation results to be submitted to the Commission.

BC Hydro considered adopting a more flexible freshet period but noted in the Workshop 10 consideration memo, found in Appendix C-5B, pages 82 to 83 of 212, Exhibit B-1, that there was broad stakeholder support for using a May to July period. Key reasons for using a fixed three month period include:

- **The start of the freshet period varies from year to year and is highly sensitive to temperature conditions in the April and May period. The end date of the freshet period depends on changes in market prices as summer loads increase in the California market typically between mid-July and mid-August;**
- **Affords customers a degree of certainty and may facilitate greater customer participation relative to a variable period; and**
- **The setting of baselines is simpler relative to a variable period.**

77.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, Page 7-26 & 7-27

As discussed in sections 1.1.3 and 7.1 of the Application, BC Hydro is proposing to create a new optional rate (RS 1892) for non-firm service during these freshet periods. RS 1892 would be available to customers taking service under RS 1823.

support to further develop the rate. BC Hydro noted on page 21 of the Workshop 10 consideration memo that "stakeholders agree there may be merit in a freshet rate including representatives of BC Hydro's residential, General Service and Transmission Service customers".

1.77.1 Please explain whether or not BC Hydro considered making the freshet pilot available to general service rate class customers who might be able to complement BC Hydro's system advantages in offering a freshet rate and if not why not.

RESPONSE:

BC Hydro explained its reasons for not including General Service customers in the pilot program on page 46 of the Workshop 5 Consideration memo which can be found on page 122 of 292 in Appendix C-5A of Exhibit B-1. Please also refer to section 3 of Exhibit B-3.

BC Hydro continues to believe the costs of administering the pilot rate to a broad group of eligible General Service customers could be high on a $/kWh basis. BC Hydro anticipates that significant customer education may be required to obtain meaningful take-up of the rate from General Service customers. In addition, as is the case for RS 1827 customers that are ineligible for the pilot rate, a majority of larger General Service customers naturally increase consumption year over year and might benefit from the rate without a behavioural change.

77.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, Page 7-26 & 7-27

As discussed in sections 1.1.3 and 7.1 of the Application, BC Hydro is proposing to create a new optional rate (RS 1892) for non-firm service during these freshet periods. RS 1892 would be available to customers taking service under RS 1823.

support to further develop the rate. BC Hydro noted on page 21 of the Workshop 10 consideration memo that "stakeholders agree there may be merit in a freshet rate including representatives of BC Hydro's residential, General Service and Transmission Service customers".

1.77.2 Is BC Hydro aware that some general service rate class customers would be interested in such a rate and could usefully increase productivity in their businesses with access to such rates?

RESPONSE:

No General Service customer in two General Service Rate Workshops (8a/8b or 11a/11b) conveyed to BC Hydro that participating in the freshet rate pilot was a priority. Nor have any such customers approached BC Hydro concerning potential participation in the freshet rate pilot.

77.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, Page 7-26 & 7-27

As discussed in sections 1.1.3 and 7.1 of the Application, BC Hydro is proposing to create a new optional rate (RS 1892) for non-firm service during these freshet periods. RS 1892 would be available to customers taking service under RS 1823.

support to further develop the rate. BC Hydro noted on page 21 of the Workshop 10 consideration memo that "stakeholders agree there may be merit in a freshet rate including representatives of BC Hydro's residential, General Service and Transmission Service customers".

1.77.3 Will Module 2 enable discussion of interruptible non-firm rates for general service rate classes and will the freshet economic become a part of the considerations in setting such rates that would become accessible to general service customers?

RESPONSE:

In BC Hydro's Workshop 11(b) presentation (page 116 of 382 in Appendix C-4B of Exhibit B-1), BC Hydro indicated that optional General Service interruptible rates would be explored in RDA Module 2.

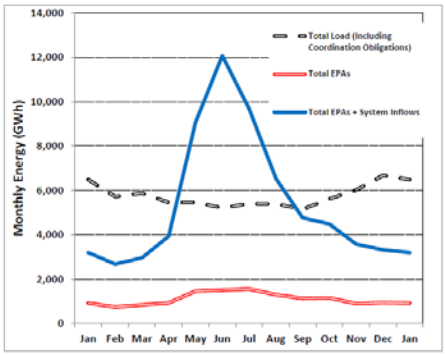
As described on page 218 of 382 of BC Hydro' Workshop 11(a)/11(b) consideration memo (Appendix C-4B of Exhibit B-1), consideration of a General Service freshet rate in Module 2 would be premature in advance of the contemplated two-year pilot for RS 1823 customers. At the conclusion of the pilot, BC Hydro will reassess which types of customers should be eligible for a freshet rate if a freshet rate becomes a permanent offering. Please also note BC Hydro's submissions in Exhibit B-3, page 7 of 19, where BC Hydro observed that no party during the 2015 RDA Stakeholder engagement process offered evidence that General Service customers can meaningfully increase consumption during the freshet period.

78.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, Page 7-28

12

Figure 7-2 System Inflows



1.78.1 Please confirm that to absorb 1000 GWh during the freshet time frame would require over 1300 MW of load for the period.

RESPONSE:

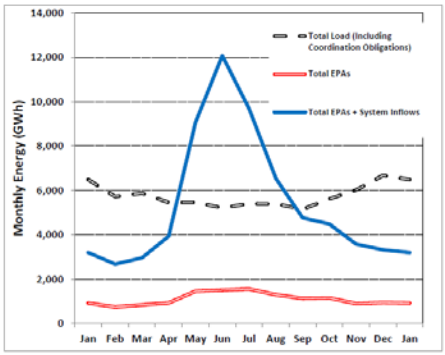
Not confirmed. 1,000 GWh equates to about 453 aMW over the May through July period.

78.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, Page 7-28

12

Figure 7-2 System Inflows



1.78.2 What is the maximum amount of energy BC Hydro would find useful to absorb during this time period in order to optimize its system, including optimization in terms of taking advantage of the Mid-C markets?

RESPONSE:

BC Hydro interprets the question to be "what are the maximum energy imports during the freshet period that optimize the value of the system?".

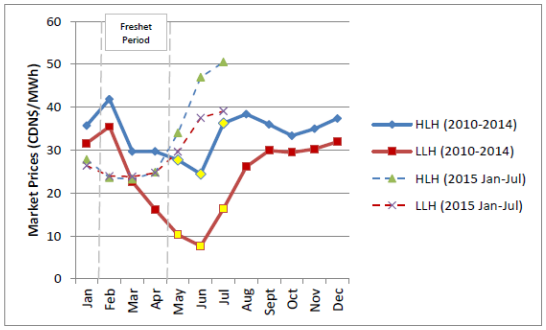
During the freshet period the combination of the energy from non-discretionary generation from the Heritage Facilities and from non-dispatchable deliveries from IPPs limits BC Hydro's ability to import energy into the system, or forces exports from the system. BC Hydro's import capability varies depending on a combination of inflows, reservoir storage space, spill risk, and the hour-by-hour load-resource balance constrained by the minimum generation requirements in the system.

During the freshet, the large amount of hydro-based generation and wind resources in the BPA control area tend to drive market prices to very low (and sometimes negative) levels. From an economic optimization perspective, U.S. Pacific Northwest freshet energy is generally the cheapest energy available in the year and maximizing imports of this energy would be optimal. However, frequently the BC Hydro system has no ability to import and store any energy during this period.

79.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, Page7-30

Figure 7-3 Five-Year Average of Mid-C Market Prices (2010 – 2014) – Updated with 2015 Prices to the End of July



1.79.1 Given that the low prices at Mid C appear to be available from March through to August and that in some years the freshet impact on prices may occur early would it not make sense for the freshet rate to be available on a more flexible basis responding to market and system conditions?

RESPONSE:

The freshet rate is targeting a period with both low market prices and constrained import/export balance. While low prices on the power markets can at times be seen outside of the traditional freshet window, the constrained import issues (and forced exports) are the result of high generation from BC Hydro non-discretionary and non-dispatchable IPP resources. The combination of low market prices and constrained import/export balance will almost exclusively occur during the melting of the winter snowpack in the May to July time period.

80.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, 7-38

22 BC Hydro considers a proxy wheeling fee of $CDN 3/MWh appropriate given the
23 cost rationale and the fact there are risks to non-participating customers. This
24 proposed fee is approximately 50 per cent of the BPA wheeling fee that BC Hydro
25 proposed at Workshop 10.

1.80.1 Please confirm that taking advantage of the freshet period is possible because of the investment in the BC Hydro electrical system, which is being paid for by BC Hydro's core customers.

RESPONSE:

Confirmed.

80.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, 7-38

22 BC Hydro considers a proxy wheeling fee of $CDN 3/MWh appropriate given the
23 cost rationale and the fact there are risks to non-participating customers. This
24 proposed fee is approximately 50 per cent of the BPA wheeling fee that BC Hydro
25 proposed at Workshop 10.

1.80.2 Please discuss why a normal as opposed to a 50% wheeling fee would not be appropriate.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.108.1.

81.0 F. Chapter 7 – Transmission Service Rate Design

Reference: Exhibit B-1, 7-40

consideration memo.[283] The benefits to participating customers relate to the price spread between the RS 1823 Tier 1 rate and Mid-C prices (discussed in section 7.3.4.2) while the benefits to non-participating customers relate to the price floor and wheeling fee (discussed in section 7.3.4.3 under the heading "Energy Charge"). BC Hydro acknowledges the rate could bring other benefits to both groups, but these have not been quantified.

1.81.1 Please confirm that this discussion is just the energy benefit and that because it would be treated as non-firm there would also be a benefit of no additional demand charges for the customer.

RESPONSE:

BC Hydro does not consider the freshet rate pilot structure of no additional demand charge for RS 1823 customer service under the freshet rate pilot as a benefit. BC Hydro is proposing the freshet rate contain no demand charge because freshet rate load is non-firm and would not be included in BC Hydro's load forecast. Accordingly, no capacity-related investments are being advanced to serve the freshet load. This treatment is consistent with BC Hydro's other interruptible rates - RS 1253 (Distribution Service – IPP Station Service), RS 1280 (Shore Power Service – Distribution), RS 1853 (Transmission Service – IPP Station Service), TS 76 (Agreement for Provision of Shore Power Service to Canada Place), RS 1880 (Transmission Service – Standby and Maintenance Supply), RS 1891 (Shore Power Service – Transmission).

82.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-10 and Exhibit G-1B

- Labour for customer service and credit agents to review files and issue the disconnection order;
- Labour for customer service or credit agents to issue a reconnection order following the reporting of a payment, for customers not electing or able to report a payment and initiate the reconnection using self-service tools; and
- Direct labour costs to manually disconnect or reconnect a service, for the proportion of disconnections and reconnections that cannot be performed remotely.

The default Minimum Reconnection Charge is applicable for any remote reconnection, as well as when a manual reconnection is performed during regular working hours. When a manual reconnection is requested by the customer outside of regular working hours, and if a crew is available to be dispatched, the overtime Minimum Reconnection Charge will apply to recover the additional costs. BC Hydro proposes to update the overtime Minimum Reconnection Charge from $158 to $280 to recover increased costs associated with a manual reconnection done on overtime hours. After-hour reconnections at call-out rates are extremely rare and so it is

Minimum Reconnection Charges

Based on the weighted average cost of service of the F2015 manual and remote reconnections.

Costs	Regular Hours	Overtime – Manual	Call Out
ABSBC (Call Centre and Credit Review)	$5.37	$5.37	
Manual Disconnection (5%)	$9.48	$9.48	
Manual Reconnection (7% for regular hours / 100% for Overtime)	$14.95	$265.47	
Total Costs	$29.80	$280.32	
Rounded Minimum Reconnection Charges	**$30**	**$280**	**Remove**

1.82.1 Please clarify the activities and time elements that are included in Manual Disconnection cost of $9.48, and the reference to the 5%.

RESPONSE:

A manual disconnection requires the dispatch of a FMA, a Meter Technician, or a PLT crew to the premises. Dispatching a FMA is the preferred option based on cost, although other resource types may be dispatched based on meter types, resource availability and proximity. The labour charge includes an average travel time and associated vehicle costs. The labour cost of the Dispatcher is also included as a separate line item.

The weighted average cost of these resources for performing a manual disconnection during normal working hours is approximately $181, as outlined in the public version of Attachment 1 to BC Hydro's response to BCUC IR 1.124.1. Five per cent of disconnections are performed manually. Therefore, on a weighted unit cost basis, a manual disconnection adds 0.05 * $181 = $9.48 to the Minimum Reconnection Charge.

82.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-10 and Exhibit G-1B

- Labour for customer service and credit agents to review files and issue the disconnection order;
- Labour for customer service or credit agents to issue a reconnection order following the reporting of a payment, for customers not electing or able to report a payment and initiate the reconnection using self-service tools; and
- Direct labour costs to manually disconnect or reconnect a service, for the proportion of disconnections and reconnections that cannot be performed remotely.

The default Minimum Reconnection Charge is applicable for any remote reconnection, as well as when a manual reconnection is performed during regular working hours. When a manual reconnection is requested by the customer outside of regular working hours, and if a crew is available to be dispatched, the overtime Minimum Reconnection Charge will apply to recover the additional costs. BC Hydro proposes to update the overtime Minimum Reconnection Charge from $158 to $280 to recover increased costs associated with a manual reconnection done on overtime hours. After-hour reconnections at call-out rates are extremely rare and so it is

Minimum Reconnection Charges

Based on the weighted average cost of service of the F2015 manual and remote reconnections.

Costs	Regular Hours	Overtime – Manual	Call Out
ABSBC (Call Centre and Credit Review)	$5.37	$5.37	
Manual Disconnection (5%)	$9.48	$9.48	
Manual Reconnection (7% for regular hours / 100% for Overtime)	$14.95	$265.47	
Total Costs	$29.80	$280.32	
Rounded Minimum Reconnection Charges	**$30**	**$280**	**Remove**

1.82.2 Please clarify the activities and the time elements that are included in the Manual Reconnection, and the reference to the 7% for regular hours, and 100% for overtime.

RESPONSE:

Similar to BC Hydro's response to CEC IR 1.82.1, a manual reconnection requires the dispatch of a FMA, a Meter Technician or a PLT crew to the premises.

Seven per cent of reconnections require the electrical service to be manually reconnected. This is multiplied by the weighted average labour cost of the reconnection (approximately $222, as described in the public version of Attachment 1 to BC Hydro's response to BCUC IR 1.124.1) to provide a contribution to the Minimum Reconnection Charge of $14.95.

If the meter cannot be reconnected remotely and is manually reconnected at the customer's request outside of normal working hours, the customer is charged 100 per cent of the weighted average manual reconnection costs, calculated using overtime labour rates. This is so the costs incurred for this customer-driven activity are not borne by other ratepayers.

82.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-10 and Exhibit G-1B

- Labour for customer service and credit agents to review files and issue the disconnection order;
- Labour for customer service or credit agents to issue a reconnection order following the reporting of a payment, for customers not electing or able to report a payment and initiate the reconnection using self-service tools; and
- Direct labour costs to manually disconnect or reconnect a service, for the proportion of disconnections and reconnections that cannot be performed remotely.

The default Minimum Reconnection Charge is applicable for any remote reconnection, as well as when a manual reconnection is performed during regular working hours. When a manual reconnection is requested by the customer outside of regular working hours, and if a crew is available to be dispatched, the overtime Minimum Reconnection Charge will apply to recover the additional costs. BC Hydro proposes to update the overtime Minimum Reconnection Charge from $158 to $280 to recover increased costs associated with a manual reconnection done on overtime hours. After-hour reconnections at call-out rates are extremely rare and so it is

Minimum Reconnection Charges

Based on the weighted average cost of service of the F2015 manual and remote reconnections.

Costs	Regular Hours	Overtime – Manual	Call Out
ABSBC (Call Centre and Credit Review)	$5.37	$5.37	
Manual Disconnection (5%)	$9.48	$9.48	
Manual Reconnection (7% for regular hours / 100% for Overtime)	$14.95	$265.47	
Total Costs	$29.80	$280.32	
Rounded Minimum Reconnection Charges	**$30**	**$280**	**Remove**

1.82.3 Please provide a breakdown of the costs for customer service for customers not electing or able to report a payment and initiate the reconnection service using self-service tools.

RESPONSE:

Please refer to the public version of Attachment 1 to BC Hydro's response to the BCUC IR 1.124.1.

82.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-10 and Exhibit G-1B

- Labour for customer service and credit agents to review files and issue the disconnection order;
- Labour for customer service or credit agents to issue a reconnection order following the reporting of a payment, for customers not electing or able to report a payment and initiate the reconnection using self-service tools; and
- Direct labour costs to manually disconnect or reconnect a service, for the proportion of disconnections and reconnections that cannot be performed remotely.

The default Minimum Reconnection Charge is applicable for any remote reconnection, as well as when a manual reconnection is performed during regular working hours. When a manual reconnection is requested by the customer outside of regular working hours, and if a crew is available to be dispatched, the overtime Minimum Reconnection Charge will apply to recover the additional costs. BC Hydro proposes to update the overtime Minimum Reconnection Charge from $158 to $280 to recover increased costs associated with a manual reconnection done on overtime hours. After-hour reconnections at call-out rates are extremely rare and so it is

Minimum Reconnection Charges

Based on the weighted average cost of service of the F2015 manual and remote reconnections.

Costs	Regular Hours	Overtime – Manual	Call Out
ABSBC (Call Centre and Credit Review)	$5.37	$5.37	
Manual Disconnection (5%)	$9.48	$9.48	
Manual Reconnection (7% for regular hours / 100% for Overtime)	$14.95	$265.47	
Total Costs	$29.80	$280.32	
Rounded Minimum Reconnection Charges	**$30**	**$280**	**Remove**

1.82.4 What are the direct labour costs to manually disconnect or reconnect a service?

RESPONSE:

Please refer to the public version of Attachment 1 to BC Hydro's response to BCUC IR 1.124.1.

82.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-10 and Exhibit G-1B

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Total Costs	$29.80	$280.32	
Rounded Minimum Reconnection Charges	**$30**	**$280**	**Remove**

1.82.5 What is an approximate proportion of disconnections and reconnections that cannot be performed remotely?

RESPONSE:

Approximately 5 per cent of disconnections are not performed remotely. These include meters that are not enabled for RDR, as well as RDR-enabled meters that do not successfully disconnect the service.

Approximately 7 per cent of reconnections are not performed remotely. These include all meters that were disconnected manually, as well as meters that were remotely disconnected but could not be successfully reconnected over the air.

83.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-8 and page 8-10

Minimum Reconnection Charge (default) – remote and manual reconnections during regular working hours and remote reconnections outside of regular working hours	30 per meter
Manual reconnection performed on overtime	280 per meter

The default Minimum Reconnection Charge is applicable for any remote reconnection, as well as when a manual reconnection is performed during regular working hours. When a manual reconnection is requested by the customer outside of regular working hours, and if a crew is available to be dispatched, the overtime Minimum Reconnection Charge will apply to recover the additional costs. BC Hydro proposes to update the overtime Minimum Reconnection Charge from $158 to $280 to recover increased costs associated with a manual reconnection done on overtime hours. After-hour reconnections at call-out rates are extremely rare and so it is

1.83.1 Please explain the difference between a call-out and a manual reconnection outside of regular working hours.

RESPONSE:

A manual reconnection outside of regular working hours is when, at the request of the customer, a resource that has already reported to work extends their working hours to perform the reconnection. For example, a FMA could be scheduled to complete his or her shift at 4 p.m. but works until 5 p.m. for the purpose of reconnect the customer.

A call-out is when a resource is asked to report to work to perform a reconnection at a time when he or she would not otherwise be working (e.g., on a Sunday).

BC Hydro normally undertakes manual disconnections for non-payment before 2 p.m., Monday to Thursday. This maximizes the likelihood that the customer can request a reconnection within normal working hours, as well as before a weekend.

Remote disconnections are performed for longer hours (until 4 p.m. Monday to Thursday and until noon on Friday) because the customer can reconnect themselves remotely once reporting a payment in the IVR phone system.

83.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-8 and page 8-10

Minimum Reconnection Charge (default) – remote and manual reconnections during regular working hours and remote reconnections outside of regular working hours	30 per meter
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The default Minimum Reconnection Charge is applicable for any remote reconnection, as well as when a manual reconnection is performed during regular working hours. When a manual reconnection is requested by the customer outside of regular working hours, and if a crew is available to be dispatched, the overtime Minimum Reconnection Charge will apply to recover the additional costs. BC Hydro proposes to update the overtime Minimum Reconnection Charge from $158 to $280 to recover increased costs associated with a manual reconnection done on overtime hours. After-hour reconnections at call-out rates are extremely rare and so it is

1.83.2 What is the overtime rate that is used to cost out the manual reconnection performed on overtime?

RESPONSE:

The overtime rate depends on the resource used for the reconnection.

Please refer to the public version of Attachment 1 to BC Hydro's response to BCUC IR 1.124.1.

83.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-8 and page 8-10

Minimum Reconnection Charge (default) – remote and manual reconnections during regular working hours and remote reconnections outside of regular working hours	30 per meter
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1.83.3 What factors contributed to the overtime rate increasing by over $120?

RESPONSE:

The primary factor is an increase in the overtime SLR for PLTs.

In addition, the methodology used in the 2015 RDA now includes costs for:

- **Credit and call centre costs, at a combined unit cost of $5.37; and**
- **Dispatcher costs, at a unit cost of $7.81.**

84.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-14 and Appendix G-1B

The current Standard Charges in section 11.3 of the Electric Tariff include a "Returned Cheque or Pre-Authorized Payment Charge" for when a customer makes a payment but it is rejected for a reason such as insufficient funds. Currently, this charge is linked to the NSF fee posted by BC Hydro's banking provider, BMO Bank of Montreal. Although BC Hydro's standard charge for a returned payment has remained at $20, the posted NSF fee has been raised several times since the 2007 RDA and is currently $40.

Miscellaneous Charges: Returned Payment Charge

Based on BC Hydro's F2015 weighted average costs of handling returned cheques and returned electronic fund transfers (EFT):

Returned Payments in F2015	
Returned Cheques	1,045
Returned EFTs	10,847
Total Returned Payments	11,892
Bank of Montreal (BMO) and Symcor charges	
Weighted average per returned payment	$1.37
ABSBC Handling Cost	
Cost per returned payment	$3.68
Customer Communication (Letter)	$1.00
Total cost of handling a returned payment	$6.05
Rounded	**$6**

1.84.1 Please provide the cost of a returned Electronic Funds transfer.

RESPONSE:

BC Hydro is charged approximately [redacted] by its bank for a returned electronic payment.

As provided by section 42 of the *ATA* and section 1 of the Commission's Confidential Filings Practice Directive, BC Hydro requests confidential filing with the Commission for the requested bank-related cost information on the basis that such information is the subject of contractual obligations, and is financial and commercial information that is confidential and has consistently been treated as confidential by BC Hydro and its bank.

84.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-14 and Appendix G-1B

The current Standard Charges in section 11.3 of the Electric Tariff include a "Returned Cheque or Pre-Authorized Payment Charge" for when a customer makes a payment but it is rejected for a reason such as insufficient funds. Currently, this charge is linked to the NSF fee posted by BC Hydro's banking provider, BMO Bank of Montreal. Although BC Hydro's standard charge for a returned payment has remained at $20, the posted NSF fee has been raised several times since the 2007 RDA and is currently $40.

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ABSBC Handling Cost	
Cost per returned payment	$3.68
Customer Communication (Letter)	$1.00
Total cost of handling a returned payment	$6.05
Rounded	**$6**

1.84.2 Please provide examples of what would represent appropriate charges if returned payment charges for cheques had a different fee (based on costs) than those for electronic funds transfers.

RESPONSE:

If different charges were applied depending on the type of transaction, and assuming that ABSBC and customer communications costs were the same in either case:

- **A returned cheque charge would be approximately $13.50; and**
- **A returned electronic payment charge would be approximately $5.00.**

85.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-16 and 8-17

In accordance with section 4.3 of the Electric Tariff, a customer that doubts the accuracy of the meter may have the meter tested by Measurement Canada.[299] There is no charge to the customer if the meter is found to be operating outside of normal parameters as described within the *Electricity and Gas Inspection Act*;[300] however in accordance with section 6.7 of the Electric Tariff, the customer is currently charged the default Minimum Reconnection Charge (currently $125) if the meter is deemed to be accurate.

option 1 - the updated default Minimum Reconnection Charge of $30; option 2 – the updated Minimum Connection Charge (First Meter) of $181 to more closely reflect cost recovery; and option 3 – the current (not updated) default Minimum Reconnection Charge of $125. No stakeholder supported option 1, but stakeholders were divided as to whether option 2 or option 3 was the best option. COPE 378 expressed concern that both option 2 and option 3 may result in some customers with legitimate concerns foregoing their right to have the meter tested out of concern they would be charged if the meter passes.

1.85.1 Is it possible for there to be a problem related to the meter installation such as it recording the wrong unit in a multi-family dwelling or other issue such that the meter operates correctly but the record is incorrect?

RESPONSE:

Yes, this situation is referred to as a "switched meter." It can arise from a number of reasons that include:

- **A customer's or developer's electrician incorrectly wiring a meter base to the wrong unit;**
- **A developer or landlord changing unit numbers or the division of units without informing BC Hydro; or**
- **BC Hydro incorrectly setting up the meter in the billing system.**

In the first and second instances, the metering would be associated with another unit in the same complex. In the third instance the meter could be associated with any account.

85.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-16 and 8-17

In accordance with section 4.3 of the Electric Tariff, a customer that doubts the accuracy of the meter may have the meter tested by Measurement Canada.[299] There is no charge to the customer if the meter is found to be operating outside of normal parameters as described within the *Electricity and Gas Inspection Act*;[300] however in accordance with section 6.7 of the Electric Tariff, the customer is currently charged the default Minimum Reconnection Charge (currently $125) if the meter is deemed to be accurate.

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1.85.1 Is it possible for there to be a problem related to the meter installation such as it recording the wrong unit in a multi-family dwelling or other issue such that the meter operates correctly but the record is incorrect?

1.85.1.1 If yes, has BC Hydro experienced any situations of this nature? Please explain.

RESPONSE:

Yes, it is not common but this situation does occur occasionally.

BC Hydro's experience is that the majority of switched meters are caused by electrician wiring errors or lack of developer/landlord notification of a change in unit configurations. However, BC Hydro sometimes makes administrative errors that lead to billing based on consumption on the wrong meter.

Switched meters are usually found when a customer notices that billed consumption is not consistent with his or her expectations (e.g., consumption recorded while the customer was away on vacation). They can also be found when one of the units is disconnected for non-payment or as a vacant premises. Unfortunately, a switched meter situation can continue for many years before it is discovered.

85.0 G. Chapter 8 – Electric Tariff Terms and Conditions

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In accordance with section 4.3 of the Electric Tariff, a customer that doubts the accuracy of the meter may have the meter tested by Measurement Canada.[299] There is no charge to the customer if the meter is found to be operating outside of normal parameters as described within the *Electricity and Gas Inspection Act*;[300] however in accordance with section 6.7 of the Electric Tariff, the customer is currently charged the default Minimum Reconnection Charge (currently $125) if the meter is deemed to be accurate.

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1.85.2 Do customers have the opportunity to discuss their concerns with a BC Hydro representative and have assistance resolving their concerns? Please explain.

RESPONSE:

Yes. When a customer contacts the call centre to discuss a high bill concern, the customer service representative typically recommends the customer perform a breaker test. If the breaker is off but the meter continues to record consumption then a switched meter is a possibility. The customer may also be asked to confirm that the meter number matches the one shown on their bill.

If the meter appears to be correctly associated with the account then continuing to perform the breaker test for each circuit can help to identify a cause of higher-than-expected consumption. The customer is also informed of online tools ad in-home displays that can be used to monitor consumption.

If from this analysis the call centre agent suspects there may be a switched meter, he or she would dispatch a FMA or Meter Technician to conduct an on-site inspection.

85.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-16 and 8-17

In accordance with section 4.3 of the Electric Tariff, a customer that doubts the accuracy of the meter may have the meter tested by Measurement Canada.[299] There is no charge to the customer if the meter is found to be operating outside of normal parameters as described within the *Electricity and Gas Inspection Act*;[300] however in accordance with section 6.7 of the Electric Tariff, the customer is currently charged the default Minimum Reconnection Charge (currently $125) if the meter is deemed to be accurate.

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1.85.3 Could a BC Hydro representative waive the fee if they accepted the customer's concerns as indicating a potential problem but the customer was concerned about the potential cost of testing? Please explain.

RESPONSE:

No. BC Hydro applies the Standard Charge in all cases of customer-requested meter tests.

BC Hydro attempts to assist the customer in diagnosing the cause of higher-than-expected consumption. BC Hydro does not have insight into how electricity is used 'behind the meter' but uses its best efforts to help the customer diagnose the perceived issue.

If during the inquiry BC Hydro believes there is a potential for a switched meter or failed meter then it dispatches a resource to investigate. However, BC Hydro is confident in the accuracy of its meters and so, in absence of evidence to the contrary, it does not facilitate customer requests for meter tests without applying the Standard Charge to recover its costs.

The only exception is if during review of an escalated complaint it is identified that the customer's request for a meter test was precipitated by an incorrect or delayed action by BC Hydro while investigating the customer's concern. In this case, the fee may be waived under the rationale that the customer could have avoided the meter test charge if BC Hydro had provided an acceptable level of customer service.

85.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-16 and 8-17

In accordance with section 4.3 of the Electric Tariff, a customer that doubts the accuracy of the meter may have the meter tested by Measurement Canada.[299] There is no charge to the customer if the meter is found to be operating outside of normal parameters as described within the *Electricity and Gas Inspection Act*;[300] however in accordance with section 6.7 of the Electric Tariff, the customer is currently charged the default Minimum Reconnection Charge (currently $125) if the meter is deemed to be accurate.

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1.85.4 Is the customer required to pay the charge up front, and receive a reimbursement if the meter does not perform properly under testing?

RESPONSE:

The customer is not charged until a test report is provided by Measurement Canada that indicates the meter is operating within normal, allowable parameters and that no other conditions existed that disprove the accuracy of billing.

86.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-23

- Billing errors – If the electric utility erred and overcharged the low income customer, it will refund the money immediately;

1.86.1 Can non low-income customers receive an immediate refund if the electric utility erred and overcharged them?

RESPONSE:

Any customer can request that a credit balance on his or her account be issued as a refund; the credit balance may be the result of an over-billing error, an over-contribution to a billing plan, the release of a security deposit, or an over-payment by the customer. Processing time for a refund cheque is normally seven to ten days.

86.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-23

- Billing errors – If the electric utility erred and overcharged the low income customer, it will refund the money immediately;

1.86.1 Can non low-income customers receive an immediate refund if the electric utility erred and overcharged them?

1.86.1.1 If not, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.86.1.

86.0 G. Chapter 8 – Electric Tariff Terms and Conditions

Reference: Exhibit B-1, page 8-23

- Billing errors – If the electric utility erred and overcharged the low income customer, it will refund the money immediately;

1.86.1 Can non low-income customers receive an immediate refund if the electric utility erred and overcharged them?

1.86.1.2 If not, does BC Hydro pay interest at the same rate as that collected for non-payment? Please explain.

RESPONSE:

As per the back-billing provisions of the Electric Tariff Terms and Conditions (section 5.8(6)), when an account has been over-billed BC Hydro is to pay interest at a rate equal to its WACD calculated for BC Hydro's most recent fiscal year. This is the same rate that is used to calculate the borrowing cost component in the derivation of the Late Payment Charge.

CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES UNION, LOCAL 378 (COPE 378)

INFORMATION REQUEST NO. 1 TO BC HYDRO

BC HYDRO 2015 RATE DESIGN

1.0 Reference: Exhibit B-1, Application, 1.3 Relationship of Rate Design to BC Hydro's Revenue Requirement and Integrated Resource Plan, page 1-17, ll 10-11

BC Hydro 2013 IRP, Chapter 3

"The main link between the 2013 IRP and this Application is with respect to BC Hydro's LRMC."

However, two of the resource options considered in the 2013 IRP (DSM options 4 and 5) were aimed at incenting more DSM than what is included in BC Hydro's current plan. Option 4 contemplated new and more aggressive conservation rate structures but the enhanced DSM options were not pursued because they were considered too 'new and untested' and raised uncertainty as to their effectiveness.

1.1 Please confirm the key elements of the conservation rate structures in the IRP's DSM Option 4 included:

(i) All customers would have experienced greater exposure to marginal cost price signals;

(ii) The transmission service tier 1/tier 2 rate split was set at 80/20 instead of the current 90/10;

(iii) General customer rates or connection fees were tied to efficiency ratings; and

(iv) Rate structures for houses and buildings were tied to energy performance standards.

1.2 Given the widespread support to use economically efficient DSM as opposed to supply-side projects and initiatives to address growing needs, what steps, if any, has BC Hydro taken in the 2015 RDA to develop and test any of these four key elements of the IRP's DSM Option 4 in order to allay any potential concerns about their viability in the future?

2.0 Reference: Exhibit B-1, Application, 1.3 Relationship of Rate Design to BC Hydro's Revenue Requirement and Integrated Resource Plan, page 1-20 to 1-21 and 2-14

The three Bonbright criteria BC Hydro lists as its top rate priorities in this RDA do not include the Bonbright efficiency criterion that speaks to price signals that encourage conservation and discourage inefficient use.

2.1 Please explain why BC Hydro does not consider the encouragement of conservation and efficient energy use with appropriate price signals as one of its priorities.

2.2 On page 2-14 of the Application, BC Hydro states that it does not believe the 2007 Energy Plan Action 4 (which called for rate structures to encourage energy efficiency and conservation) requires it to prioritize the Bonbright efficiency criterion over the other seven. Does BC Hydro think the decision to prioritize other Bonbright criteria over the efficiency one is inconsistent with the 2007 Energy Plan?

2.2.1 If yes, please explain why BC Hydro is proceeding on this basis.

2.2.2 If no, please explain why it is not inconsistent.

3.0 Reference: Exhibit B-1, Application, 2.2.1.3 Direction No. 7, the Heritage Contract and Rate Rebalancing, page 2-7, ll 1-17 and page 2-15

BC Hydro notes that Special Direction No. 7 dictates a Tier 1/Tier 2 90/10 split for transmission service rates.

3.1 Has BC Hydro provided any analysis or briefing of the energy conservation and other consequences of a movement to an 80/20 split to government?

3.1.1 If so, please provide.

3.2 Has government provided any analysis comparing an 80/20 split versus a 90/10 one to explain why BC Hydro has been directed to maintain a 90/10 split?

3.2.1 If so, please provide.

3.3 Please provide an analysis of the conservation and efficient energy use implications of the 80/20 split developed for DSM Option 4 of the 2013 IRP.

4.0 Reference: Exhibit B-1, Application, 2.2.2 Government Policy, page 2-8, ll 22-23

BC Hydro states that it is government policy that there will be no mandatory Time of Use (TOU) pricing for residential and commercial customers.

4.1 Does BC Hydro consider this government policy to be a legally binding constraint?

4.1.1 If so, please explain why BC Hydro is legally bound by this policy.

4.1.2 If not, please explain why not.

4.2 Has BC Hydro analyzed what impacts TOU rates might have on peak demand and the integration of intermittent renewable supply?

4.2.1 If so, please provide that analysis.

4.2.2 If not, please explain why has BC Hydro failed to complete such an analysis?

4.3 Has BC Hydro analyzed what other possible impacts TOU rates might have on its operations?

4.3.1 If so, please provide that analysis.

4.3.2 If not, please explain why BC Hydro has failed to complete such an analysis.

4.4 Has government provided to BC Hydro any analysis of TOU rates?

4.4.1 If so, please provide.

4.4.2 If not, please explain BC Hydro's understanding of what government used to inform its position prohibiting TOU rates.

5.0 Reference: Exhibit B-1, Application, 2.3.2.1 Smart Meters, pages 2-44 to 2-46

BC Hydro states that the installation of Smart Meters is 99% complete and that these new assets have helped the utility to better understand load characteristics, enabling it to develop more accurate cost allocations.

> "The additional data from smart metering has increased the accuracy of BC Hydro's load profile information which is a key input into cost allocation with the F2016 COS study. With the capability to create almost on-demand detailed customer load profiles, COS analysis, rate design and peak load forecasting can be improved." (page 2-45)

5.1 Has BC Hydro studied what improvements in rate design Smart Meters may enable?

5.1.1 If so, please provide those relevant studies, documents, or summaries.

5.1.2 If not, why has BC Hydro failed to study this?

5.2 Has BC Hydro studied the opportunities to use Smart Meters to implement rates and controls that will enable customers to utilize price or system sensitive Smart Energy Management Technology?

5.2.1 If yes, please provide the relevant studies, documents, or summaries.

5.2.1.1 If yes, please indicate how these opportunities have influenced the development of the rate and other proposals in this RDA.

5.2.1.2 Please also indicate what opportunities identified BC Hydro has declined to pursue and apply in this RDA and explain why the utility has done so.

5.2.2 If no, why has BC Hydro failed to study this?

6.0 Reference: Exhibit B-1, Application, 2.3.2.3 Capacity Long-Run Marginal Cost, page 2-55, ll ll 11-18

"Several Workshop 3 participants advanced two grounds for including a generation capacity value in the energy LRMC for purposes of the RIB Step 2 rate: (1) the RIB rate contains no demand charge; and (2) while the RIB is an energy conservation rate, it delivers anticipated capacity savings. In section 4.1.2 of the Workshop 3 consideration memo (copy at Appendix C-3A), BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction."

6.1 Please confirm that for the foreseeable future BC Hydro is more likely to be capacity constrained as opposed to energy constrained.

6.1.1 If this is not the case, please explain the basis upon which BC Hydro has determined it is more likely to be energy constrained than capacity constrained in the near future. If this is based on studies or data not already on the record, please file those materials.

6.2 Does BC Hydro agree that reductions in peak capacity can have significant trade and other system benefits?

6.2.1 If so, please describe those benefits

6.2.2 If not, please explain why BC Hydro does not see any such benefits arising out of a reduction in peak capacity.

6.3 Since BC Hydro does not believe that it is appropriate to add a capacity value to the Step 2 RIB rate, how does the utility propose to provide a signal, price or otherwise, to customers of their marginal capacity costs or values in order to encourage efficiencies and reductions in peak requirements?

6.3.1 Please file the documents, studies, or summaries BC Hydro used to formulate its position on whether it was appropriate to provide a signal and what form that signal would or could take.

7.0 Reference: Exhibit B-1, Application, 5.2.2.2 Residential Class Characteristics, page 5-10, ll 5 5-10

"The consumption per account is generally highest for SFDs with a median consumption of about 9,800 kWh/year and a median F2016 annual electricity bill of about $900. In comparison, apartments and condominiums generally have the lowest consumption per account with a median consumption of about 3,700 kWh/year and a median F2016 annual bill of about $360."

7.1 Does BC Hydro consider it consistent with the Bonbright fairness criterion to have the same Step 1 / Step 2 breakpoint set for SFDs and apartments/condos given the fact that they each have markedly different median electricity consumptions?

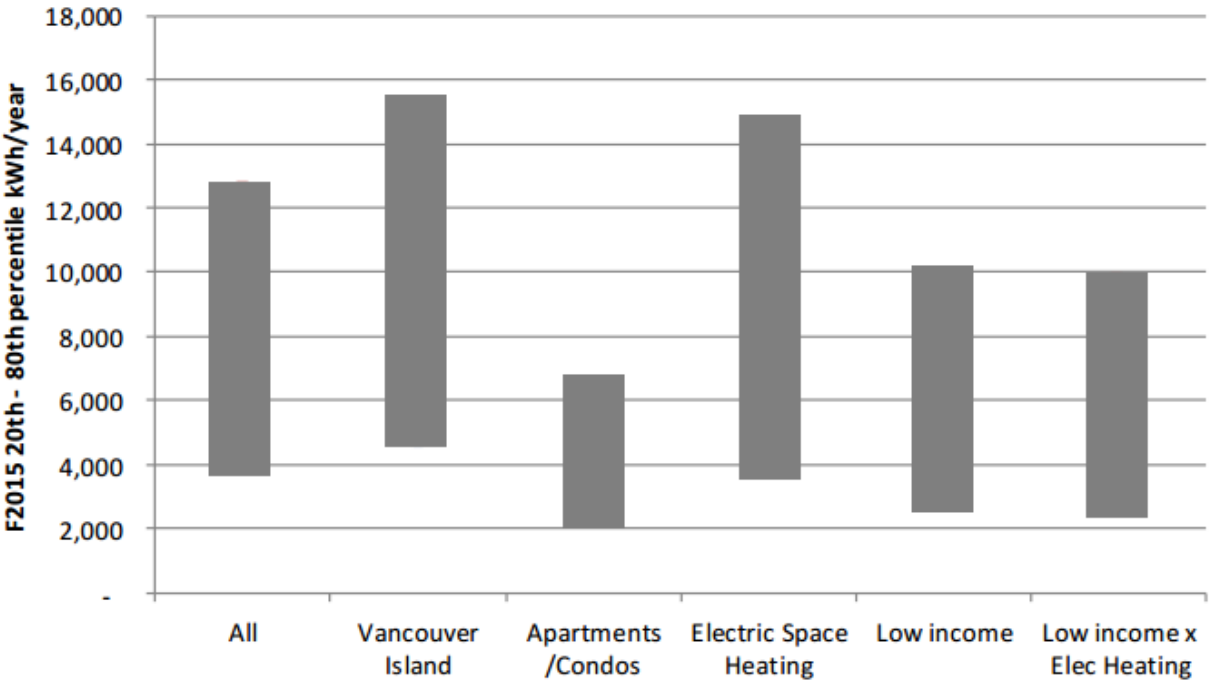
7.1.1 If yes, please explain how this is consistent with the fairness criterion.

7.2.1 If no, please explain why BC Hydro has not adjusted its Step 1 / Step 2 breakpoints for these two dwelling types in order to ensure the RIB is more fair?

8.0 Reference: Exhibit B-1, Application, 5.2.2.2 Residential Class Characteristics, page 5-12, line 8 and page 5-16, Figure 5-12

"The median consumption of low income accounts is about 5,297 kWh/year…"

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



8.1 Please confirm that the median electricity consumption for low income customers is 43% higher than the median consumption for apartments and condos.

8.2 Please confirm that the consumption range for low income customers is much broader than the range for apartments / condos.

8.3 Please confirm that this higher median consumption is due to the significant number of low income customers who live in single family dwellings (SFDs).

8.4 Table 5-15 on page 5-68 of the Application shows the percentage of each dwelling type held by low income customers. Please provide

i) the number of low income customers by dwelling type; and

ii) the number of customers defined as low income for the purposes of DSM programming (1.3 times the LICO rate) by dwelling type.

8.5 BC Hydro has stated and the BCUC has confirmed in previous decisions that the RIB rate structure benefits the majority of low income customers. Please confirm that the extent of that benefit varies considerably between low income customers living in SFDs and those living in apartments/condos.

8.6 Please confirm that for low income customers in the higher end of the household electricity consumption range, the RIB rate does nothing to ease the burden of those energy costs.

8.6.1 If not, please explain how it eases this burden.

9.0 Reference: Exhibit B-1, Application, 5.2.3 2013 Residential Inclining Block Rate Evaluation Report, page 5-17, ll 11-14

- The class average elasticity due to RRA rate increases under a flat rate was not able to be estimated using empirical data. The evaluation used the assumption of -0.05 as the class average price elasticity to determine the natural conservation baseline.

9.1 Is there an empirical basis for the assumption that in the absence of a RIB rate, the elasticity of demand for BC Hydro customers since the RIB came into effect would have been -0.05?

9.2 Please provide any materials that BC Hydro used to inform this assumption.

10.0 Reference: Exhibit B-1, Application, 5.2.3 2013 Residential Inclining Block Rate Evaluation Report, pages 5-17 to 5-18

The 2013 RIB Evaluation Report found that large consumers have higher elasticities than smaller consumers. Refer to the following 2013 RIB Evaluation Report findings:

- Large residential users consuming more than 2,400 kWh bi-monthly show a substantially higher than average response to higher prices. The 2013 RIB Evaluation Report indicates that the customer segment above 2,400 kWh of bi-monthly consumption has an estimated price elasticity of -0.16 to -0.18 (RIB Evaluation Report, pages vi, 20);
- Price elasticity is generally larger for customer segments with higher consumption. As discussed in section 5.2.2.2 above, customers living in single family detached homes generally have higher consumption than those living in other dwelling types. The 2013 RIB Evaluation Report finds that customers living in single family detached houses demonstrate higher price responsiveness than customers living in town houses, apartments or mobile homes (2013 RIB Evaluation Report, pages vi, 19). Section 5.2.2.2 also shows that customers with electric heat tend to have higher consumption than those that use other heating fuels. Price elasticity is higher among households with electric heat than those with non-electric heat (2013 RIB Evaluation Report, pages vi, 20); and
- Higher consumption is correlated with both higher awareness of the RIB rate and higher price elasticity; however, no firm conclusions can be drawn about how RIB awareness is related to customer price response (RIB Evaluation Report, pages vii, 28).

These results are all consistent with the RIB rate design assumptions that customers with a higher level of consumption tend to have a higher responsiveness to price.

10.1 Please confirm that with the RIB, high-use customers pay a higher average rate per kWh than they would if they were low-use customers?

10.2 Has BC Hydro done any analysis to determine if it is the higher average rate per kWh or the effect of the marginal rate (the tier structure) that has the greatest effect on high-use customer behaviours in the RIB?

10.2.1 If so, please provide.

10.2.2 If not, please explain why BC Hydro has chosen not to determine what has the greater effect on customer behaviours.

11.0 Reference: Exhibit B-1, Application, 5.2.5.2 Basic Charge Cost Recovery Increase, page 5-41, line 10

"The current RIB rate basic charge recovers 45 per cent of customer-related costs."

11.1 Please confirm that this figure represents the percentage recovery of fully allocated embedded costs.

11.2 Please confirm that the impact of residential customer additions on all BC Hydro customer-related costs (i.e. the marginal customer-related cost associated with serving more customers) is much less than the average fully allocated embedded costs.

11.3 Please provide BC Hydro's best estimate of the marginal customer-related cost associated with serving more customers (marginal cost per additional account).

11.4 What impact would a revenue neutral elimination of the basic charge (where the lost basic charge revenue is recovered from higher energy rates) have on the following:

(i) the step 1 and step 2 rates assuming they were both increased proportionately;

(ii) the step 1 and step 2 rates assuming that the lost customer charge revenue was recovered from the step 1 rate;

(iii) conservation of electricity (under both step rate assumptions listed above);

(iv) the average low income customer's bill (under both step rate assumptions listed above)

11.5 What impact would eliminating the basic charge for only BC Hydro's low income customers on a revenue neutral basis have on the step 1 and step 2 rates, conservation and the average bill of low income families (as listed in points (i) to (iv) in Q.4 above above).

12.0 Reference: Exhibit B-1, Application, 5.4 Low Income Rate, page 5-58, ll 3-7

"In the context of UCA sections 58 to 61 rate setting, low income rates are likely to be seen as unduly preferential to low-income customers or unduly discriminatory to the remaining customers who subsidize those rates because the low income rate would be based on the

personal characteristics of the customer, divorced from the cost to deliver electricity to the premises."

12.1 Please explain whether BC Hydro believes the RIB rate, which results in different cost recovery for people living in apartments/ condos as compared to single family dwellings (their personal housing characteristics), is any less 'unduly discriminatory' than a rate designed to lower energy costs for low income customers.

13.0 Reference: Exhibit B-1, 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, page 5-71, ll 14-21 and pages 5-71 and 5-72 lines 23-27

- As the RIB rate has been in place for almost seven years, the only sound method to gauge bill impacts to low income customers is to compare the RIB rate to an alternative had the RIB rate not been in place. BC Hydro proposes that the flat energy rate modelled for the 2015 stakeholder engagement process and described in section 5.2.4.1 above serve as the counter-factual. As noted in Table 5-3 above, BC Hydro estimates that with a flat rate, in F2017 80 per cent of low income accounts will experience bill impacts greater than 10 per cent, and 47 per cent greater than 20 per cent.

Minister RIB Report Letter Question 3

As illustrated in section 5.2.4.1 above, BC Hydro modelled the bill impacts of moving from the RIB rate to a flat rate by dwelling type (apartments) and for customers using electric space heating. BC Hydro also proposes to model the bill impacts of moving from the RIB rate to a flat rate for customers in communities that do not have access to natural gas.

13.1 Has BC Hydro identified and analyzed alternative rate structures or measures in order to identify opportunities to assist low income customers?

13.1.1 If so, please provide the materials generated.

13.1.2 If not, please explain why BC Hydro has declined to perform this analysis.

13.2 Does BC Hydro agree that there are rate structures or measures designed to assist low income customers that could do so in a more comprehensive, fair and consistent manner than the current RIB?

13.2.1 If not, please explain.

14.0 Reference: Exhibit B-1, Application, 6.2.3.1 SGS Rate Structure, pages 6-10 to 6-11

"A SGS demand charge would also require a demand meter which not all SGS customers have. The requirement for a demand meter on all SGS customers makes the demand charge less practical and cost-effective to administer."

14.1 Has BC Hydro analyzed what capabilities Smart Meters provide for better alignment of rates with costs? For example, has it analyzed whether its Smart Meters are capable of metering energy use on a Time-of-Use basis that would enable, should government policy allow, differential rates for peak versus non-peak hours and on a seasonal basis? If so please provide the relevant studies or summaries

14.2 Does BC Hydro agree that this pricing model would address some of the efficiency and fairness rationales of demand charges?

14.2.1 If not, please explain why not.

15.0 Reference: Exhibit B-1, Application, 6.2.4 BC Hydro Proposal and Stakeholder Engagement, page 6-12, ll 21-24

In BC Hydro's view, there are no rate design objectives to be traded off. Increasing the SGS basic charge recovery to 45 per cent of customer-related costs aligns with the Bonbright fairness criterion by matching embedded cost recovery in rates with cost causation. Moreover, there is no conflict with the economic efficiency criterion:

15.1 Please provide BC Hydro's best estimate of the marginal customer-related cost associated with serving more SGS customers (marginal cost per additional account).

15.2 How does that compare to the average embedded fully allocated costs per account?

16.0 Reference: Exhibit B-1, Application, 6.3.5 BC Hydro Proposal and Stakeholder Engagement, page 6-32, ll 11-15 and page 6-37

"BC Hydro acknowledged that as a result of the proposed increase to the demand charge, the MGS flat energy rate under its proposal drops below the lower bound of the energy LRMC range (F2017: MGS flat energy rate is 8.54 cents/kWh and the lower end of the energy LRMC range is 9.46 cents/kWh)."

On page 6-37, BC Hydro notes that high load-factor customers who can make more efficient use of the system will benefit the most from this proposal and that AMPC supported a higher demand charge and lower energy rate.

16.1 What analysis has BC Hydro done to compare the efficiency and conservation losses that will result from lower energy rates relative to the efficiency gain resulting from the higher demand rates?

16.2 Is there any evidence of an overall economic efficiency gain or loss?

16.2.1 If so, please provide.

17.0 Reference: Exhibit B-1, Application, 6.4.4.2 Screening of Alternatives and Stakeholder Engagement, page 6-55, ll 4-9

"However, there is a trade-off between the customer understanding and acceptance and the economic efficiency criteria because the flat energy rate would not be reflective of LRMC (F2017: LGS flat energy rate is 5.37 cents/kWh with demand charge cost recovery at 65 per cent, and the lower end of the energy LRMC range is 9.46 cents/kWh)."

17.1 Has BC Hydro estimated the efficiency (and conservation) impact of having an energy rate roughly 40% below the lower bound of the LRMC? For example has it estimated the how much higher LGS energy demand will be at its proposed energy rate as compared to a mid-point estimate of the LRMC?

17.2 Does BC Hydro have any plans to address the potential adverse efficiency impacts of having an energy rate so far below the LRMC?

17.2.1 If so please indicate what they are.

17.2.2 If not, please indicate why not.

18.0 Reference: Exhibit B-1, Application, 6.4.4.2 Screening of Alternatives and Stakeholder Engagement, page 6-56, ll 71-21

During the stakeholder engagement process, AMPC stated that the Bonbright fairness criterion supports increasing the LGS demand cost recovery to 65%. BC Hydro's proposal is to increase the LGS demand cost recovery to 65%.

18.1 What analysis has BC Hydro done to assess whether this proposal would be supported by the Bonbright efficiency criterion? More specifically, similar to questions posed concerning the proposed increase in the MGS demand rate, what analysis has BC Hydro done to compare the efficiency (and conservation) loss from lower LGS energy rates relative to the efficiency gain resulting from higher demand rates?

18.1.1 If BC Hydro has not done any analysis to assess this, please explain why not.

18.2 Is there any evidence of an overall economic efficiency gain or loss?

18.2.1 If so, please provide.

19.0 Reference: Exhibit B-1, Application, 6.4.5.1 LGS Flat Energy Rate, page 6-60, ll 18-20

"…the gains in simplification in moving to a flat energy rate appear to be worth the apparent small loss in economic efficiency in the status quo LGS rate design."

19.1 What is BC Hydro's latest available estimate of the economic conservation potential in the LGS section expressed both in GWh and as a percentage of total load?

19.2 What was BC Hydro's estimate of the extent to which that economic conservation potential might be realized under the rate proposals in the DSM Option 4 from BC Hydro's 2013 IRP?

19.3 What economic conservation potential is expected to be realized with the rates proposed in this Application?

20.0 General Issues Raised at the Workshops

During the RDA workshops, in response to a COPE 378 query, BC Hydro stated that they are approximately 5 to 10 years away from developing the necessary IT infrastructure to engage in complex billing practices such as pre-paid billing or automatic conservation incentives based on previous power use.

20.1 Can BC Hydro describe in more detail what it will achieve and when during that timeline?

20.2 Is an expansion of the online customer service and billing infrastructure currently underway?

20.2.1 If so, what is the expansion going to achieve or facilitate relating to complex billing practices.

20.3 Is an expansion relating to billing practices planned for the future?

20.3.1 If so, what is the timeline to begin and finish this expansion and what is its specific intended purpose?

20.4 What is the reason for such a lengthy timeline?

20.5 Has BC Hydro considered any of the following more flexible or conservation-oriented rate design forms, and if so, what have they determined about each:

i) rebates or incentives for demonstrated conservation;

ii) time of use and other efficient or price-responsive demand options;

iii) residential demand charges or minimum bills;

iv) micro-loans built into rates for efficiency improvements; and

v) pre-paid accounts.

20.5.1 Does BC Hydro intend to pursue investigations or development of programs in any of these areas for inclusion in future rate design applications?

20.5.1.1 If so, when is BC Hydro planning to do so?

20.5.1.2 If not, please explain why not.

20.6 In conjunction with conservation-oriented rate design, is BC Hydro considering any incentive or funding programs for retrofitting, efficiency systems, and other conservation-based upgrades?

20.6.1 Is BC Hydro considering the implementation of any of the programs listed above to enhance existing programs or to offset efficiency trade-offs inherent in the current proposal?

1.0 Reference: Exhibit B-1, Application, 1.3 Relationship of Rate Design to BC Hydro's Revenue Requirement and Integrated Resource Plan, page 1-17, ll 10-11
BC Hydro 2013 IRP, Chapter 3

"The main link between the 2013 IRP and this Application is with respect to BC Hydro's LRMC."

However, two of the resource options considered in the 2013 IRP (DSM options 4 and 5) were aimed at incenting more DSM than what is included in BC Hydro's current plan. Option 4 contemplated new and more aggressive conservation rate structures but the enhanced DSM options were not pursued because they were considered too 'new and untested' and raised uncertainty as to their effectiveness.

1.1.1 Please confirm the key elements of the conservation rate structures in the IRP's DSM Option 4 included:

(i) All customers would have experienced greater exposure to marginal cost price signals;
(ii) The transmission service tier 1/tier 2 rate split was set at 80/20 instead of the current 90/10;
(iii) General customer rates or connection fees were tied to efficiency ratings; and
(iv) Rate structures for houses and buildings were tied to energy performance standards.

RESPONSE:

Not confirmed. DSM Option 4 did not entail exposing all BC Hydro customers to marginal cost price signals; this was an element of the even more aggressive DSM Option 5. Refer to the 2013 IRP, section 3.3.1.4; https://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/november-2013-irp.html.

DSM Option 4 encompassed:

- **The Transmission Service RS 1823 Tier 1/Tier 2 rate split would be set at 80/20 instead of the current 90/10;**

- **Each industrial customer would need to meet a government-mandated, certified, plant minimum efficiency level to take advantage of BC Hydro's Heritage hydroelectric lower priced electricity; otherwise, electricity would be supplied at higher marginal rates;**

- **General Service customers would be subject to efficiency-based pricing through either connection fees tied to building energy performance or an initial baseline rate structure for new buildings; and**

- **Residential Service rates would be tied to a house's rated energy performance.**

As referenced in the preamble to this IR, BC Hydro concluded that DSM Option 4 is not viable at this time. Option 4 and 5 were developed to help further the discussion on DSM planning in the 2013 IRP. Option 4 and 5 were considered to be too conceptual and as a result were not considered viable by BC Hydro for resource planning. Among other things:

- **As discussed with COPE 378 at the meeting of June 29, 2015, the timeframe is very long, between 10 and 15 years, for the development of General Service and/or Residential rates linked to efficiency ratings or measures. Refer to the summary notes of the June 29, 2015 meeting, Exhibit B-1, Appendix C-3D, page 56 of 67, question No. 3 and references to Workshop 11b slide deck; and**

- **The industrial rate(s) entailing meeting a government-mandated, certified, plant minimum efficiency level to take advantage of BC Hydro's Heritage hydroelectric lower priced electricity raises the issue of the Heritage Contract at both a political and a regulatory level and in particular the basis for distributing the low embedded cost of service Heritage hydroelectric resource energy among BC Hydro's existing and future customers. The MEM Policy Letter confirmed that the benefits of the Heritage hydroelectric resources should continue to accrue to all BC Hydro customers on the basis of their energy consumption and peak demand, and that the benefits should not be re-allocated between customer groups on a different basis (such as efficiency ratings). A copy of the MEM Policy Letter is found at Exhibit B-1, Appendix C-1C.**

1.0 Reference: Exhibit B-1, Application, 1.3 Relationship of Rate Design to BC Hydro's Revenue Requirement and Integrated Resource Plan, page 1-17, ll 10-11
BC Hydro 2013 IRP, Chapter 3

"The main link between the 2013 IRP and this Application is with respect to BC Hydro's LRMC."

However, two of the resource options considered in the 2013 IRP (DSM options 4 and 5) were aimed at incenting more DSM than what is included in BC Hydro's current plan. Option 4 contemplated new and more aggressive conservation rate structures but the enhanced DSM options were not pursued because they were considered too 'new and untested' and raised uncertainty as to their effectiveness.

1.1.2 Given the widespread support to use economically efficient DSM as opposed to supply-side projects and initiatives to address growing needs, what steps, if any, has BC Hydro taken in the 2015 RDA to develop and test any of these four key elements of the IRP's DSM Option 4 in order to allay any potential concerns about their viability in the future?

RESPONSE:

BC Hydro has not taken any steps to develop and test the rate structure components of DSM Option 4 because as set out in BC Hydro's response to COPE IR 1.1.1, those rate structures are not viable for the foreseeable future.

2.0 Reference: Exhibit B-1, Application, 1.3 Relationship of Rate Design to BC Hydro's Revenue Requirement and Integrated Resource Plan, page 1-20 to 1-21 and 2-14

The three Bonbright criteria BC Hydro lists as its top rate priorities in this RDA do not include the Bonbright efficiency criterion that speaks to price signals that encourage conservation and discourage inefficient use.

1.2.1 Please explain why BC Hydro does not consider the encouragement of conservation and efficient energy use with appropriate price signals as one of its priorities.

RESPONSE:

As noted in BC Hydro's response to BCUC IR 1.6.1, a number of factors underpin the 2015 RDA prioritization. In the context of the overall 2015 RDA, the reduced need for energy and capacity is one of the factors leading BC Hydro to prioritize customer understanding and acceptance and stable rates for customers over the Bonbright efficiency criterion. The reduced forecasted energy and capacity need enabled BC Hydro to take stock of existing rates introduced between 2006 and 2010 to achieve energy conservation, and to prioritize minimizing unexpected changes by proposing replacement or amendment of only those rates that clearly do not the meet customer understanding and acceptance criterion:

- **Both the default Residential RIB rate and default Transmission Service RS 1823 are performing as expected, and send marginal cost price signals; and**

- **The existing two-part MGS and LGS rates are not performing as expected, and accordingly BC Hydro proposes different default rate structures for its MGS and LGS customers.**

Please refer to BC Hydro's response to BCUC IR 1.6.1 for additional detail.

2.0 Reference: Exhibit B-1, Application, 1.3 Relationship of Rate Design to BC Hydro's Revenue Requirement and Integrated Resource Plan, page 1-20 to 1-21 and 2-14

The three Bonbright criteria BC Hydro lists as its top rate priorities in this RDA do not include the Bonbright efficiency criterion that speaks to price signals that encourage conservation and discourage inefficient use.

1.2.2 On page 2-14 of the Application, BC Hydro states that it does not believe the 2007 Energy Plan Action 4 (which called for rate structures to encourage energy efficiency and conservation) requires it to prioritize the Bonbright efficiency criterion over the other seven. Does BC Hydro think the decision to prioritize other Bonbright criteria over the efficiency one is inconsistent with the 2007 Energy Plan?

1.2.2.1 If yes, please explain why BC Hydro is proceeding on this basis.
1.2.2.2 If no, please explain why it is not inconsistent.

RESPONSE:

Yes, BC Hydro is of the view that the 2015 RDA aligns with the 2007 Energy Plan.

Policy Action 4 of the 2007 Energy Plan called on BC Hydro to explore new rate structures that encourage energy conservation; this BC Hydro did between 2008 (RIB rate introduction) and 2010 (MGS/LGS two-part baseline rate introduction). As noted in BC Hydro's response to COPE IR 1.2.1, the reduced forecasted energy and capacity need enabled BC Hydro to take stock of existing rates introduced between 2006 and 2010 to achieve energy conservation. As part of 2015 RDA Module 1, BC Hydro proposes continuing with the Residential RIB rate, as it is performing as expected and sends marginal cost price signals. The existing two-part MGS and LGS rates are not performing as expected, and accordingly BC Hydro proposes different default rate structures for its MGS and LGS customers.

RDA Module 2 will explore potential General Service and Residential rate options that may encourage conservation. For example:

- **As noted at Exhibit B-1, page 1-23, a voluntary Residential pre-payment option. As noted in the Workshop 9a/9b consideration memo at section 6.1.2 (Exhibit B-1, Appendix C-3B, page 348 of 609, there may be conservation benefits associated with a prepayment option because Residential customers who use payment options are more cognizant of their electricity use; and**

- **CEC has proposed exploration of an efficiency rate credit option for General Service customers. There are a number of building blocks to be established before developing an efficiency rate credit potentially linked to efficiency ratings or measure; refer to the Workshop 8a/8b consideration memo, section 6.3.2, pages 214 to 215 of 813 (Exhibit B-1, Appendix C-4A) for how this work is being informed by BC Hydro's Electricity Conservation and Efficiency Advisory Committee.**

3.0 Reference: Exhibit B-1, Application, 2.2.1.3 Direction No. 7, the Heritage Contract and Rate Rebalancing, page 2-7, ll 1-17 and page 2-15

BC Hydro notes that Special Direction No. 7 dictates a Tier 1/Tier 2 90/10 split for transmission service rates.

1.3.1 Has BC Hydro provided any analysis or briefing of the energy conservation and other consequences of a movement to an 80/20 split to government?

1.3.1.1 If so, please provide.

RESPONSE:

As noted in the Workshop 5 consideration memo, Exhibit B-1, Appendix C-5A, pages 147 to 148 of 292, the potential movement to a RS 1823 Tier 1/Tier 2 80/20 split was part of DSM Option 4, assessed as part of the 2013 IRP submitted to and approved by the LGIC in November 2013. The LGIC approved BC Hydro's use of DSM Option 2 as the basis for the DSM target, and as part of the approval confirmed that the rate structure components of DSM Option 4 should not be pursued at this time.

BC Hydro respectfully declines to respond to the remainder of the COPE 378 1.3 IR series on the basis that the requested information is not relevant and cannot assist the Commission with the adjudication of 2015 RDA Module 1:

- **As noted in the preamble to this IR, the result of subsection 3(1) of Direction No. 7 is that the Commission cannot unilaterally change the RS 1823 Tier 1/Tier 2 90/10 spit; and**

- **At Workshop 10, BC Hydro confirmed that the B.C. Government had no plans to refer the RS 1823 Tier 1/Tier 2 90/10 split to the Commission for a section 5 *UCA* review. The MEM Policy Letter reiterates this: 'Government is of the view that the RS 1823 Tier 1/Tier 2 90/10 split is working well and will not be referring the RS 1823 Tier 1/Tier 2 90.10 split to the British Columbia Utilities Commission for review and reporting through a section 5 [*UCA*] process" (copy at Exhibit B-1, Appendix C-1C, page 2 of 2).**

3.0 Reference: Exhibit B-1, Application, 2.2.1.3 Direction No. 7, the Heritage Contract and Rate Rebalancing, page 2-7, ll 1-17 and page 2-15

BC Hydro notes that Special Direction No. 7 dictates a Tier 1/Tier 2 90/10 split for transmission service rates.

1.3.2 Has government provided any analysis comparing an 80/20 split versus a 90/10 one to explain why BC Hydro has been directed to maintain a 90/10 split?

1.3.2.1 If so, please provide.

RESPONSE:

BC Hydro respectfully declines to respond to these questions on the basis set out in BC Hydro's response to COPE 378 IR 1.3.1.

3.0 Reference: Exhibit B-1, Application, 2.2.1.3 Direction No. 7, the Heritage Contract and Rate Rebalancing, page 2-7, ll 1-17 and page 2-15

BC Hydro notes that Special Direction No. 7 dictates a Tier 1/Tier 2 90/10 split for transmission service rates.

1.3.3 Please provide an analysis of the conservation and efficient energy use implications of the 80/20 split developed for DSM Option 4 of the 2013 IRP.

RESPONSE:

BC Hydro respectfully declines to respond to this question on the basis set out in BC Hydro's response to COPE 378 IR 1.3.1.

4.0 Reference: Exhibit B-1, Application, 2.2.2 Government Policy, page 2-8, ll 22-23

BC Hydro states that it is government policy that there will be no mandatory Time of Use (TOU) pricing for residential and commercial customers.

1.4.1 Does BC Hydro consider this government policy to be a legally binding constraint?

1.4.1.1 If so, please explain why BC Hydro is legally bound by this policy.
1.4.1.2 If not, please explain why not.

RESPONSE:

The Deputy Minister[1] 2011 *Review of BC Hydro* (2011 Review) was clear: "… the government has directed that mandatory differential pricing will not be implemented" (page 85). The 2011 Review is not lawfully binding on BC Hydro or the Commission. However, BC Hydro notes:

1. **No participant in the 2015 RDA stakeholder engagement process spanning May 2014 to September 2015 advocated for a mandatory default TOU rate for either Residential customers or General Service customers as alternatives to the existing RIB, SGS, MGS and LGS rates. For example:**

   a. **COPE 378's Workshop 3-related written feedback: "Whether voluntary or not, TOU is a bad idea when a RIB is already in place but the Union asserts that initiating this voluntary format is the thin edge of moving towards a mandatory one and that is not something COPE wishes to see happen" (Workshop 3 consideration memo, Exhibit B-1, Appendix C-3A, page 178 of 184); and**

   b. **BCOAPO's written comments in respect of Workshop 3: "TOU rates are unlikely to benefit low-income ratepayers" (Workshop 3 consideration memo, Exhibit B-1, Appendix C-3A, page 145 of 184); and**

2. **Only one Canadian jurisdiction, Ontario, has adopted default TOU rates for residential and commercial customers. As noted at Exhibit B-1, page 2-12, footnote 52, Ontario Auditor General in its 2014 annual report concluded that Ontario's mandatory residential and commercial TOU rates:**

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[1] **Then Deputy Minister to the Premier, Deputy Minister of Finance, Assistant Deputy Minister of Advanced Education; https://news.gov.bc.ca/files/Newsroom/downloads/bchydroreview.pdf.**

"[H]ad a modest impact on residential ratepayers, reducing their peak demand by only about 3 per cent, but a limited or unclear effect on small businesses, and none at all on energy conservation".[2]

The Ontario Auditor General report discussed the lack of a significant enough difference between on-peak and off-peak rates to encourage a change in consumption patterns. In Workshops 3 (voluntary Residential TOU rate option) and 8a/8b (voluntary General Service TOU rate option), BC Hydro noted that a ratio of three to four of on-peak to off-peak pricing is required to change consumption, and that Mid C HLH/LLH ratios have averaged 1.45 over the last five years and will average 1.30 for the next year; refer to Exhibit B-1, page 7-21, lines 8 to 20.

[2] **http://www.auditor.on.ca/en/reports_en/en14/311en14.pdf; refer to section 3.11, page 368.**

4.0 Reference: Exhibit B-1, Application, 2.2.2 Government Policy, page 2-8, ll 22-23

BC Hydro states that it is government policy that there will be no mandatory Time of Use (TOU) pricing for residential and commercial customers.

1.4.2 Has BC Hydro analyzed what impacts TOU rates might have on peak demand and the integration of intermittent renewable supply?

1.4.2.1 If so, please provide that analysis.
1.4.2.2 If not, please explain why has BC Hydro failed to complete such an analysis?

RESPONSE:

No Ability to Integrate Intermittent Clean or Renewable Resources

TOU rates, whether mandatory or voluntary, cannot integrate intermittent (non-firm) clean or renewable resources because TOU rates are not dispatchable and do not provide firm energy. This was assessed as part of the Site C Joint Review Panel (JRP) hearings. A copy of BC Hydro's January 23, 2014 presentation to the JRP on this topic is found at http://www.ceaa.gc.ca/050/documents/p63919/98146E.pdf; refer to slide 17.

Delivery of Dependable Capacity Uncertain

Given that B.C. Government policy since 2011 (refer to BC Hydro's response to COPE IR 1.4.1) is that mandatory TOU rates for Residential and/or General Service customers is not an option for BC Hydro, for purposes of the 2015 RDA BC Hydro confined its assessment to the potential for voluntary Residential and/or General Service TOU rates to shave peak demand.

BC Hydro concludes that voluntary TOU rates for Residential and/or General Service customers is not a long-term planning resource that BC Hydro could rely on for purposes of deferring capacity generation resources. This assessment was shared with COPE 378 and other 2015 RDA stakeholders through the following consideration memos, which discuss BC Hydro's analysis on this topic:

- **Section 4.2.2 of the Workshop 3 consideration memo, copy at Exhibit B-1, Appendix C-3A, pages 118 to 120 of 184;**
- **Section 6.1.2 of the Workshop 8a/8b consideration memo, copy at Exhibit B-1, Appendix C-4A, pages 209 to 212 of 813; and**
- **Section 8.2 of the Workshop 11a/11b consideration memo, copy at Exhibit B-1, Appendix C-4B, pages 216 to 218 of 382.**

Refer also to section 2.1.2 of the Workshop 5 consideration memo (Exhibit B-1, Appendix C-5A, pages 105 to 107 of 292 for a discussion of the lack of on-peak to off-peak price differential as one of the reasons why no Transmission Service customer has sought service under RS 1825, BC Hydro's voluntary Transmission Service TOU rate, in place since April 1, 2006.

Module 2

While no stakeholder supported BC Hydro pursuing Residential or General Service TOU rate options, BC Hydro will revisit these options in the context of RDA Module 2's exploration of Residential and General Service rate options. BC Hydro will also explore a rate for EV at home charging (Exhibit B-1, page 1-22, line 26). BC Hydro notes that some U.S. jurisdictions have adopted TOU rate structures for EVs.[1]

[1] See, for example, http://www.c2es.org/initiatives/pev/maps/pev-electricity-pricing-by-tou.

4.0 Reference: Exhibit B-1, Application, 2.2.2 Government Policy, page 2-8, ll 22-23

BC Hydro states that it is government policy that there will be no mandatory Time of Use (TOU) pricing for residential and commercial customers.

1.4.3 Has BC Hydro analyzed what other possible impacts TOU rates might have on its operations?

1.4.3.1 If so, please provide that analysis.
1.4.3.2 If not, please explain why BC Hydro has failed to complete such an analysis.

RESPONSE:

Please refer to BC Hydro's response to COPE IR 1.4.2.

4.0 Reference: Exhibit B-1, Application, 2.2.2 Government Policy, page 2-8, ll 22-23

BC Hydro states that it is government policy that there will be no mandatory Time of Use (TOU) pricing for residential and commercial customers.

1.4.4 Has government provided to BC Hydro any analysis of TOU rates?

1.4.4.1 If so, please provide.
1.4.4.2 If not, please explain BC Hydro's understanding of what government used to inform its position prohibiting TOU rates.

RESPONSE:

BC Hydro respectfully declines to respond to these IRs on the basis that the requested information, concerning what analysis informed the B.C. Government's mandatory TOU rates for Residential and/or General Service customers policy in 2011, is not relevant to and cannot assist the Commission with its adjudication of 2015 RDA Module 1 or the orders sought with respect to it.

BC Hydro set out the B.C. Government's policy concerning mandatory default TOU rates for Residential and/or General Service customers at Workshop 1 in May 2014, and summarized the policy at section 2.2.2.2 of Exhibit B-1. In BC Hydro's view there is sufficient evidence on the record for the Commission to consider the issue, including the fact that no stakeholder advocated for mandatory default TOU rates for Residential and/or General Service customers. Please refer to BC Hydro's response to COPE 378 IR 1.4.1.

5.0 Reference: Exhibit B-1, Application, 2.3.2.1 Smart Meters, pages 2-44 to 2-46

BC Hydro states that the installation of Smart Meters is 99% complete and that these new assets have helped the utility to better understand load characteristics, enabling it to develop more accurate cost allocations.

"The additional data from smart metering has increased the accuracy of BC Hydro's load profile information which is a key input into cost allocation with the F2016 COS study. With the capability to create almost on-demand detailed customer load profiles, COS analysis, rate design and peak load forecasting can be improved." (page 2-45)

1.5.1 Has BC Hydro studied what improvements in rate design Smart Meters may enable?

1.5.1.1 If so, please provide those relevant studies, documents, or summaries.

1.5.1.2 If not, why has BC Hydro failed to study this?

RESPONSE:

As described in in section 3.5.4 of Exhibit B-1, SMI has improved BC Hydro's load research data which is used in the F2016 COS study and informs the determination of energy and demand charges. The improved load research data was used to inform the F2016 Draft COS Model found in Appendix C-2C of Exhibit B-1 as well as the Workshop 2 discussion guide found at Exhibit B-1, Appendix C-2A.

Generally speaking SMI can enable TOU-like rates:

- **As noted in BC Hydro's COPE 378 IR 1.4.1 BC Hydro is not considering mandatory default TOU rates for either Residential or General Service customers. The studies, documents, and / or summaries relied on are referenced in that response;**

- **While no 2015 RDA stakeholder favored BC Hydro pursing voluntary TOU rates for either Residential or General Service customers, BC Hydro will again explore these potential rate options as part of RDA Module 2. The studies, documents, and/or summaries relied on and are referenced in BC Hydro's response to COPE 378 IR 1.4.2; and**

- **BC Hydro will be exploring a rate for EV at home-charging as part of RDA Module 2. To date, BC Hydro's jurisdictional review of such a rate shows that often this is in the form of a TOU rate. Please refer to BC Hydro's response to COPE 378 IR 1.4.2.**

5.0 Reference: Exhibit B-1, Application, 2.3.2.1 Smart Meters, pages 2-44 to 2-46

BC Hydro states that the installation of Smart Meters is 99% complete and that these new assets have helped the utility to better understand load characteristics, enabling it to develop more accurate cost allocations.

"The additional data from smart metering has increased the accuracy of BC Hydro's load profile information which is a key input into cost allocation with the F2016 COS study. With the capability to create almost on-demand detailed customer load profiles, COS analysis, rate design and peak load forecasting can be improved." (page 2-45)

1.5.2 Has BC Hydro studied the opportunities to use Smart Meters to implement rates and controls that will enable customers to utilize price or system sensitive Smart Energy Management Technology?

1.5.2.1 If yes, please provide the relevant studies, documents, or summaries.

1.5.2.1.1 If yes, please indicate how these opportunities have influenced the development of the rate and other proposals in this RDA.

1.5.2.1.2 Please also indicate what opportunities identified BC Hydro has declined to pursue and apply in this RDA and explain why the utility has done so.

1.5.2.2 If no, why has BC Hydro failed to study this?

RESPONSE:

'Smart Energy Management Technology' enables customers to manage their electricity use through technologies such as programmable thermostats and 'smart' household appliances.

During the 2015 RDA stakeholder engagement process, no stakeholder raised the concept of rate design(s) to take advantage of Smart Energy Management Technology. It is not clear to BC Hydro what additional Residential rate designs would enable customers to take advantage of Smart Energy Management Technology.

BC Hydro foresees the following processes as enabling customers to take advantage of Smart Energy Management Technology:

- **Outage and restoration notifications – pinpoint outages near real time and reduce the time it takes to restore services;**

- **Consumer alerts – Automate customer alerts, online and through smart devices, informing Residential customers whenever their energy use is going to exceed the RIB rate Step 2 threshold. BC Hydro has taken a first step towards automated customer alerts; currently customers can subscribe to a Step 2 notification in MyHydro.**

As described in section 3.5.4 of Exhibit B-1, the introduction of SMI has significantly changed quality of its load research data, including more granular data, greater sample sizes and more accurate data.

NTD: **[Start typing Notes to Draft here]**
PRIVILEGED AND CONFIDENTIAL DRAFT This document contains confidential, internal policy recommendations and was prepared in consultation with legal counsel for this proceeding.

6.0 Reference: Exhibit B-1, Application, 2.3.2.3 Capacity Long-Run Marginal Cost, page 2-55, ll
ll 11-18

"Several Workshop 3 participants advanced two grounds for including a generation capacity value in the energy LRMC for purposes of the RIB Step 2 rate: (1) the RIB rate contains no demand charge; and (2) while the RIB is an energy conservation rate, it delivers anticipated capacity savings. In section 4.1.2 of the Workshop 3 consideration memo (copy at Appendix C-3A), BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction."

1.6.1 Please confirm that for the foreseeable future BC Hydro is more likely to be capacity constrained as opposed to energy constrained.

1.6.1.1 If this is not the case, please explain the basis upon which BC Hydro has determined it is more likely to be energy constrained than capacity constrained in the near future. If this is based on studies or data not already on the record, please file those materials.

RESPONSE:

Confirmed. As set out in the 2013 IRP, BC Hydro anticipates that in the future it will need to acquire additional capacity resources over and above the resources that it acquires for both energy and capacity benefits.

6.0 Reference: Exhibit B-1, Application, 2.3.2.3 Capacity Long-Run Marginal Cost, page 2-55, ll
ll 11-18

"Several Workshop 3 participants advanced two grounds for including a generation capacity value in the energy LRMC for purposes of the RIB Step 2 rate: (1) the RIB rate contains no demand charge; and (2) while the RIB is an energy conservation rate, it delivers anticipated capacity savings. In section 4.1.2 of the Workshop 3 consideration memo (copy at Appendix C-3A), BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction."

1.6.2 Does BC Hydro agree that reductions in peak capacity can have significant trade and other system benefits?

1.6.2.1 If so, please describe those benefits
1.6.2.2 If not, please explain why BC Hydro does not see any such benefits arising out of a reduction in peak capacity.

RESPONSE:

Reduction in peak demand resulting from the RIB rate is beneficial to the BC Hydro system by avoiding new generation capacity, transmission and distribution resources. However, as noted in BC Hydro's response to BCOAPO IR 1.22.3, the transmission and distribution benefits are relatively small. Furthermore, given the avoided generation capacity resource would have come with trade and other system benefits, adding these benefits to the avoided generation capacity benefit would be double counting.

6.0 Reference: Exhibit B-1, Application, 2.3.2.3 Capacity Long-Run Marginal Cost, page 2-55, ll
ll 11-18

"Several Workshop 3 participants advanced two grounds for including a generation capacity value in the energy LRMC for purposes of the RIB Step 2 rate: (1) the RIB rate contains no demand charge; and (2) while the RIB is an energy conservation rate, it delivers anticipated capacity savings. In section 4.1.2 of the Workshop 3 consideration memo (copy at Appendix C-3A), BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction."

1.6.3 Since BC Hydro does not believe that it is appropriate to add a capacity value to the Step 2 RIB rate, how does the utility propose to provide a signal, price or otherwise, to customers of their marginal capacity costs or values in order to encourage efficiencies and reductions in peak requirements?

1.6.3.1 Please file the documents, studies, or summaries BC Hydro used to formulate its position on whether it was appropriate to provide a signal and what form that signal would or could take.

RESPONSE:

For the reasons set out in BC Hydro's response to BCUC IR 1.13.1, BC Hydro is of the view that there is little justification for including a generation capacity value in the energy LRMC for the purpose of setting the RIB Step 2 rate. BC Hydro implemented the RIB rate with the intention of encouraging energy conservation. Peak demand reduction is an expected by-product of the rate, but it is not a goal of the rate. The documents, studies and summaries BC Hydro used to formulate its position on this topic are included in Exhibit B-1 as summarized in section 2.3.2.3 of Exhibit B-1, in particular on page 2-55.

BC Hydro is not otherwise considering signals, price or otherwise, to Residential customers of their marginal capacity costs to encourage efficiencies and reductions in peak requirements as part of 2015 RDA Module 1:

- **BC Hydro is not pursuing a mandatory default Residential TOU rate for reasons summarized in BC Hydro's response to COPE 378 IRs 1.4.1 and 1.4.2. BC Hydro's response to COPE 378 IR 1.4.1 references the documents, studies and summaries BC Hydro used to formulate its position on a mandatory default TOU rate;**

- **While no 2015 RDA stakeholder supported BC Hydro pursuing a voluntary Residential TOU rate, including COPE 378, BC Hydro will revisit such a rate as part of Module 2; and**

- **No 2015 stakeholder supported including a demand charge as part of the default Residential rate. Generally speaking, low use customers, including many low income customers, would likely face bill increases if the default Residential rate contained a demand charge. None of the Canadian jurisdictions BC Hydro surveyed have demand charges in place for residential customers; refer to the Workshop 9a presentation slide deck, Exhibit B-1, Appendix C-3B, pages 25 to 31 of 609.**

7.0 Reference: Exhibit B-1, Application, 5.2.2.2 Residential Class Characteristics, page 5-10, ll 5 5-10

"The consumption per account is generally highest for SFDs with a median consumption of about 9,800 kWh/year and a median F2016 annual electricity bill of about $900. In comparison, apartments and condominiums generally have the lowest consumption per account with a median consumption of about 3,700 kWh/year and a median F2016 annual bill of about $360."

1.7.1 Does BC Hydro consider it consistent with the Bonbright fairness criterion to have the same Step 1 / Step 2 breakpoint set for SFDs and apartments/condos given the fact that they each have markedly different median electricity consumptions?

1.7.1.1 If yes, please explain how this is consistent with the fairness criterion.

1.7.2.1 If no, please explain why BC Hydro has not adjusted its Step 1 / Step 2 breakpoints for these two dwelling types in order to ensure the RIB is more fair?

RESPONSE:

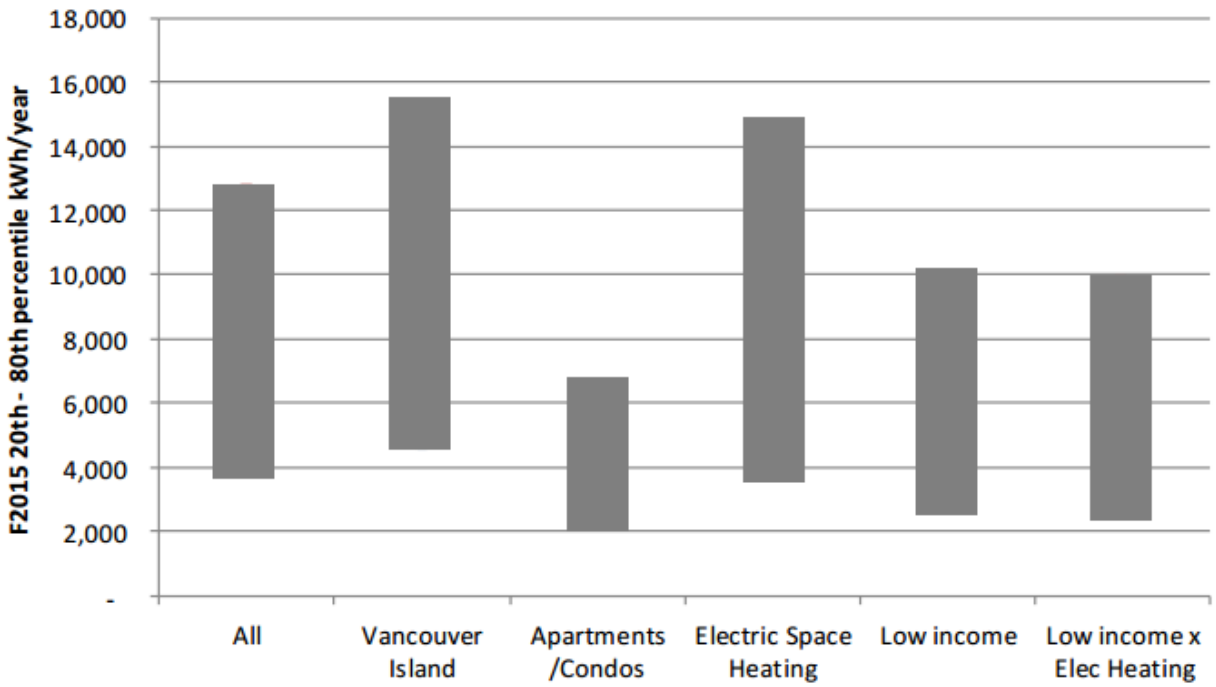
The use of two separate RIB rate thresholds for SFDs and apartments/condos implies that the Residential rate class should be segmented according to dwelling type. BC Hydro rejected this for the reasons listed in section 4.2.1 of Exhibit B-1 because differences in the cost to serve SFD and apartment/condos, as measured on a cents/kWh basis, are driven less by total consumption and more by factors such as the time of their energy consumption and the coincidence of their load with the system peak. This addresses the Bonbright fairness criterion.

In addition, setting two separate rate thresholds for SFDs and apartments/condos leaves unanswered how to address dwellings with consumption between these two, such as townhouses, row houses, and duplexes. Accordingly, in BC Hydro's view two separate rate thresholds for SFDs and apartments/condos will be arbitrary, and thus does not align with the Bonbright customer understanding criterion.

8.0 Reference: Exhibit B-1, Application, 5.2.2.2 Residential Class Characteristics, page 5-12, line 8 and page 5-16, Figure 5-12

"The median consumption of low income accounts is about 5,297 kWh/year…"

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.8.1 Please confirm that the median electricity consumption for low income customers is 43% higher than the median consumption for apartments and condos.

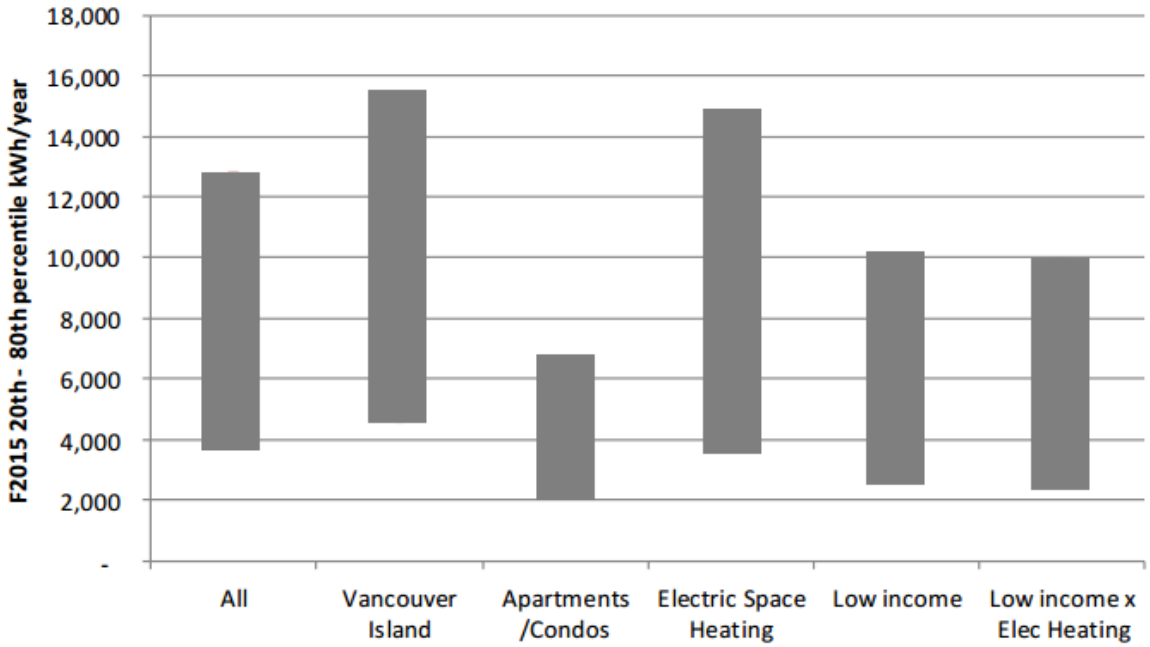
RESPONSE:

Confirmed.

8.0 Reference: Exhibit B-1, Application, 5.2.2.2 Residential Class Characteristics, page 5-12, line 8 and page 5-16, Figure 5-12

"The median consumption of low income accounts is about 5,297 kWh/year…"

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.8.2 Please confirm that the consumption range for low income customers is much broader than the range for apartments / condos.

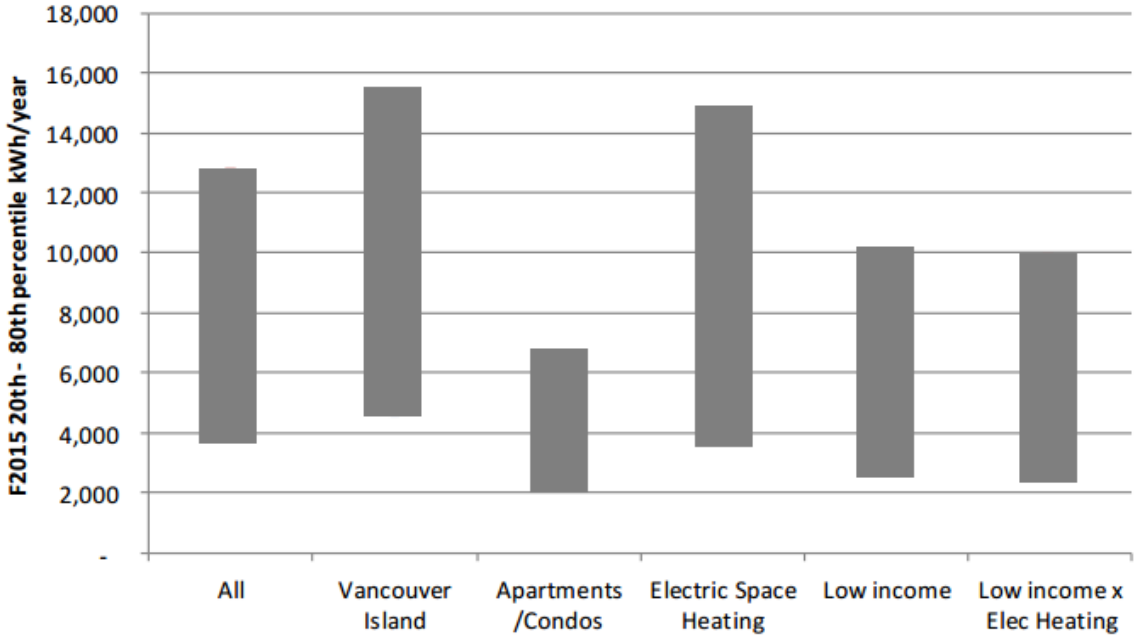
RESPONSE:

Confirmed.

8.0 Reference: Exhibit B-1, Application, 5.2.2.2 Residential Class Characteristics, page 5-12, line 8 and page 5-16, Figure 5-12

"The median consumption of low income accounts is about 5,297 kWh/year…"

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.8.3 Please confirm that this higher median consumption is due to the significant number of low income customers who live in single family dwellings (SFDs).

RESPONSE:

Not confirmed. Dwelling type is one of the factors that can lead to higher consumption, and typically customers living in SFDs consume more than customers living in apartments/condos.

As shown in Workshop 3 on Exhibit B-1, Appendix C-3A, page 26 of 184, the low-income customer segment households have a much larger share of apartments (42 per cent) than the full population (27 per cent), and a much lower

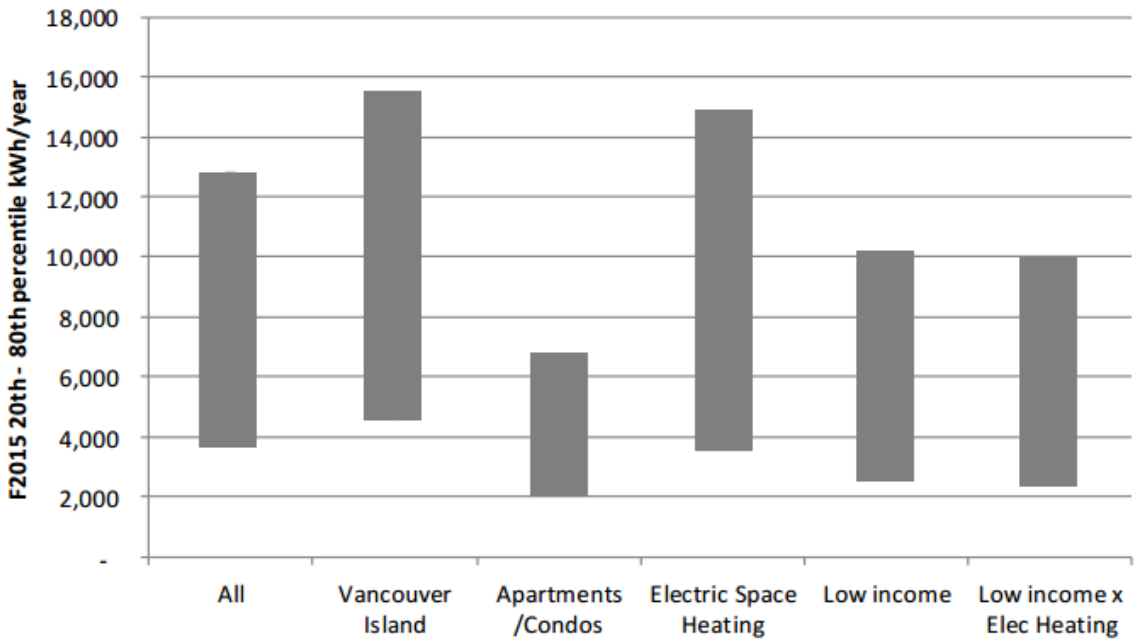
share of SFDs (36 per cent) than the full population (56 per cent). As a result, per Figure 5-12 of Exhibit B-1, the consumption distribution of the typical low income customers is somewhat lower than that of the full population.

Exhibit B-1, Appendix C-3A, page 26 of 184 also shows that the average consumption of low income households in apartments is lower than apartment households for the full population.

8.0 Reference: Exhibit B-1, Application, 5.2.2.2 Residential Class Characteristics, page 5-12, line 8 and page 5-16, Figure 5-12

"The median consumption of low income accounts is about 5,297 kWh/year…"

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.8.4 Table 5-15 on page 5-68 of the Application shows the percentage of each dwelling type held by low income customers. Please provide

i) the number of low income customers by dwelling type; and
ii) the number of customers defined as low income for the purposes of DSM programming (1.3 times the LICO rate) by dwelling type.

RESPONSE:

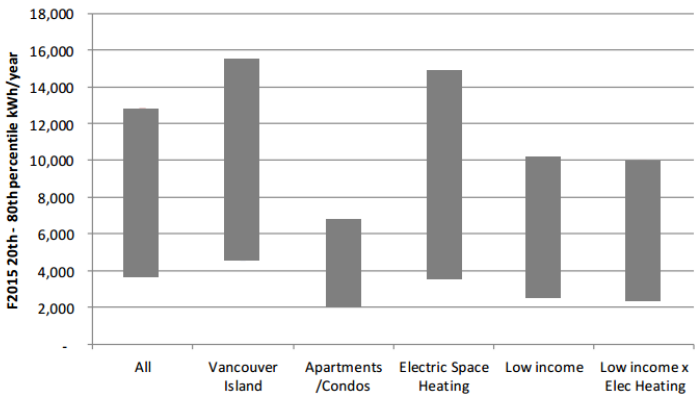
The estimates of number of low income customers based on the same vintage of modelling assumptions for Exhibit B-1, Figure 5-12 are as follows:

	LICO(i)	1.3x LICO(ii)
Single detached house	**55,248**	**162,568**
Duplex/Row/Town	**20,994**	**55,211**
Apartment/condominium	**76,381**	**149,748**
Mobile/other	**8,664**	**31,931**
Total	**161,287**	**399,458**

8.0 Reference: Exhibit B-1, Application, 5.2.2.2 Residential Class Characteristics, page 5-12, line 8 and page 5-16, Figure 5-12

"The median consumption of low income accounts is about 5,297 kWh/year…"

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.8.5 BC Hydro has stated and the BCUC has confirmed in previous decisions that the RIB rate structure benefits the majority of low income customers. Please confirm that the extent of that benefit varies considerably between low income customers living in SFDs and those living in apartments/condos.

RESPONSE:

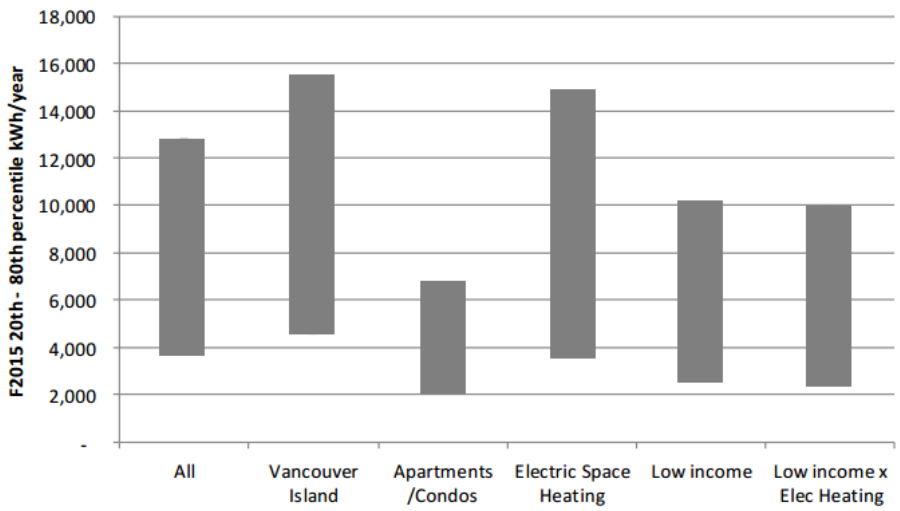
All customers under the existing RIB rate have the benefit of the lower Step 1 rate up to 1,350 kWh on a bi-monthly basis, at any income level, for customers residing in any type of dwelling.

In the context of the 2008 RIB Application, the analysis showed that moving from the previous flat rate to the RIB rate would reduce the bill impact for customers with a majority of consumption in Step 1, which includes many low income customers. This is due to a reduction of the Step 1 rate from the prevailing flat rate as of October 2008 to maintain revenue neutrality.

8.0 Reference: Exhibit B-1, Application, 5.2.2.2 Residential Class Characteristics, page 5-12, line 8 and page 5-16, Figure 5-12

"The median consumption of low income accounts is about 5,297 kWh/year…"

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



1.8.6 Please confirm that for low income customers in the higher end of the household electricity consumption range, the RIB rate does nothing to ease the burden of those energy costs.

1.8.6.1 If not, please explain how it eases this burden.

RESPONSE:

All customers have the benefit of the lower Step 1 price up to 1,350 kWh on a bi-monthly basis. The two-step RIB rate design does not have a mechanism to provide rate adjustments based on specific income levels of individual customers.

9.0 Reference: Exhibit B-1, Application, 5.2.3 2013 Residential Inclining Block Rate Evaluation Report, page 5-17, ll 11-14

- The class average elasticity due to RRA rate increases under a flat rate was not able to be estimated using empirical data. The evaluation used the assumption of -0.05 as the class average price elasticity to determine the natural conservation baseline.

1.9.1 Is there an empirical basis for the assumption that in the absence of a RIB rate, the elasticity of demand for BC Hydro customers since the RIB came into effect would have been -0.05?

RESPONSE:

BC Hydro's work to produce an empirically based estimate of elasticity under a flat rate is summarized below.

As described in the 2013 RIB Evaluation Report (Exhibit B-1, Appendix C-3B, page 125 of 609), BC Hydro attempted to estimate the class average price elasticity under a flat rate using a Seemingly Unrelated Regression model. This model yielded estimates that closely matched the original RIB Step 1 rate price elasticity assumption of -0.05, but were not statistically significant.

Also as described in the 2013 RIB Evaluation Report (Exhibit B-1, Appendix C-3B, page 122 of 609), BC Hydro attempted to estimate the class average price elasticity under a flat rate as the weighted average of RIB Step 1 and Step 2 elasticity. However, the Step 1 price elasticity was not statistically significant.

In 2014 BC Hydro attempted to estimate the price elasticity of electricity consumption by residential customers in the New Westminster, who pay for their electricity under a flat rate. The objective was to potentially use this estimate as a proxy for the flat rate price elasticity of BC Hydro customers who have characteristics similar to those of New Westminster residential customers. However, the resulting price elasticity for New Westminster customers was not statistically significant. These efforts are documented in a BC Hydro letter to the Commission. Please refer to Exhibit B-1, Appendix C-3D, Attachment 1 to the summary of the June 29, 2015 meeting with COPE 378, pages 60 to 65 of 67.

In the absence of a precise estimate of the class average elasticity under a flat rate, BC Hydro has relied on the assumption of -0.05. This price elasticity was recommended to BC Hydro by Dr. Ren Orans on the basis of his literature review of 105 peer-reviewed papers on residential electricity demand, as described in

both the 2008 LTAP and the 2008 RIB Application;[1] Relevant extracts of the 2008 LTAP Direct Testimony of Dr. Orans are found at Attachment 1 to this response.

The following evidence presented in the 2013 RIB Evaluation Report supports the continued use of this assumption:

- **The Step 2 price elasticity recommended to BC Hydro by Dr. Orans has been validated. Please refer to Exhibit B-1, Appendix C-3B, page 111 of 609. This increases BC Hydro's confidence in the continued use of Dr. Orans' recommended elasticity under a flat rate;**

- **Empirical work presented in the 2013 RIB Evaluation demonstrates that large electricity consumers have higher price elasticity than do smaller consumers (Exhibit B-1, Appendix C-3B, pages 131 to 132 of 609). To the extent this higher elasticity is related to higher consumption under the Step 2 price, it follows that class average price elasticity under a flat rate would be lower than the empirically verified estimate of Step 2 elasticity of -0.08 to -0.13.**

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[1] BC Hydro relied upon the conclusions of Dr. Orans in BC Hydro's 2008 LTAP, Appendix E, Elasticity Report (Testimony of Dr. Ren Orans), copy available at http://www.bcuc.com/Documents/Proceedings/2008/DOC_18927_B-1_BCH%202008%20Long-Term%20Acquisition%20Plan.pdf.

3. Price elasticity assumption

Q18. PLEASE DESCRIBE THE BASIS OF YOUR RECOMMEDNED ELASTICITY VALUE OF -0.01.

A18. My recommended value of -0.1 is based on:

- A review of published studies of measured price response results in other jurisdictions with relatively low rates and a winter peaking system, similar to BC Hydro's jurisdiction; and
- The elasticity values used in the Integrated Resource Plans (IRPs) of two electric utilities in the U.S. Pacific Northwest.

Q19. PLEASE DESCRIBE YOUR FINDING FROM YOUR REVIEW OF RESIDENTIAL DEMAND STUDIES.

A19. My review of over 100 studies identifies a wide range of residential price elasticity estimates. A case in point are the residential estimates reported in a 2004 meta-analysis, summarizing (a) 123 short-run estimates that range from -0.004 to -2.01, with an average of -0.35; and (b) 125 long-run estimates that range from -0.04 to -2.25 with an average of -0.85.[2] The variance in these estimates is due to differences in data samples (e.g., time-series versus cross-sectional data, regional versus customer level), estimation methods (e.g., simple versus complicated), and model specifications (e.g., linear versus log-linear, static versus dynamic). Hence, I find that it is more appropriate to use elasticity estimates from

[2] Espey, J. A. and M. Espey (2004) "Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities." *Journal of Agricultural and Applied Economics* 36: 65-81.

suitably chosen studies that can better match BC Hydro's characteristics of being winter peaking and having comparatively low and stable rates.

Q20. PLEASE DESCRIBE THE RELEVANT STUDIES SUPPORTING THE -0.1 ELASTICITY RECOMMENDATION FOR THE RESIDENTIAL SECTOR.

A20. Table 2 below describes four studies that reflect the results from jurisdictions comparable to British Columbia and cover a price elasticity range from a low of 0.0 in one case to a high of -0.28. These studies bound my recommended -0.1 elasticity and provide evidence that it is reasonable to expect relatively low-cost jurisdictions in the U.S. Pacific Northwest to have elasticities below -0.2.

The first study is a 2005 analysis by Rand Corporation of regional differences in demand for energy. It is chosen because it contains elasticity estimates for Washington, a winter-peaking state next to British Columbia with relatively low rates. This analysis indicates a short-run price elasticity estimate of -0.079 and a long-run estimate of -0.161.

The second study is a 1994 paper reporting the results of a Wisconsin rate experiment designed to test customer price response to inclining block rates. It is chosen because (a) Wisconsin had high winter demand and relatively low rates during the study period, and (b) the rate experiment's focus was customer response to an inclining block tariff. This paper reports low price elasticity estimates: -0.02 for summer and -0.04 for winter.

The third study is a 1994 paper that quantifies the price elasticity of sales by municipal utilities in Ontario. It is chosen because Ontario had low rates in the late 1980s and was a winter peaking jurisdiction.[3] This paper shows low price elasticity estimates between 0.0 to -0.07.

The last study is a 1984 paper reporting the price responsiveness of residential customers in Washington, Oregon, Idaho and Montana. These states had low rates and were winter-peaking during the study period. This paper reports short-run elasticity estimates between -0.11 to -0.28.

Taken together, these four studies suggest that a price elasticity estimate of -0.1 is a conservative but plausible assumption used to quantify the residential consumption response to a new inclining block tariff that embodies an average rate change.

[3] Ontario now has relatively high rates and is becoming a summer peaking utility due to rising cooling loads.

Table 2: Residential demand studies used to support an elasticity value of -0.1

Study	Data sample	Jurisdiction	Short-run elasticity	Long-run elasticity
Bernstein and Griffin (2005)[4]	Annual consumption by state for 1977-2004	Washington	-0.079	-0.161
Herriges and King (1994)[5]	Monthly billing data for a rate experiment for 1500 customers in 1984-85	Wisconsin	-0.02 (Summer) -0.04 (Winter)	Not available
Hsiao and Mountain (1994)[6]	Monthly sales by municipal utility in 1989	Ontario	-0.0 to -0.07	Not available
Henson (1984)[7]	Monthly data for 1077 households observed during 1977-78	Bonneville Power Administration	-0.11 to -0.28	Not Available

Q21. PLEASE DESCRIBE YOUR FINDINGS FROM YOUR REVIEW OF NON-RESIDENTIAL DEMAND STUDIES.

A21. My review of 60 non-residential studies also identifies widely dispersed non-residential price elasticity estimates. A 1984 Rand Report, for example, summarizes 120 price elasticity estimates that are as low as -0.04 and as high as -

[4] Bernstein M. and J. Griffin (2005) "Regional Differences in the Price-Elasticity of Demand for Energy," (http://RAND.org/pubs/technical_reports/2005/RAND_TR292.pdf, pp.82-84.

[5] Herriges, J. and K. King (1994) "Residential Demand for Electricity Under Block Rate Structures: Evidence from a Controlled Experiment," *Journal of Business and Economic Statistics*, 12(4): 419-430, Table 4.

[6] Hsiao C. and D.C. Mountain (1994) "A Framework for Regional Modeling and Impact Analysis: An Analysis for the Demand for Electricity by Large Municipalities in Ontario, Canada," *Journal of Regional Science*, 34(3): 361-385, Table 3.

[7] Henson, S. E., (1984) "Electricity Demand Estimates under Increasing-Block Rates," *Southern Economic Journal* 51(1): 147-156, Table 11.

4.5.[8] A more recent 2004 price elasticity survey summarizes 44 estimates and finds a short-run price elasticity range of +0.11 to -0.33 and a long-run price elasticity range of 0.0 to -1.88.[9] Similar to the residential case, the variance in non-residential estimates is attributable to differences in data samples, estimation methods, and model specifications. Hence, rather than use an average from a broad range, I find that it is more appropriate to use elasticity estimates from suitably chosen studies that better match British Columbia's characteristics of being winter peaking and having comparatively low and stable rates.

Q22. PLEASE DESCRIBE THE RELEVANT STUDIES SUPPORTING THE -0.1 ELASTICITY RECOMMENDATION FOR THE NON-RESIDENTIAL SECTOR.

A22. Listed in Table 3, the first three studies report elasticity estimates by time of use TOU for comparable jurisdictions with relatively low rates and cold climates.[10] They are chosen because I cannot find suitable studies with elasticity estimates for non-TOU pricing that entails a flat or inclining block rate design. That said, the non-TOU average price elasticity estimate is the volume-weighted average of each set of TOU elasticity estimates. Thus, the TOU price elasticities in Table 3 bound their associated non-TOU average price elasticity.

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[8] Acton, J.P. and E.R. Park (1984) *Projecting Response to Time-of-Day Electricity Rates*. RAND Report: N-2041-MD. Appendix B of this report shows a range of -0.04 to -4.5.

[9] Dahl, C. and C. Roman (2004) "Energy Demand Elasticities – Fact or Fiction: A Survey," Working Paper, Colorado School of Mines, Table 5. Based on 11 estimates, this survey reports a range of +0.11 to -0.33 for the short-run price elasticity, yielding an average of -0.14. Based on 44 estimates, the same survey finds a range of 0.0 to -1.88 for the long-run price elasticity, resulting in an average of -0.56.

[10] Even though each sample may contain relatively few customers, the sample size for estimation is large because of the use of daily observations, thus mitigating criticism that the empirical findings in these studies may be unreliable.

The first study is a recently completed 2007 Fraser Institute Report for Ontario's industrial customers. It shows elasticity values of between -0.1 to -0.14 in response to TOU pricing. The second study is my firm's 1997 analysis of the nine large industrial customers on Rate Schedule 1821 who participated in BC Hydro's Real-Time Pricing program. The analysis indicates very limited price responsiveness, with elasticity values between -0.04 and -0.08. The third study is a 1997 paper that estimates the price responsiveness of small commercial firms in Ontario, finding elasticity estimates between -0.04 to -0.09.

In addition to the three studies described above, I have also consulted a 1987 Rand study of large customers served by 10 U.S. utilities in the late 1970s. The study's extensive data file helps determine if significant price responsiveness exists among large customers across the U.S. The elasticity estimates from this 1987 study are small, ranging from 0.0 to -0.02.

Taken together, the four studies show short-run elasticity values between 0.0 and -0.142, confirming that -0.1 is also a conservative but plausible price elasticity estimate for use in sales forecasting in British Columbia for commercial customers as well.

Table 3: Non-residential demand studies used to support an elasticity value of -0.1

Study	Data sample	Jurisdiction	Short-run elasticity	Long-run elasticity
Angevine and Hrytzak-Lieffers (2007))[11]	Hourly load data for 47 companies from May 2002 to August 2006.	Ontario	-0.102 to -0.142 (on-peak hours)	Not available
Woo (1997)[12]	Daily consumption data by TOU for 9 customers during 04/01/94 to 01/31/97	B.C.	-0.041 (Heavy load hours); -0.083 (Light load hours)	Not available
Ham et al (1997)[13]	15-minute load data for 120 small customers in a TOU experiment from 1985 – 1987.	Ontario	-0.04 to -0.09	Not Available
Acton and Park (1987)[14]	Monthly data by time-of-use for large customers served by 10 utilities in the US during 1977-1980	California, Wisconsin, Illinois and New York	-0.00 to -0.025	Not available

Q23. PLEASE DESCRIBE YOUR REVIEW OF U.S. ELECTRIC UTILITY IRPS.

[11] Angevine, G. and D. Hrytzak-Lieffers (2007) *Ontario Industrial Electricity Demand Responsiveness to Price*, Fraser Institute, p.10.
[12] E3 (1997) Consumption response to optional real time pricing, 04/07/97 memo to Peter Chow, BC Hydro.
[13] Ham, J., *et al*. (1997) "Time-of-Use Prices and Electricity Demand: Allowing for Selection Bias in Experimental Data," *RAND Journal of Economics* 28(0): 113-141, Table 5.
[14] Acton, J.P and R.E. Park (1987) *Response to Time-of-Day Electricity Rates by Large Business Customers: Reconciling Conflicting Evidence*, Rand Report R-3477-NSF, Table 16.

A23. To gauge the reasonableness of my recommended elasticity value of -0.1, I also compare it to those used by Avista Corp. (Avista) and PacifiCorp in their IRPs. Table 4 shows that -0.1 is comparable to those used by Avista and PacifiCorp.

Table 4: Residential elasticity estimates used by Pacific Northwest utilities in their 2007 IRP

Utility	Short-run elasticity	Long-run elasticity
Avista[15]	-0.15 (Residential) -0.10 (Non-residential)	Not available
PacifiCorp [16]	-0.05 (Residential) -0.1 (Non-residential)	-0.09 (Residential)

Q24. BC HYDRO ASSUMES A LOWER ELASTICITY TO COMPUTE THE CONSERVATION EFFECT OF A RATE LEVEL CHANGE UNDER A FLAT RATE DESIGN THAN AN INCLINING BLOCK DESIGN. IS THIS ASSUMPTION REASONABLE?

A24. This assumption asserts that sales response to a change in price is smaller under a flat rate deign than an inclining block design. The assertion is reasonable under the following two conditions:

- Customers respond to marginal prices. That is, a customer with consumption below (above) the Step-1 threshold of a Two-Step inclining block tariff will

[15] Avista Utilities 2007 Electric Integrated Resource Plan, filed with the Idaho Public Utilities Commission, p.2-7, stating "We estimate customer class price elasticity in our computation of electricity and natural gas demand. Residential customer price elasticity is estimated at negative 0.15. Commercial customer price elasticity estimated at negative 0.10."

[16] PacifiCorp 2007 Integrated Resource Plan, Appendices, p.12, p.22. The residential elasticity estimates are found by estimating an econometric equation that explains per customer usage during 1982-2005 using real electricity price, real natural gas price, real household income, weather, and lagged usage. The -0.1 non-residential elasticity is based on the Department of Energy's 2006 Demand Response Report to the Congress.

face and respond to a marginal price equal to the relatively low Step-1 rate (high Step-2 rate).

- There is more marginally priced energy at the Step-2 rate than the Step-1 rate.

Under these two conditions, the conservation impact of an inclining block tariff designed to collect a given average rate increase is larger than the impact of a flat tariff that collects the same rate increase. This is because even though the Step-1 rate is not as high as the new flat rate, the Step-2 rate can exceed the new flat rate by a large amount. Since there is more energy marginally priced at the Step-2 rate, the incremental conservation (above the new flat rate's impact) can more than offset the decremental conservation (below the flat rate's impact). As a result, the conservation impact is smaller under the flat rate than the inclining block rate for a given rate level change.

Q25. IS BC HYDRO'S ELASTICITY ASSUMPTION OF -0.05 REASONABLE FOR COMPUTING THE CONSERVATION EFFECT OF A RATE LEVEL CHANGE UNDER A FLAT RATE DESIGN?

A25. This assumption is reasonable under the two conditions identified in A24. These two conditions are met in BC Hydro's case. Moreover, the -0.05 value is consistent with the low end of the range of elasticity estimates reported in Tables 2-4 above.

Q26. IS BC HYDRO'S ESTIMATION OF THE TOTAL CONSERVATION EFFECT OF A NEW INCLINING BLOCK RATE REASONABLE?

A26. Yes, as I have indicated in A17 above.

4. Conclusion

Q27. WHAT ARE YOUR KEY FINDINGS?

A27. They are as follows:

- BC Hydro should use a single short-run price elasticity to project rate-induced conservation, with separate accounting of the longer term impacts of changes in codes and standards and Power Smart programs.
- BC Hydro should adopt a conservative price elasticity estimate of -0.1 to estimate the combined impact of an average rate increase and a rate design change from a flat rate to an inclining block tariff.
- It is reasonable for BC Hydro to use -0.05 as the price elasticity estimate for decomposing the total conservation impact of an inclining block rate into rate level-induced and rate design-induced conservation, as is done in BC Hydro's 2007 Electric Load Forecast.

Q28. DOES THIS CONCLUDE YOUR TESTIMONY?

A28. Yes.

Ren Orans ren@ethree.com 415.391.5100

ENERGY & ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Managing Partner 1993 – Present

Dr. Orans founded this consulting firm in 1993. The firm has nationally recognized experts in the fields of transmission and distribution planning, economic and regulatory theory and finance. Dr. Orans heads the Litigation support and utility planning practices for E3.

Dr. Orans' work in utility planning is centered on the design and use of area and time-specific costs for both pricing and evaluation of grid infrastructure alternatives. The first successful application was conducted for Pacific Gas and Electric Company in their 1993 General Rate Case. Using costs developed by Dr. Orans, PG&E became the first electric utility to use area and time specific costing in its ratemaking process.

Dr. Orans also used the same data to develop a process called local integrated resource planning (LIRP) using detailed estimates of incremental costs for transmission and distribution planning areas. This work was formalized in his dissertation, *Area-Specific Cost of Electric Utilities: A Case Study of Transmission and Distribution Costs* and his work with the Electric Power Research Institute to document this new LIRP process. This seminal work led to applications in pricing, marketing and planning for Wisconsin Electric Company, Niagara Mohawk Power Company, Public Service of Indiana, Kansas City Power and Light, Central and Southwest Utilities, Central Power and Light, Philadelphia Electric Company, Tennessee Valley Authority and Ontario Hydro.

Dr. Orans expertise in utility planning is complimented by his working experience at Pacific Gas and Electric Company, where he was responsible for designing electric rates from 1982 to 1985. He has relied on this background along with his published papers to provide expert testimony on transmission pricing on behalf of BC Hydro (1996, 1997 and 2004), Ontario Power Generation (2000) and Hydro Quebec (2001, 2005). He has also worked extensively on the formulation of Regional Transmission Organizations (Grid West) in the U. S. Pacific Northwest. His current cases include the development of estimates the cost to comply with California's greenhouse gas compliance law (AB32) for the California PUC and the California Air Resource Board (CARB), and the independent evaluation of San Diego Gas and Electric's proposed Sunrise 500 KV transmission line on behalf of the California ISO in a need determination proceeding before the CPUC.

DEPARTMENT OF ENERGY Washington, DC
NATIONAL RENEWABLE ENERGY LABORATORY 1992 – 1993
ELECTRIC POWER RESEARCH INSTITUTE
Lead Consultant

Developed new models to evaluate small-scale generation and DSM placed optimally in utility transmission and distribution systems.

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Research and Development Department 1989 – 1991

Dr. Orans developed an economic evaluation method for distributed generation alternatives. The new approach shows that targeted, circuit-specific, localized generation packages or targeted DSM can in some cases be less costly than larger generation alternatives. He also developed the evaluation methodology that led to PG&E's installation of a 500KW photovoltaic (PV) facility at their Kerman substation. This is the only PV plant ever designed to defer the need for distribution capacity.

ELECTRIC POWER RESEARCH INSTITUTE Palo Alto, CA
1988 – 1992

Developed the first formal economic model capable of integrating DSM into a transmission and distribution plan; the case study plan was used by PG&E for a $16 million pilot project that was featured on national television.

DEPARTMENT OF ENERGY Washington, DC
1989 – 1990

Lead consultant on a cooperative research and development project with the People's Republic of China. The final product was a book on lessons learned from electric utility costing and planning in the United States.

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Corporate Planning Department 1989 – 1992

Lead consultant on a joint EPRI and PG&E research project to develop geographic differences in PG&E's cost-of-service for use in the evaluation of capital projects. Developed shared savings DSM incentive mechanisms for utilities in California.

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Rate Department Economist 1981 – 1985

As an economist at PG&E, he was responsible for the technical quality of testimony for all electric rate design filings. He was also responsible for research on customers' behavioral response to conservation and load management programs. The research led to the design and implementation of the first and largest residential time-of-use program in California and a variety of innovative pricing and DSM programs.

Education

STANFORD UNIVERSITY Palo Alto, CA
Ph.D. in Civil Engineering

STANFORD UNIVERSITY Palo Alto, CA
M.S. in Civil Engineering

UNIVERSITY OF CALIFORNIA Berkeley, CA
B.A. in Economics

Refereed Papers

Woo, C.K., E. Kollman, R. Orans, S. Price and B. Horii (2008) "Now that California Has AMI, What Can the State Do with It?" Energy Policy, 36, 1366-74.

Lusztig, C., P. Feldberg, R. Orans and A. Olson (2006) "A survey of transmission tariffs in North America," Energy-The International Journal, 31, 1017-1039.

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6. *Orans, R., C.K. Woo, R. Pupp and I. Horowitz (1994), "Demand Side Management and Electric Power Exchange," Resource and Energy Economics, 16, 243-254.*

7. *Pupp, R., C.K.Woo, R. Orans, B. Horii, and G. Heffner (1995), "Load Research and Integrated Local T&D Planning," Energy - The International Journal, 20:2, 89-94.*

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9. *Orans, R., C.K. Woo and B. Horii (1994), "Targeting Demand Side Management for Electricity Transmission and Distribution Benefits," Managerial and Decision Economics, 15, 169-175.*

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11. Orans, R., Seeto, D., and Fairchild, W., (1985), "The Evolution of TOU Rates," Pergamon Press.

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1. Orans, R. Olson, A., Integrated Resource Plan for Lower Valley Energy, December, 2004.

2. Orans, R., Woo C.K., and Olsen, Arne, Stepped Rates Report, prepared for BC Hydro and filed with the BCUC, May, 2003.

3. Orans, R., Woo, C.K, and B. Horii (1995), Impact of Market Structure and Pricing Options on Customers' Bills, Report submitted to B.C. Hydro.

4. Horii, B., Orans, R., Woo, C.K., (1994) Marginal Cost Disaggregation Study, Report submitted to PSI Energy.

5. Woo, C.K., L. Woo and R. Orans (1995), Rationing and Area-Specific Generation Costs, Report submitted to Pacific Gas and Electric Company.

6. Orans, R., C.K. Woo and C. Greenwell (1994), Designing Profitable Rate Options Using Area- and Time-Specific Costs, Report No. TR-104375, Electric Power Research Institute.

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1. *Orans, R. Evaluating Generating Resources based on a Equivalent Reliability Methodology, 2nd Annual Resource Planning Symposium, January, 2004, Vancouver, Canada.*

2. *Martin, J., Orans, R., Knapp, K., "DG Economics and Distribution Rate Design" (2000), Western Electric Power Institute, Distributed Generation and the Utility Distribution System Conference, March 22-23, Reno, NV.*

3. *Orans, R. (1997), "Getting the Transmission Prices Right," Facilitating Cross Border Trade, New Mexico.*

4. *Orans, R. (1997), "Deregulation on the Mainland, What is Happening and What is Not, PCEA Conference, Hawaii.*

5. *Swisher, J., Orans, R., (1995), "A New Utility DSM Strategy Using Intensive Campaigns Based on Area Specific Costs," ECEEE 1995 Summer Study.*

6. *Orans, R., Greenwell, C., (1995), "Designing Profitable Rate Options Using Area and Time-Specific Costs," Prepared for EPRI, Annual DSM Review, Dallas, Texas.*

7. *Orans, R, Integrated Local Area Planning, (1995), Prepared for NELPA and presented in Calgary.*

8. *Orans, R., Local Area Planning for Profit, "Annual Review of Distributed Resource Studies," Prepared for EPRI, Lake George, New York.*

9. *Orans, R., C.K. Woo, B. Horii and R. Pupp, (1994), "Estimation and Applications of Area- and Time-Specific Marginal Capacity Costs," Proceedings: 1994 Innovative Electricity Pricing, (February 9-11, Tampa, Florida) Electric Research Power Institute, Report TR-103629, 306-315.*

9.0 Reference: Exhibit B-1, Application, 5.2.3 2013 Residential Inclining Block Rate Evaluation Report, page 5-17, ll 11-14

- The class average elasticity due to RRA rate increases under a flat rate was not able to be estimated using empirical data. The evaluation used the assumption of -0.05 as the class average price elasticity to determine the natural conservation baseline.

1.9.2 Please provide any materials that BC Hydro used to inform this assumption.

RESPONSE:

Please refer to BC Hydro's response to COPE IR 1.9.1.

10.0 Reference: Exhibit B-1, Application, 5.2.3 2013 Residential Inclining Block Rate Evaluation Report, pages 5-17 to 5-18

The 2013 RIB Evaluation Report found that large consumers have higher elasticities than smaller consumers. Refer to the following 2013 RIB Evaluation Report findings:

- Large residential users consuming more than 2,400 kWh bi-monthly show a substantially higher than average response to higher prices. The 2013 RIB Evaluation Report indicates that the customer segment above 2,400 kWh of bi-monthly consumption has an estimated price elasticity of -0.16 to -0.18 (RIB Evaluation Report, pages vi, 20);
- Price elasticity is generally larger for customer segments with higher consumption. As discussed in section 5.2.2.2 above, customers living in single family detached homes generally have higher consumption than those living in other dwelling types. The 2013 RIB Evaluation Report finds that customers living in single family detached houses demonstrate higher price responsiveness than customers living in town houses, apartments or mobile homes (2013 RIB Evaluation Report, pages vi, 19). Section 5.2.2.2 also shows that customers with electric heat tend to have higher consumption than those that use other heating fuels. Price elasticity is higher among households with electric heat than those with non-electric heat (2013 RIB Evaluation Report, pages vi, 20); and
- Higher consumption is correlated with both higher awareness of the RIB rate and higher price elasticity; however, no firm conclusions can be drawn about how RIB awareness is related to customer price response (RIB Evaluation Report, pages vii, 28).

These results are all consistent with the RIB rate design assumptions that customers with a higher level of consumption tend to have a higher responsiveness to price.

1.10.1 Please confirm that with the RIB, high-use customers pay a higher average rate per kWh than they would if they were low-use customers?

RESPONSE:

With the existing RIB rate, customers who exceed the 1,350 kWh bi-monthly threshold will see their average energy rate increase with increases in consumption. Customers who consume below the 1,350 kWh bi-monthly threshold will see their average energy rate the same as the Step 1 rate.

10.0 Reference: Exhibit B-1, Application, 5.2.3 2013 Residential Inclining Block Rate Evaluation Report, pages 5-17 to 5-18

The 2013 RIB Evaluation Report found that large consumers have higher elasticities than smaller consumers. Refer to the following 2013 RIB Evaluation Report findings:

- Large residential users consuming more than 2,400 kWh bi-monthly show a substantially higher than average response to higher prices. The 2013 RIB Evaluation Report indicates that the customer segment above 2,400 kWh of bi-monthly consumption has an estimated price elasticity of -0.16 to -0.18 (RIB Evaluation Report, pages vi, 20);
- Price elasticity is generally larger for customer segments with higher consumption. As discussed in section 5.2.2.2 above, customers living in single family detached homes generally have higher consumption than those living in other dwelling types. The 2013 RIB Evaluation Report finds that customers living in single family detached houses demonstrate higher price responsiveness than customers living in town houses, apartments or mobile homes (2013 RIB Evaluation Report, pages vi, 19). Section 5.2.2.2 also shows that customers with electric heat tend to have higher consumption than those that use other heating fuels. Price elasticity is higher among households with electric heat than those with non-electric heat (2013 RIB Evaluation Report, pages vi, 20); and
- Higher consumption is correlated with both higher awareness of the RIB rate and higher price elasticity; however, no firm conclusions can be drawn about how RIB awareness is related to customer price response (RIB Evaluation Report, pages vii, 28).

These results are all consistent with the RIB rate design assumptions that customers with a higher level of consumption tend to have a higher responsiveness to price.

1.10.2 Has BC Hydro done any analysis to determine if it is the higher average rate per kWh or the effect of the marginal rate (the tier structure) that has the greatest effect on high-use customer behaviours in the RIB?

1.10.2.1 If so, please provide.
1.10.2.2 If not, please explain why BC Hydro has chosen not to determine what has the greater effect on customer behaviours.

RESPONSE:

The 2013 RIB Evaluation Report collected information on what customers that are always into Step 2 consider as their household's price of electricity. Please refer to Exhibit B-1, Appendix C-3B, page 138 of 609. As shown there, 62 per cent of

customers who were always into Step 2 and were previously aware of the RIB rate identified their household's price of electricity as the Step 2 price, or each of the Step 1 and Step 2 price depending on the point in time or their consumption in a billing period, as their household's price of electricity. This suggests that a significant percentage of customers are responding to the marginal rate.

The 2013 RIB Evaluation Report also collected information on how the different aspects of the tiered structure of the RIB rate provide an incentive to customers who are always into Step 2 to manage electricity. Please refer to Exhibit B-1, Appendix C-3B, page 139 of 609. As shown there, 71 per cent of customers who were always into Step 2, who were previously aware of the RIB rate structure and said that it serves as an incentive to manage electricity indicated that aspects of the tier structure of the RIB rate (the Step 2 price, the difference between the Step 1 and Step 2 prices or the consumption threshold) incent their household to manage electricity.

11.0 Reference: Exhibit B-1, Application, 5.2.5.2 Basic Charge Cost Recovery Increase, page 5-41, line 10

"The current RIB rate basic charge recovers 45 per cent of customer-related costs."

1.11.1 Please confirm that this figure represents the percentage recovery of fully allocated embedded costs.

RESPONSE:

Confirmed.

11.0 Reference: Exhibit B-1, Application, 5.2.5.2 Basic Charge Cost Recovery Increase, page 5-41, line 10

"The current RIB rate basic charge recovers 45 per cent of customer-related costs."

1.11.2 Please confirm that the impact of residential customer additions on all BC Hydro customer-related costs (i.e. the marginal customer-related cost associated with serving more customers) is much less than the average fully allocated embedded costs.

RESPONSE:

BC Hydro does not know if the marginal customer-related costs are less than the embedded customer-related costs because a detailed marginal COS study has not been undertaken or completed for the reasons discussed in section 3.4 of Exhibit B-1. In Attachment 4 to the Workshop 4 consideration memo (Exhibit B-1, Appendix C-2B, page 185 of 205), BC Hydro noted that a significant issue with marginal COS is how marginal customer-related costs would be determined and differentiated from non-marginal customer-related costs, including what customer operating expenses are necessary and legitimate marginal costs.

11.0 Reference: Exhibit B-1, Application, 5.2.5.2 Basic Charge Cost Recovery Increase, page 5-41, line 10

"The current RIB rate basic charge recovers 45 per cent of customer-related costs."

1.11.3 Please provide BC Hydro's best estimate of the marginal customer-related cost associated with serving more customers (marginal cost per additional account).

RESPONSE:

Please refer to BC Hydro's response to COPE 378 IR 1.11.2.

11.0 Reference: Exhibit B-1, Application, 5.2.5.2 Basic Charge Cost Recovery Increase, page 5-41, line 10

"The current RIB rate basic charge recovers 45 per cent of customer-related costs."

1.11.4 What impact would a revenue neutral elimination of the basic charge (where the lost basic charge revenue is recovered from higher energy rates) have on the following:

(i) the step 1 and step 2 rates assuming they were both increased proportionately;
(ii) the step 1 and step 2 rates assuming that the lost customer charge revenue was recovered from the step 1 rate;
(iii) conservation of electricity (under both step rate assumptions listed above);
(iv) the average low income customer's bill (under both step rate assumptions listed above)

RESPONSE:

Using the same vintage of modelling assumptions and inputs as Workshop 3 (Exhibit B-1 Appendix C-3A page 69 of 184), the outcomes are as follows:

	COPE 378 11.4i	COPE 378 11.4ii
RIB rate Step 1 (cents/kWh)	**8.50**	**9.07**
Step 2 (cents/kWh)	**12.74**	**11.95**
Basic charge ($/day)	**0**	**0**
Difference between the incremental conservation of alternative vs. status quo, from F2015 to F2016 (GWh) (COPE 11.4iii)	**105**	**23**
Typical Annual Bill using the median of Low Income Customers (COPE 11.4iv) ($)	**536.64**	**572.44**
Annual Bill difference from status quo ($)	**-34.29**	**1.51**

Elimination of the RIB rate basic charge does not align with the Bonbright fairness criterion. In addition, all Canadian electric utilities surveyed have residential basic charges; that is, no Canadian electric utility surveyed has a residential rate based solely on variable energy rates (refer to the Workshop 9/a slide deck at Exhibit B-1, Appendix C-3B page 28 of 609).

11.0 Reference: Exhibit B-1, Application, 5.2.5.2 Basic Charge Cost Recovery Increase, page 5-41, line 10

"The current RIB rate basic charge recovers 45 per cent of customer-related costs."

1.11.5 What impact would eliminating the basic charge for only BC Hydro's low income customers on a revenue neutral basis have on the step 1 and step 2 rates, conservation and the average bill of low income families (as listed in points (i) to (iv) in Q.4 above above).

RESPONSE:

Using the same vintage of modelling assumptions and inputs as Workshop 3 (Exhibit B-1 Appendix C-3A page 69), the outcomes are as follows:

	COPE 378 11.5i	**COPE 378 11.5ii**
RIB rate Step 1 (cents/kWh)	**8.02**	**8.08**
Step 2 (cents/kWh)	**12.03**	**11.95**
Basic charge for low income customers ($/day) assuming 10% of customers are low income as per REUS sample	**0**	**0**
Basic Charge for the non-low income customers ($/day)	**0.1764**	**0.1764**
Difference between the incremental conservation of alternative vs. SQ, from F2015 to F2016 (GWh) (COPE 11.5 iii)	**11**	**3**
Typical Annual Bill using the median of Low Income Customers (COPE 378 11.5 iv) ($)	**506.61**	**510.08**
Annual Bill difference from SQ ($)	**-64.32**	**-60.85**

Please also refer to BC Hydro's COPE IR 1.11.4 with respect to the fact that all surveyed Canadian electric utilities have a basic charge in their default residential rate.

In BC Hydro's view, there is no cost of service basis for waiving the basic charge for low income customers.

12.0 Reference: Exhibit B-1, Application, 5.4 Low Income Rate, page 5-58, ll 3-7

"In the context of UCA sections 58 to 61 rate setting, low income rates are likely to be seen as unduly preferential to low-income customers or unduly discriminatory to the remaining customers who subsidize those rates because the low income rate would be based on the personal characteristics of the customer, divorced from the cost to deliver electricity to the premises."

1.12.1 Please explain whether BC Hydro believes the RIB rate, which results in different cost recovery for people living in apartments/ condos as compared to single family dwellings (their personal housing characteristics), is any less 'unduly discriminatory' than a rate designed to lower energy costs for low income customers.

RESPONSE:

The existing RIB rate is by definition just, reasonable and not unduly discriminatory as it has been set by the Commission pursuant to the Commission's rate setting powers in sections 58 to 61 of the *UCA*. It is BC Hydro's view that the RIB rate results in higher average rates for larger consumers as compared to a flat rate, regardless of end uses to which that consumption is put to, or the personal characteristics of the end user. The RIB rate shifts costs to large consumers regardless of end use or personal characteristics.

It is BC Hydro's view that a low income rate, based on the personal characteristic of income, pursuant to which low income customers are charged a lower rate for electricity as compared to the remainder of the Residential rate class, does not have a cost of service basis. Therefore such a low income rate is generally not permitted under the *UCA*. As noted in section 5.1 of Exhibit B-1, BC Hydro's consideration of a low income rate will occur at the time BCOAPO introduces a specific low income rate proposal through intervener evidence.

Please also refer to BC Hydro's responses to BCOAPO IR 1.98.1 and CEC IR 1.46.1.

13.0 Reference: Exhibit B-1, 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, page 5-71, ll 14-21 and pages 5-71 and 5-72 lines 23-27

- As the RIB rate has been in place for almost seven years, the only sound method to gauge bill impacts to low income customers is to compare the RIB rate to an alternative had the RIB rate not been in place. BC Hydro proposes that the flat energy rate modelled for the 2015 stakeholder engagement process and described in section 5.2.4.1 above serve as the counter-factual. As noted in Table 5-3 above, BC Hydro estimates that with a flat rate, in F2017 80 per cent of low income accounts will experience bill impacts greater than 10 per cent, and 47 per cent greater than 20 per cent.

Minister RIB Report Letter Question 3

As illustrated in section 5.2.4.1 above, BC Hydro modelled the bill impacts of moving from the RIB rate to a flat rate by dwelling type (apartments) and for customers using electric space heating. BC Hydro also proposes to model the bill impacts of moving from the RIB rate to a flat rate for customers in communities that do not have access to natural gas.

1.13.1 Has BC Hydro identified and analyzed alternative rate structures or measures in order to identify opportunities to assist low income customers?

1.13.1.1 If so, please provide the materials generated.
1.13.1.2 If not, please explain why BC Hydro has declined to perform this analysis.

RESPONSE:

Yes:

- **Please refer to BC Hydro's response to BCOAPO IR 1.89.1, which outlines how BC Hydro through the BC Hydro 2015 stakeholder engagement process examined three different alternatives three-step rate designs, two of which were advanced by BCOAPO for purposes of delivering bill relief at low levels of consumption. That response also outlines how BC Hydro reviewed the impacts on low income customers as part of its analysis of the RIB rate. The materials generated are referenced in BC Hydro's response to BCOAPO IR 1.89.1;**

- **BC Hydro is in the process of reviewing potential low income terms and conditions. Please refer to Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1; and**

- **Finally although BC Hydro is of the view that a low income rate is likely unduly discriminatory/unduly preferential, it conducted a jurisdictional review of low income rates/low income terms and conditions/low income DSM programs; refer to Exhibit B-1, Appendix C-3D.**

13.0 Reference: Exhibit B-1, 5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter, page 5-71, ll 14-21 and pages 5-71 and 5-72 lines 23-27

- As the RIB rate has been in place for almost seven years, the only sound method to gauge bill impacts to low income customers is to compare the RIB rate to an alternative had the RIB rate not been in place. BC Hydro proposes that the flat energy rate modelled for the 2015 stakeholder engagement process and described in section 5.2.4.1 above serve as the counter-factual. As noted in Table 5-3 above, BC Hydro estimates that with a flat rate, in F2017 80 per cent of low income accounts will experience bill impacts greater than 10 per cent, and 47 per cent greater than 20 per cent.

Minister RIB Report Letter Question 3

As illustrated in section 5.2.4.1 above, BC Hydro modelled the bill impacts of moving from the RIB rate to a flat rate by dwelling type (apartments) and for customers using electric space heating. BC Hydro also proposes to model the bill impacts of moving from the RIB rate to a flat rate for customers in communities that do not have access to natural gas.

1.13.2 Does BC Hydro agree that there are rate structures or measures designed to assist low income customers that could do so in a more comprehensive, fair and consistent manner than the current RIB?

1.13.2.1 If not, please explain.

RESPONSE:

While it is unclear what COPE 378 means by the term 'fair' as used in the IR, BC Hydro uses the term 'fair' as used by Bonbright, that is, fair apportionment of costs among customers. In BC Hydro's view, a low income rate, based on the personal characteristic of income pursuant to which low income customers are charged a lower rate for electricity as compared to the remainder of the Residential rate class, would be divorced from the nature and quality of the associated service, including cost of service. Please refer to BC Hydro's response to COPE 378 IR 1.12.1.

14.0 Reference: Exhibit B-1, Application, 6.2.3.1 SGS Rate Structure, pages 6-10 to 6-11

"A SGS demand charge would also require a demand meter which not all SGS customers have. The requirement for a demand meter on all SGS customers makes the demand charge less practical and cost-effective to administer."

1.14.1 Has BC Hydro analyzed what capabilities Smart Meters provide for better alignment of rates with costs? For example, has it analyzed whether its Smart Meters are capable of metering energy use on a Time-of-Use basis that would enable, should government policy allow, differential rates for peak versus non-peak hours and on a seasonal basis? If so please provide the relevant studies or summaries

RESPONSE:

Please refer to BC Hydro's responses to COPE 378 IRs 1.4.2 and 1.5.1.

14.0 Reference: Exhibit B-1, Application, 6.2.3.1 SGS Rate Structure, pages 6-10 to 6-11

"A SGS demand charge would also require a demand meter which not all SGS customers have. The requirement for a demand meter on all SGS customers makes the demand charge less practical and cost-effective to administer."

1.14.2 Does BC Hydro agree that this pricing model would address some of the efficiency and fairness rationales of demand charges?

1.14.2.1 If not, please explain why not.

RESPONSE:

BC Hydro assumes that the phrase "pricing model" in the IR refers to implementing an SGS rate with a demand charge.

BC Hydro is unclear as to what efficiency rationale(s) the question above is referring to.

BC Hydro rejects a demand charge for the SGS rate. While a demand charge may support the Bonbright fairness criterion in that it would recover some portion of demand-related costs, it would increase the complexity of the SGS rate. BC Hydro notes that most Canadian jurisdictions do not bill smaller general service customers separately for demand. BC Hydro's reasons for rejecting a demand charge for the SGS rate are laid out in section 6.2.3.1 of Exhibit B-1, including the fact that during the 18-month long stakeholder engagement process, no stakeholder suggested that the SGS rate structure should have a demand charge.

15.0 Reference: Exhibit B-1, Application, 6.2.4 BC Hydro Proposal and Stakeholder Engagement, page 6-12, ll 21-24

In BC Hydro's view, there are no rate design objectives to be traded off. Increasing the SGS basic charge recovery to 45 per cent of customer-related costs aligns with the Bonbright fairness criterion by matching embedded cost recovery in rates with cost causation. Moreover, there is no conflict with the economic efficiency criterion:

1.15.1 Please provide BC Hydro's best estimate of the marginal customer-related cost associated with serving more SGS customers (marginal cost per additional account).

RESPONSE:

BC Hydro has not done a marginal COS study for customer-related costs. Please refer to BC Hydro's response to COPE IR 1.11.3.

15.0 Reference: Exhibit B-1, Application, 6.2.4 BC Hydro Proposal and Stakeholder Engagement, page 6-12, ll 21-24

In BC Hydro's view, there are no rate design objectives to be traded off. Increasing the SGS basic charge recovery to 45 per cent of customer-related costs aligns with the Bonbright fairness criterion by matching embedded cost recovery in rates with cost causation. Moreover, there is no conflict with the economic efficiency criterion:

1.15.2 How does that compare to the average embedded fully allocated costs per account?

RESPONSE:

Please refer to BC Hydro's response to COPE IR 1.15.1.

16.0 Reference: Exhibit B-1, Application, 6.3.5 BC Hydro Proposal and Stakeholder Engagement, page 6-32, ll 11-15 and page 6-37

"BC Hydro acknowledged that as a result of the proposed increase to the demand charge, the MGS flat energy rate under its proposal drops below the lower bound of the energy LRMC range (F2017: MGS flat energy rate is 8.54 cents/kWh and the lower end of the energy LRMC range is 9.46 cents/kWh)."

On page 6-37, BC Hydro notes that high load-factor customers who can make more efficient use of the system will benefit the most from this proposal and that AMPC supported a higher demand charge and lower energy rate.

1.16.1 What analysis has BC Hydro done to compare the efficiency and conservation losses that will result from lower energy rates relative to the efficiency gain resulting from the higher demand rates?

RESPONSE:

BC Hydro considered all of the Bonbright criteria listed in Exhibit B-1, Table 2-7 in proposing the 35 per cent demand cost recovery for the MGS demand charge. Please refer to Exhibit B-1, page 6-30 for a discussion of BC Hydro's consideration of increasing the demand-related cost recovery from 15 per cent to 35 per cent.

BC Hydro did not explicitly quantify the efficiency differences between a slightly lower MGS flat energy rate with a 35 per cent demand cost recovery as compared to a MGS flat energy rate with a 15 per cent demand cost recovery. BC Hydro considers both rate options to be economically efficient, as both energy rates are reflective of the energy LRMC, as shown in Exhibit B-1, Table 2-6. BC Hydro notes that there is only an 8.7 per cent difference in the respective flat energy rates. With the elasticity assumption of -0.05, that would translate to a maximum difference in natural conservation of less than one per cent.

BC Hydro did not estimate conservation differences between the two rate options, but believes that such an analysis would show minimal differences in conservation because of (1) the counteracting impacts of demand and energy charge changes on customer bills, and (2) the poor understanding of customers regarding their current rates, which makes it difficult for customers to respond to price signals.

16.0 Reference: Exhibit B-1, Application, 6.3.5 BC Hydro Proposal and Stakeholder Engagement, page 6-32, ll 11-15 and page 6-37

"BC Hydro acknowledged that as a result of the proposed increase to the demand charge, the MGS flat energy rate under its proposal drops below the lower bound of the energy LRMC range (F2017: MGS flat energy rate is 8.54 cents/kWh and the lower end of the energy LRMC range is 9.46 cents/kWh)."

On page 6-37, BC Hydro notes that high load-factor customers who can make more efficient use of the system will benefit the most from this proposal and that AMPC supported a higher demand charge and lower energy rate.

1.16.2 Is there any evidence of an overall economic efficiency gain or loss?

1.16.2.1 If so, please provide.

RESPONSE:

Please refer to BC Hydro's response to COPE IR 1.16.1.

17.0 Reference: Exhibit B-1, Application, 6.4.4.2 Screening of Alternatives and Stakeholder Engagement, page 6-55, ll 4-9

"However, there is a trade-off between the customer understanding and acceptance and the economic efficiency criteria because the flat energy rate would not be reflective of LRMC (F2017: LGS flat energy rate is 5.37 cents/kWh with demand charge cost recovery at 65 per cent, and the lower end of the energy LRMC range is 9.46 cents/kWh)."

1.17.1 Has BC Hydro estimated the efficiency (and conservation) impact of having an energy rate roughly 40% below the lower bound of the LRMC? For example has it estimated the how much higher LGS energy demand will be at its proposed energy rate as compared to a mid-point estimate of the LRMC?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.75.2.

17.0 Reference: Exhibit B-1, Application, 6.4.4.2 Screening of Alternatives and Stakeholder Engagement, page 6-55, ll 4-9

"However, there is a trade-off between the customer understanding and acceptance and the economic efficiency criteria because the flat energy rate would not be reflective of LRMC (F2017: LGS flat energy rate is 5.37 cents/kWh with demand charge cost recovery at 65 per cent, and the lower end of the energy LRMC range is 9.46 cents/kWh)."

1.17.2 Does BC Hydro have any plans to address the potential adverse efficiency impacts of having an energy rate so far below the LRMC?

1.17.2.1 If so please indicate what they are.
1.17.2.2 If not, please indicate why not.

RESPONSE:

While BC Hydro acknowledges that the proposed LGS flat energy rate is below the lower end of the energy LRMC, it is not clear that there will be "adverse efficiency impacts". For example, there will be no impact on rate structure conservation given the F2014 LGS and MGS Evaluation Report finding that the LGS two-part rate has delivered lower than expected conservation savings (77 GWh/year) with a declining confidence in the persistence of savings (85 per cent level of statistical significance). The combination of low awareness, low demonstrated understanding and declining savings imply that much of the evaluated LGS savings were the result of short persistence savings, such as operational and maintenance measures, that were allowed to lapse. This implies a declining confidence in the persistence of LGS savings. BC Hydro has forecasted zero conservation savings from the LGS two-part rate if it is to continue.

Given the uncertainty as to whether there are any potential adverse efficiency impacts, BC Hydro has no plans at this time to address such potential impacts.

18.0 Reference: Exhibit B-1, Application, 6.4.4.2 Screening of Alternatives and Stakeholder Engagement, page 6-56, ll 71-21

During the stakeholder engagement process, AMPC stated that the Bonbright fairness criterion supports increasing the LGS demand cost recovery to 65%. BC Hydro's proposal is to increase the LGS demand cost recovery to 65%.

1.18.1 What analysis has BC Hydro done to assess whether this proposal would be supported by the Bonbright efficiency criterion? More specifically, similar to questions posed concerning the proposed increase in the MGS demand rate, what analysis has BC Hydro done to compare the efficiency (and conservation) loss from lower LGS energy rates relative to the efficiency gain resulting from higher demand rates?

1.18.1.1 If BC Hydro has not done any analysis to assess this, please explain why not.

RESPONSE:

BC Hydro has not performed an analysis of efficiency and conservation differences for the two LGS flat rate options.

As stated in BC Hydro Exhibit B-1, section 6.4.5.1, BC Hydro's proposed LGS flat energy rate prioritizes customer understanding and acceptance. The difference in economic efficiency of the BC Hydro proposed flat energy rate and the Sensitivity (50 per cent Demand Recovery) rate is not of significance because of the large deviation of both energy rates from LRMC (5.37 cents/kWh for the BC Hydro proposal and 5.98 cents/kWh for the 50% Demand Recovery Sensitivity case, relative to 9.46 cents/kWh for F2017 LRMC lower value). BC Hydro notes that there is only a 10 per cent difference in the flat energy rates under BC Hydro's proposal and the Sensitivity case. With the elasticity assumption of -0.05, that would translate to a maximum difference in natural conservation of about 1 per cent.

18.0 Reference: Exhibit B-1, Application, 6.4.4.2 Screening of Alternatives and Stakeholder Engagement, page 6-56, ll 71-21

During the stakeholder engagement process, AMPC stated that the Bonbright fairness criterion supports increasing the LGS demand cost recovery to 65%. BC Hydro's proposal is to increase the LGS demand cost recovery to 65%.

1.18.2 Is there any evidence of an overall economic efficiency gain or loss?

1.18.2.1 If so, please provide.

RESPONSE:

Please refer to BC Hydro's response to COPE IR 1.18.1.

19.0 Reference: Exhibit B-1, Application, 6.4.5.1 LGS Flat Energy Rate, page 6-60, ll 18-20

"…the gains in simplification in moving to a flat energy rate appear to be worth the apparent small loss in economic efficiency in the status quo LGS rate design."

1.19.1 What is BC Hydro's latest available estimate of the economic conservation potential in the LGS section expressed both in GWh and as a percentage of total load?

RESPONSE:

BC Hydro respectfully declines to provide the information requested in this IR on the basis that the requested information is not relevant to and cannot aid in the review of the 2015 RDA or the orders sought with respect to it. The 2007 CPR cannot assist with the decision as to whether the existing LGS two-part rate structure should continue or be replaced with BC Hydro's proposed flat LGS rate. The reference quoted in the IR does not concern conservation potential; rather, it sets out BC Hydro's observation that the proposed LGS flat rate entails no loss of rate structure conservation because BC Hydro is forecasting zero rate structure conservation from the existing LGS rate going forward given the two evaluation report results.

In any event, BC Hydro's last CPR was conducted in 2007. Moreover, conservation potential estimates can only be segmented by customer sector (e.g., residential, commercial, industrial) and not by specific rate classes. For these two reasons, any estimate of LGS economic potential would be uncertain. As set out in BC Hydro's response to BCSEA IR 1.10.1, BC Hydro is currently conducting a joint CPR, which will provide an updated view of the conservation potential, with results expected in F2017.

19.0 Reference: Exhibit B-1, Application, 6.4.5.1 LGS Flat Energy Rate, page 6-60, ll 18-20

"…the gains in simplification in moving to a flat energy rate appear to be worth the apparent small loss in economic efficiency in the status quo LGS rate design."

1.19.2 What was BC Hydro's estimate of the extent to which that economic conservation potential might be realized under the rate proposals in the DSM Option 4 from BC Hydro's 2013 IRP?

RESPONSE:

The LGS and MGS flat rate proposals are not considered to be 'demand-side measures' as defined in section 1 of *CEA*. The LGS and MGS flat rate proposals will deliver natural conservation, estimated through the -0.05 elasticity assumption BC Hydro uses for the class average price elasticity to determine the natural conservation baseline.

To provide context for the remainder of the response, BC Hydro provides definitions of the three levels of conservation potentials:

- **Technical potential – this theoretical case provides the broadest and highest definition of savings potential. Technical potential does not take into account the cost-effectiveness of potential DSM measures;**

- **Economic potential – represents the adoption of all cost-effective conservation measures within a defined price threshold; and**

- **Achievable potential – represents the portion of economic potential that can be reasonably achieved through DSM initiatives by overcoming the various barriers in the marketplace.**

BC Hydro assumed about 150 GWh/yr for the commercial rate portion of Option 4 as a working assumption, however as noted in COPE 378 1.1.1, Option 4 was considered too conceptual and uncertain to be viable for resource planning in the 2013 IRP. For this reason it is not appropriate to consider this high level GWh/yr figure for the commercial rate portion of Option 4 as an achievable portion of the economic potential. To be clear, the commercial rate portion of Option 4 has no achievable potential.

19.0 Reference: Exhibit B-1, Application, 6.4.5.1 LGS Flat Energy Rate, page 6-60, ll 18-20

"…the gains in simplification in moving to a flat energy rate appear to be worth the apparent small loss in economic efficiency in the status quo LGS rate design."

1.19.3 What economic conservation potential is expected to be realized with the rates proposed in this Application?

RESPONSE:

BC Hydro is not forecasting any rate structure conservation savings attributed to the proposed LGS flat rate, nor is it forecasting any rate structure conservation savings attributed to the existing LGS rate. The F2014 LGS and MGS Evaluation Report found that customer response to the existing LGS two-part baseline rate was considerably less than forecast; consequently, forecast savings for the LGS rate was adjusted to zero.

20.0 General Issues Raised at the Workshops

During the RDA workshops, in response to a COPE 378 query, BC Hydro stated that they are approximately 5 to 10 years away from developing the necessary IT infrastructure to engage in complex billing practices such as pre-paid billing or automatic conservation incentives based on previous power use.

1.20.1 Can BC Hydro describe in more detail what it will achieve and when during that timeline?

RESPONSE:

BC Hydro has a number of opportunities to improve the customer billing experience and lay the foundation for future services and initiatives. Specific projects that have been committed include the following:

- **MyHydro EDX Project – Described in BC Hydro's response to BCUC IR 1.134.3. To be launched in early 2016;**
- **On-Bill Incentive Pay-Out – Enable the ability for DSM program incentive payments and rebates to appear as credits on bills instead of being processed as separate cheques. To be launched late 2016; and**
- **Customer Billing Project – Redesign BC Hydro's bills to make them easier to understand and are designed for the customer's channel of choice. To be released in multiple stages starting in 2017, pending approval of the implementation business case.**

In addition, capability improvements that are planned but not yet committed within the next three years:

- **Improving payment options, such as exploring Interac online and similar payment mechanisms; and**
- **Improving billing and consumption related notifications to provide customers with pre-bill high consumption/high bill warnings and anomaly alerts, as well as to improve account-related notification preference options.**

While possible to introduce complex rates such as pre-paid billing prior to some of these initiatives, BC Hydro would be opposed to such a course of action. The above projects will provide foundational improvements that benefit all customers and so BC Hydro has prioritized them first. Moreover, these improvements will ensure a better customer experience if more complex rates are introduced, and thereby increase the likelihood of their success.

20.0 General Issues Raised at the Workshops

During the RDA workshops, in response to a COPE 378 query, BC Hydro stated that they are approximately 5 to 10 years away from developing the necessary IT infrastructure to engage in complex billing practices such as pre-paid billing or automatic conservation incentives based on previous power use.

1.20.2 Is an expansion of the online customer service and billing infrastructure currently underway?

1.20.2.1 If so, what is the expansion going to achieve or facilitate relating to complex billing practices.

RESPONSE:

Please refer to BC Hydro's response to COPE IR 1.20.1.

20.0 General Issues Raised at the Workshops

During the RDA workshops, in response to a COPE 378 query, BC Hydro stated that they are approximately 5 to 10 years away from developing the necessary IT infrastructure to engage in complex billing practices such as pre-paid billing or automatic conservation incentives based on previous power use.

1.20.3 Is an expansion relating to billing practices planned for the future?

1.20.3.1 If so, what is the timeline to begin and finish this expansion and what is its specific intended purpose?

RESPONSE:

Please refer to BC Hydro's response to COPE IR 1.20.1.

20.0 General Issues Raised at the Workshops

During the RDA workshops, in response to a COPE 378 query, BC Hydro stated that they are approximately 5 to 10 years away from developing the necessary IT infrastructure to engage in complex billing practices such as pre-paid billing or automatic conservation incentives based on previous power use.

1.20.4 What is the reason for such a lengthy timeline?

RESPONSE:

Please refer to BC Hydro's response to COPE IR 1.20.1.

20.0 General Issues Raised at the Workshops

During the RDA workshops, in response to a COPE 378 query, BC Hydro stated that they are approximately 5 to 10 years away from developing the necessary IT infrastructure to engage in complex billing practices such as pre-paid billing or automatic conservation incentives based on previous power use.

1.20.5 Has BC Hydro considered any of the following more flexible or conservation-oriented rate design forms, and if so, what have they determined about each:

i) rebates or incentives for demonstrated conservation;
ii) time of use and other efficient or price-responsive demand options;
iii) residential demand charges or minimum bills;
iv) micro-loans built into rates for efficiency improvements; and
v) pre-paid accounts.

RESPONSE:

This IR is posed in the context a potential voluntary Residential prepayment option. BC Hydro responds to each Residential "rate design form" advanced by COPE 378 in this IR as follows:

i) Rebates or incentives for demonstrated conservation

- **In BC Hydro's view, there is no need for a Residential rate bearing similarities to the existing MGS/LGS rates, which provide credits. In BC Hydro's view such a rate would require a customer baseline, which would not be viable (refer to section 5.2.4 of Exhibit B-1, page 5-20, lines 17 to 20). The existing default RIB rate was developed to provide a signal for energy conservation and has delivered conservation. In addition, BC Hydro has a suite of Residential DSM programs that provide incentives; refer to Table 5-16 of Exhibit B-1.**

ii) Time of use and other efficient or price-responsive demand options

- **Please refer to BC Hydro's response to COPE IR 1.5.1.**

iii) Residential demand charges or minimum bills

- **BC Hydro modelled and assessed an alternative Residential minimum charge, as separate from a basic charge, in Workshop 3 and Workshop 9b, and provided further comment in its consideration memos in respect of those workshops, which can be referenced in Appendix C-3A and C-3B, respectively, of Exhibit B-1. As discussed in section 4.2 of the Workshop 9a/9b consideration memo, at Appendix C-3B of Exhibit B-1, pages 337 to 339 of 609, BC Hydro decided to not pursue a minimum charge, concluding that it would**

yield minimal benefit to customers through a small reduction in the Step 1 rate with the risk that some low income customers will be adversely affected. This position was supported by BCSEA, BCOAPO and FNEMC.

- **With respect to a potential Residential demand charge, please refer to BC Hydro's response to COPE IR 1.6.3.**

iv) Micro loans built into rates for efficiency improvements

- **BC Hydro has not considered micro-loans built into rates. No stakeholder identified this as an option during the 18-month 2015 RDA stakeholder engagement process.**

v) Pre-paid accounts

- **A voluntary prepayment option for Residential customers was raised by stakeholders in the RDA stakeholder engagement process; such an option would allow payment for a set value of electricity in advance of consumption, rather than paying monthly or bi-monthly after electricity is used. BC Hydro committed to address such an option as part of RDA Module 2.**

20.0 General Issues Raised at the Workshops

During the RDA workshops, in response to a COPE 378 query, BC Hydro stated that they are approximately 5 to 10 years away from developing the necessary IT infrastructure to engage in complex billing practices such as pre-paid billing or automatic conservation incentives based on previous power use.

1.20.5.1 Does BC Hydro intend to pursue investigations or development of programs in any of these areas for inclusion in future rate design applications?

1.20.5.1.1 If so, when is BC Hydro planning to do so?
1.20.5.1.2 If not, please explain why not.

RESPONSE:

Please refer to BC Hydro's response to COPE IR 1.20.5.

20.0 General Issues Raised at the Workshops

During the RDA workshops, in response to a COPE 378 query, BC Hydro stated that they are approximately 5 to 10 years away from developing the necessary IT infrastructure to engage in complex billing practices such as pre-paid billing or automatic conservation incentives based on previous power use.

1.20.6 In conjunction with conservation-oriented rate design, is BC Hydro considering any incentive or funding programs for retrofitting, efficiency systems, and other conservation-based upgrades?

RESPONSE:

BC Hydro currently offers a range of DSM initiatives for residential, commercial and industrial customers that provide incentives to customers to retrofit and/or invest in energy efficient systems. The residential and industrial initiatives are designed to complement energy savings realized through the RIB rate and RS 1823.

20.0 General Issues Raised at the Workshops

During the RDA workshops, in response to a COPE 378 query, BC Hydro stated that they are approximately 5 to 10 years away from developing the necessary IT infrastructure to engage in complex billing practices such as pre-paid billing or automatic conservation incentives based on previous power use.

1.20.6.1 Is BC Hydro considering the implementation of any of the programs listed above to enhance existing programs or to offset efficiency trade-offs inherent in the current proposal?

RESPONSE:

As noted in BC Hydro's response to COPE IR 1.20.1, certain foundational improvements are required to enable the successful introduction of complex billing practices. BC Hydro is always interested in enhancing existing DSM programs and billing practices; however, for the reasons discussed in BC Hydro's response to COPE IR 1.20.1 it is premature to contemplate implementation of prepaid billing or other complex billing practices.

BC Hydro also notes that while practices such as pre-paid billing may offer both customer and utility benefits, the actual level of customer interest in adopting this type of rate is unknown. Given the level of investment necessary to launch a program such as pre-paid billing, it is prudent to thoroughly assess costs, benefits and customer adoption before committing to implementation.

Diane Roy
Director, Regulatory Services

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November 17, 2015

Via Email
Original via Mail

British Columbia Hydro and Power Authority
Regulatory & Rates Group
16th Floor – 333 Dunsmuir Street
Vancouver, BC
V6B 5R3

Attention: Mr. Tom Loski, Chief Regulatory Officer

Dear Mr. Loski:

Re: British Columbia Hydro and Power Authority (BC Hydro) 2015 Rate Design Application (the Application)

FortisBC Energy Inc. and FortisBC Inc. (collectively FortisBC) Information Request (IR) No. 1 to BC Hydro

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In accordance with the Regulatory Timetable set by the British Columbia Utilities Commission Order G-156-15A, attached is FortisBC IR No. 1 to BC Hydro on the above noted Application.

If further information is required, please contact Michelle Carman at 604-592-7458.

Sincerely,

on behalf of FORTISBC

Original signed by: Michelle Carman

For: Diane Roy

Attachment

cc : Commission Secretary
Registered Parties (email only)

REQUESTOR NAME: **FortisBC Energy Inc. and FortisBC Inc. (FortisBC or the Companies)**

INFORMATION REQUEST ROUND NO: **1**

TO: BRITISH COLUMBIA HYDRO & POWER AUTHORITY

DATE: **November 17, 2015**

PROJECT NO:

APPLICATION NAME: **BC Hydro 2015 Rate Design Application**

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1.0 Topic: F2016 Cost of Service Study and Methodology
Reference: Chapter 3, Table 3-6, Page 3-36; BCUC IR 1.17.1

Table 3-6 R/C Ratios

	R/C Ratios		
	Final F2016 COS Study results		F2013 Fully Allocated COS
Rate Class	Final Study filed in the RDA (%)	Draft F2016 COS study posted to RDA website in February 2015 (%)	Filed on February 8, 2014 with the Commission (using 2007 RDA decision) (%)
COLUMN	A	B	C
Residential	93.9	93.9	89.8
SGS	112	112	126.7
MGS	117.1	120.5	120.8
LGS	100.9	99.7	102.1
Irrigation	85.1	85.2	86.6
Street Lighting	134.1	134.1	115.7
Transmission	101.4	101.5	104.4
Total Classes	100	100	

1.1 Please reproduce Table 3-6 with an additional column (i.e. Column (D)) that provides the R/C ratios for F2016 using the same 2007 RDA COS allocation methodologies that generate the results in Column C for F2013.

2.0 Topic: F2016 Cost of Service Study and Methodology
Reference: Chapter 3, Table 3-1, Page 3-10; Table 3-6, Page 3-36

Table 3-1 provides descriptions of the COS allocation methodology changes that BC Hydro has adopted in its F2016 COS study relative to the corresponding 2007 RDA decision COS allocation determinations.

2.1 Please complete the table below. For column (2), please provide the R/C ratios for F2016 using the methodologies approved in the 2007 RDA decision (i.e. the additional column requested in question 2.1) and for the next five columns (columns (3) – (7)), please provide the incremental percentage impact on the R/C ratios from sequentially introducing each of the five methodology changes set out in Table 3-1. For column (8), please provide a summation of column (2) and the incremental percentages from each of the five methodology changes set out in Table 3-1.

	Revenue to Cost (R/C) Ratios (%)							
		Incremental Effects of Table 3-1 COS Methodology Changes						
Rate Class	F2016 R/C Ratios using 2007 RDA	DSM 90% Gen / 5% Trans / 5% Dist	Heritage supply 55% energy / 45% demand	IPP costs 93% energy / 7% demand	Sub-function alize the Distribut ion system:	Classify cust care costs 100% cust	Sum of Column (2) through (7)	Final Study filed in the RDA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Illustrative Example[1]	93.2	0.3	0.9	0.5	1.2	1.1	97.2	97.5
Residential								93.9
SGS								112.0
MGS								117.1
LGS								100.9
Irrigation								85.1
Street Lighting								134.1
Transmission								101.4
Total Classes	100.0							100.0

[1] This example is for illustrative purposes only to demonstrate the intent of the question and is not based on evidence provided in this Application

2.1.1 Please provide an explanation of the differences if the results of the summation in column (8) are different from the Final Study F2016 R/C ratios identified in first column of Table 3-6 (reproduced in column (9) above).

3.0 Topic: Rate Class Segmentation, MGS and LGS Breakpoint
Reference: Chapter 4, Figure 4-2, Page 4-11

On page 4-11 BCH states that "it is difficult to pinpoint a clear breakpoint in the downward trend of unit costs".

3.1 Please confirm that a clear breakpoint between MGS and LGS cannot be identified with disaggregated data.

4.0 Topic: Rate Class Segmentation, Transmission Service Rate Class
Reference: Chapter 4, Table 4-4 and Attachment C-3B, Slide 28

In Table 4-4 on Page 4-21, BCH states that "the differential between an individual customer's R/C ratio and the Transmission Service rate class average is greater for some customers (#12 and #13 on Slide 40) than it is for these two utilities".

4.1 Please confirm that, relative to the class averages, there are differences in load characteristics seen for other customers within the Transmission rate classes (i.e. customers other than FortisBC and New Westminster).

4.1.1 As shown on Slide 39 of Attachment C-1B, there are a number of customers that have a higher than average coincidence factor as compared to the Transmission Service Rate class average (as provided in Table 4-3) or a lower load factor as compared to the class average or FortisBC and New Westminster. Please explain why BCH has not proposed changes for these customers similar to the change proposed for FortisBC and New Westminster?

5.0 Topic: Rate Class Segmentation, Transmission Service Rate Class and F2016 Cost of Service Study
Reference: Chapter 4, Page 4-19, row 11 to 14.

BC Hydro used F2014 hourly load data for each Transmission customer to assign F2016 costs to individual customers on a pro rata basis using common allocators from the F2016 COS study

5.1 Please provide a detailed breakdown of the cost allocation in a comparable format to Schedule 4.1 of Appendix C-2C. Please also include a summary of which common allocators were used.

5.2 Please provide the estimated range of R/C ratios for all of the more than 100 customers in the Transmission Service Rate Class whose individual R/C ratio was estimated and used in the Individual Customer R/C ratio analysis (see page 4-19, lines 10-19). Please provide this by number of customers in increments of 5% as demonstrated in the table below:

R/C Ratio Range	Number of Customers
70% to 75%%	0
75% to 80%	1
80% to 85%	1
Etc.	

6.0 Topic: Residential Inclining Block
Reference: Chapter 5, Page 5-42 and Attachment C-3B, Slide 28

On page 5-42 Saskpower is identified as having the lowest percentage (at 22%) of allocated fixed costs recovered by the residential basic charge and this is

presented as a comparator with BC Hydro's basic charge recovering 45% of allocated fixed costs, yet at $20.22/month for City customers and $29.22/month for rural customers, the Saskpower residential basic charge is roughly 4 to 6 times BC Hydro's residential basic charge of $5/month.

6.1 Please confirm that based on the information provided in Attachment C-3B, Slide 28, the calculated value for the annual fixed cost allocation for Saskpower residential customers is in the range of $1,103 / year ($20.22 per month City x 12 months per year /22%) to $1,592/year ($29.19 per month Rural x 12 months per year / 22%) and for BC Hydro residential customers is approximately $133 per year ($5 per month x 12 months per year / 45%).

6.2 Please list the key factors and differences in cost allocation approach that explain why Saskpower's allocated fixed costs per customer per year for residential customers are roughly 8 to 12 times as large as BC Hydro's.

6.3 Please confirm that all of the residential basic charges presented in the Canadian jurisdiction survey (Appendix C-3B, Slide 28) are between 2 and 6 times the level of BC Hydro’s RIB basic charge (with the exception of Manitoba Hydro’s residential basic charge for <200 Amp. Service, which is about 1.5 times the RIB basic charge).

7.0 Topic: Residential Inclining Block
Reference: Chapter 5, Page 5-42 and Attachment C-3B, Slide 28

"The current RIB rate basic charge recovery of 45 per cent is in the range of Canadian electric utility residential rate basic charge cost recovery but at the lower end of the range". Figure 5-18 which depicts BC Hydro's requested RIB pricing approach and shows the RIB Step 2 rate as exceeding the upper limit of the Energy LRMC.

7.1 Has BC Hydro considered making a one-time shift in RIB revenue recovery from the Step 2 rate to the basic charge, followed by adopting BC Hydro's proposed rate change approach (see Application, p.5-33) of applying the yearly approved revenue requirement increases to each of the RIB rate components?

7.1.1 Does BC Hydro agree that such a one-time shift could be used to bring the Step 2 rate within the LRMC range while at the same time increasing the RIB basic charge and related revenue recovery to a level more typical for Canadian electric utilities?

7.1.2 How much cost shifting of this nature could be done without causing unacceptable rate impacts for customers in particular sub-segments of the residential class?

7.1.3 Please provide rate impact analyses of one-time RIB revenue recovery shifts from the Step 2 rate to the basic charge which increase the basic charge by (i) $2.00/month, and (ii) $4.00/month. Assume in both cases that, other than the one-time revenue shift, BC Hydro's proposed rate change approach of applying the

approved revenue requirement increases to each of the RIB rate components applies for F2017 to F2019.

7.1.3.1 Relative to BC Hydro's proposed approach without any intra-class revenue shifting, please explain which residential sub-segments are most affected by the one-time revenue shift to the basic charge, and provide a summary of the bill impacts on the most-affected sub-segments in both percentage terms and annual dollar amounts.

8.0 Topic: General Service
Reference: Chapter 6

8.1 Please provide a bill frequency analysis, in a table format, for SGS, MGS & LGS. For SGS, please show the number of customers in blocks of annual consumption of 5,000 kWh; for MGS, please show the number of customers in blocks 25 kW to 175 kW and increments 5,000 kWh to 600,000 kWh; and for LGS, please show the number of customers in blocks of 25kW starting from 125kW to 500kW, corresponding to increments 10,000 kWh starting from 350,000 kWh to 1,000,000 kWh.

9.0 Topic: Freshet Pilot
Reference: Chapter 7, Page 7-40 and Appendix C-5B

One of the identified drivers of Freshet rate take-up is the customer's ability to increase production capacity. It is likely in many cases that increasing production would depend on customers investing new capital to increase production capacity.

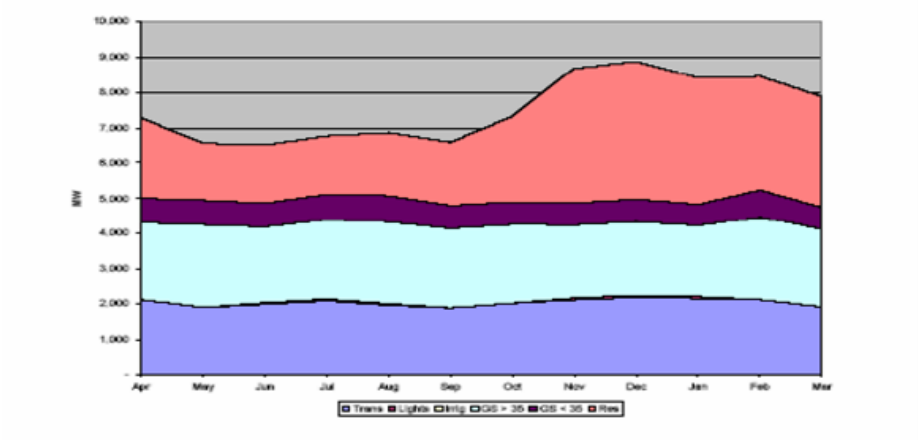
9.1 Please confirm that typically customers prefer longer term assurance before making capacity investments and given that the pilot is only two years in duration, customer take-up of the pilot may be limited and as such, may not be representative of potential take-up if the rate was permanent.

9.1.1 Please confirm that BC Hydro has made an assessment of whether there is broad interest in the Freshet Pilot program amongst all RS 1823 customers?

9.1.2 If confirmed, please provide the findings of the assessment, including whether RS 1823 customers in certain industry sectors were less supportive of the proposal.

10.0 Topic: Monthly Peak by Class
Reference: BCH 2007 Phase 1 RDA Decision, page 74

Table 3-4
Contribution to Monthly Peak by Class



Source: Exhibit B-3, Terasen 1.9.1

10.1 Please reproduce the graph from page 74 of the BCH 2007 Phase 1 RDA Decision using the most recent data from F2015 for the monthly peak by class.

10.1.1 To the extent that the shape of the graph has changed, please explain the factors that contribute to this change.

1.0 Topic: F2016 Cost of Service Study and Methodology

Reference: Chapter 3, Table 3-6, Page 3-36; BCUC IR 1.17.1

Table 3-6 R/C Ratios

	R/C Ratios		
	Final F2016 COS Study results		F2013 Fully Allocated COS
Rate Class	Final Study filed in the RDA (%)	Draft F2016 COS study posted to RDA website in February 2015 (%)	Filed on February 8, 2014 with the Commission (using 2007 RDA decision) (%)
COLUMN	A	B	C
Residential	93.9	93.9	89.8
SGS	112	112	126.7
MGS	117.1	120.5	120.8
LGS	100.9	99.7	102.1
Irrigation	85.1	85.2	86.6
Street Lighting	134.1	134.1	115.7
Transmission	101.4	101.5	104.4
Total Classes	100	100	

1.1.1 Please reproduce Table 3-6 with an additional column (i.e. Column (D)) that provides the R/C ratios for F2016 using the same 2007 RDA COS allocation methodologies that generate the results in Column C for F2013.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 1.29.1.

2.0 Topic: F2016 Cost of Service Study and Methodology

Reference: Chapter 3, Table 3-1, Page 3-10; Table 3-6, Page 3-36

Table 3-1 provides descriptions of the COS allocation methodology changes that BC Hydro has adopted in its F2016 COS study relative to the corresponding 2007 RDA decision COS allocation determinations.

1.2.1 Please complete the table below. For column (2), please provide the R/C ratios for F2016 using the methodologies approved in the 2007 RDA decision (i.e. the additional column requested in question 2.1) and for the next five columns (columns (3) – (7)), please provide the incremental percentage impact on the R/C ratios from sequentially introducing each of the five methodology changes set out in Table 3-1. For column (8), please provide a summation of column (2) and the incremental percentages from each of the five methodology changes set out in Table 3-1.

	Revenue to Cost (R/C) Ratios (%)							
		Incremental Effects of Table 3-1 COS Methodology Changes						
Rate Class	F2016 R/C Ratios using 2007 RDA	DSM 90% Gen / 5% Trans / 5% Dist	Heritage supply 55% energy / 45% demand	IPP costs 93% energy / 7% demand	Sub-function alize the Distribut ion system:	Classify cust care costs 100% cust	Sum of Column (2) through (7)	Final Study filed in the RDA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Illustrative Example[1]	93.2	0.3	0.9	0.5	1.2	1.1	97.2	97.5
Residential	91.7							93.9
SGS	118.3							112.0
MGS	120.9							117.1
LGS	99.4							100.9
Irrigation	92.9							85.1
Street Lighting	126.5							134.1
Transmission	105.4							101.4
Total Classes	100.0							100.0

[1] This example is for illustrative purposes only to demonstrate the intent of the question and is not based on evidence provided in this Application

RESPONSE:

The requested information has been populated in the table below.

Please note that Table 3-1 of Exhibit B-1 describes COS study-related directives from the 2007 RDA Decision, which is not a complete list of the changes proposed in the 2015 RDA. The table below is therefore not comprehensive in including all the changes proposed to the COS study for F2016. The remaining proposed changes to the F2016 COS study that were excluded from the table are:

- **Functionalization of IT costs as described in section 3.6.5.1 of Exhibit B-1;**
- **Functionalization of IPP capital lease costs as described in section 3.5.2;**
- **Functionalization of ERP costs to Generation (previously to Customer Care);**
- **Functionalization of Corporate Tax & Depreciation to include functionalization to Transmission (previously excluded because of separation of BCTC);**
- **Functionalization of Regulatory Accounts as described in section 3.6.7;**
- **Classification of SMI-related costs as described in section 3.7.8;**
- **Allocation of Generation and Transmission demand-related costs as described in section 3.8.3;**
- **Allocation of Distribution demand-related costs as described in section 3.8.4; and**
- **Allocation of metering costs as described in the Workshop 4 consideration memo at page 100 of 205, Appendix C-2B of Exhibit B-1.**

Further, an additional column was inserted (column 8a) to reflect the compounded effect some of the methodology changes have on R/C ratios in interacting with each other. For example, the proposed functionalization of DSM costs shifts a portion of Generation costs to Distribution which is then classified and allocated according to the sub-functionalization method described in Table 3-1 of Exhibit B-1.

R/C Ratios (%)									
Incremental Effects of Table 3-1 COS Methodology Changes									
Rate Class	F2016 R/C Ratios using 2007 RDA Decision	DSM 90% Gen/ 5% Trans/ 5% Dist	Heritage Supply 55% Energy/ 45% Demand	IPP Costs 93% Energy/ 7% Demand	Sub-functionalize the Distribution System:	Classify Cust Care Costs 100% Cust	Sum of Column (2) through (7)	Compound Effect of Methodology Changes in Columns (3) through (7)	Final F2016 COS Study Filed in the RDA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(8a)	(9)
Residential	91.7	-0.1	0.8	-0.3	1.9	-1.1	92.9	92.8	93.9
SGS	118.3	-0.1	0.0	0.0	-3.6	0.4	115.0	115.1	112.0
MGS	120.9	0.0	0.1	0.0	-6.2	2.5	117.3	117.0	117.1
LGS	99.4	0.0	-0.5	0.2	-1.7	2.5	99.9	99.9	100.9
Irrigation	92.9	-0.3	-3.3	1.6	-7.5	5.1	88.5	87.6	85.1
Street Lighting	126.5	0.0	1.7	-0.7	-3.5	-1.0	123.0	122.8	134.1
Transmission	105.4	0.2	-1.7	0.8	0.0	-0.2	104.5	104.4	101.4
Total Classes	100.0								100.0

2.0 Topic: F2016 Cost of Service Study and Methodology

Reference: Chapter 3, Table 3-1, Page 3-10; Table 3-6, Page 3-36

Table 3-1 provides descriptions of the COS allocation methodology changes that BC Hydro has adopted in its F2016 COS study relative to the corresponding 2007 RDA decision COS allocation determinations.

1.2.1.1 Please provide an explanation of the differences if the results of the summation in column (8) are different from the Final Study F2016 R/C ratios identified in first column of Table 3-6 (reproduced in column (9) above).

RESPONSE:

Please refer to BC Hydro's response to FortisBC IR 1.2.1.

3.0 Topic: Rate Class Segmentation, MGS and LGS Breakpoint

Reference: Chapter 4, Figure 4-2, Page 4-11

On page 4-11 BCH states that "it is difficult to pinpoint a clear breakpoint in the downward trend of unit costs".

1.3.1 Please confirm that a clear breakpoint between MGS and LGS cannot be identified with disaggregated data.

RESPONSE:

As described on page 4-11 of Exhibit B-1, the analysis revealed a downward trend in unit costs per kW for MGS and LGS customers; however, the results did not point to a single breakpoint where the rate of decline of unit costs changed definitively.

4.0 Topic: Rate Class Segmentation, Transmission Service Rate Class

Reference: Chapter 4, Table 4-4 and Attachment C-3B, Slide 28

In Table 4-4 on Page 4-21, BCH states that "the differential between an individual customer's R/C ratio and the Transmission Service rate class average is greater for some customers (#12 and #13 on Slide 40) than it is for these two utilities".

1.4.1 Please confirm that, relative to the class averages, there are differences in load characteristics seen for other customers within the Transmission rate classes (i.e. customers other than FortisBC and New Westminster).

RESPONSE:

Confirmed, however FortisBC and New Westminster are the only large customers in the Transmission Service rate class with high coincidence factors and low load factors. Refer to Figure 7 in the Workshop 5 consideration memo found at Appendix C-5A of Exhibit B-1, page 137 of 292.

4.0 Topic: Rate Class Segmentation, Transmission Service Rate Class

Reference: Chapter 4, Table 4-4 and Attachment C-3B, Slide 28

In Table 4-4 on Page 4-21, BCH states that "the differential between an individual customer's R/C ratio and the Transmission Service rate class average is greater for some customers (#12 and #13 on Slide 40) than it is for these two utilities".

1.4.1.1 As shown on Slide 39 of Attachment C-1B, there are a number of customers that have a higher than average coincidence factor as compared to the Transmission Service Rate class average (as provided in Table 4-3) or a lower load factor as compared to the class average or FortisBC and New Westminster. Please explain why BCH has not proposed changes for these customers similar to the change proposed for FortisBC and New Westminster?

RESPONSE:

Please refer to BC Hydro's response to FortisBC IR 1.4.1.

5.0 Topic: Rate Class Segmentation, Transmission Service Rate Class and F2016 Cost of Service Study

Reference: Chapter 4, Page 4-19, row 11 to 14.

BC Hydro used F2014 hourly load data for each Transmission customer to assign F2016 costs to individual customers on a pro rata basis using common allocators from the F2016 COS study

1.5.1 Please provide a detailed breakdown of the cost allocation in a comparable format to Schedule 4.1 of Appendix C-2C. Please also include a summary of which common allocators were used.

RESPONSE:

BC Hydro considers individual Transmission Service customer cost data to be confidential because it is financial and technical information that has consistently been treated as confidential by BC Hydro as such information could be used to estimate customer loads. To be responsive to this IR, the requested table sums the individual customer costs by major industry within the Transmission Service rate class.

BC Hydro considers individual customer cost allocations to be indicative of general trends.

Summary of Costs ($million)	Generation Energy-Related	Generation Demand-Related (4CP)	Transmission Demand-Costs (4CP)	% of costs that are Demand-related (%)
Pulp and Paper	165	38	35	31
Wood Products	38	11	10	36
Chemicals	53	14	13	35
Oil and Gas	27	7	6	33
Mining	121	32	29	34
Terminal	7	2	2	37
Other	35	8	8	32
New West	16	6	6	43
FortisBC	17	9	8	51

5.0 Topic: Rate Class Segmentation, Transmission Service Rate Class and F2016 Cost of Service Study

Reference: Chapter 4, Page 4-19, row 11 to 14.

BC Hydro used F2014 hourly load data for each Transmission customer to assign F2016 costs to individual customers on a pro rata basis using common allocators from the F2016 COS study

1.5.2 Please provide the estimated range of R/C ratios for all of the more than 100 customers in the Transmission Service Rate Class whose individual R/C ratio was estimated and used in the Individual Customer R/C ratio analysis (see page 4-19, lines 10-19). Please provide this by number of customers in increments of 5% as demonstrated in the table below:

R/C Ratio Range	Number of Customers
70% to 75%%	0
75% to 80%	1
80% to 85%	1
Etc.	

RESPONSE:

The requested distribution of estimated R/C ratios is below. The total F2014 energy purchases of Transmission Service customers in each R/C ratio range are also included. Generally, R/C ratios further away from the class average of ~101 per cent are associated with smaller Transmission Service customers.

BC Hydro considers individual customer cost allocations to be indicative of general trends and not as accurate as those aggregated by rate class in the F2016 COS study. Therefore, the R/C ratios below should be considered to be high level estimates.

R/C Ratio Range	Number of Customers
< 75%	**8**
75% to 80%	**0**
80% to 85%	**4**
85% to 90%	**14**

R/C Ratio Range	Number of Customers
90% to 95%	28
95% to 100%	17
100% to 105%	15
105% to 110%	6
110% to 115%	8
115% to 120%	5
120% to 125%	2
125% to 130%	0
130% to 135%	1
135% to 140%	0
140% to 145%	1
145% to 150%	2
150% to 155%	3
155% to 160%	1
160% to 165%	1
165% to 170%	0
>170%	15

6.0 Topic: Residential Inclining Block

Reference: Chapter 5, Page 5-42 and Attachment C-3B, Slide 28

On page 5-42 Saskpower is identified as having the lowest percentage (at 22%) of allocated fixed costs recovered by the residential basic charge and this is presented as a comparator with BC Hydro's basic charge recovering 45% of allocated fixed costs, yet at $20.22/month for City customers and $29.22/month for rural customers, the Saskpower residential basic charge is roughly 4 to 6 times BC Hydro's residential basic charge of $5/month.

1.6.1 Please confirm that based on the information provided in Attachment C-3B, Slide 28, the calculated value for the annual fixed cost allocation for Saskpower residential customers is in the range of $1,103 / year ($20.22 per month City x 12 months per year /22%) to $1,592/year ($29.19 per month Rural x 12 months per year / 22%) and for BC Hydro residential customers is approximately $133 per year ($5 per month x 12 months per year / 45%).

RESPONSE:

Confirmed.

6.0 Topic: Residential Inclining Block

Reference: Chapter 5, Page 5-42 and Attachment C-3B, Slide 28

On page 5-42 Saskpower is identified as having the lowest percentage (at 22%) of allocated fixed costs recovered by the residential basic charge and this is presented as a comparator with BC Hydro's basic charge recovering 45% of allocated fixed costs, yet at $20.22/month for City customers and $29.22/month for rural customers, the Saskpower residential basic charge is roughly 4 to 6 times BC Hydro's residential basic charge of $5/month.

1.6.2 Please list the key factors and differences in cost allocation approach that explain why Saskpower's allocated fixed costs per customer per year for residential customers are roughly 8 to 12 times as large as BC Hydro's.

RESPONSE:

BC Hydro notes that the SaskPower basic charge recovers 22 per cent of SaskPower's residential customer-related costs in contrast to the RIB rate basic charge which recovers about 45 per cent of Residential customer-related cost. Accordingly, BC Hydro does not agree with the assertion in the IR that the absolute level ($) of the SaskPower basic charge is relevant for comparison purposes. Given the limited to no relevance of the request comparison, BC Hydro respectively declines to respond to the request in the IR that BC Hydro provide a breakdown of SaskPower's basic charge-related cost allocation, but notes that the two utilities have different services areas in terms of geography and customer dispersion.

6.0 Topic: Residential Inclining Block

Reference: Chapter 5, Page 5-42 and Attachment C-3B, Slide 28

On page 5-42 Saskpower is identified as having the lowest percentage (at 22%) of allocated fixed costs recovered by the residential basic charge and this is presented as a comparator with BC Hydro's basic charge recovering 45% of allocated fixed costs, yet at $20.22/month for City customers and $29.22/month for rural customers, the Saskpower residential basic charge is roughly 4 to 6 times BC Hydro's residential basic charge of $5/month.

1.6.3 Please confirm that all of the residential basic charges presented in the Canadian jurisdiction survey (Appendix C-3B, Slide 28) are between 2 and 6 times the level of BC Hydro's RIB basic charge (with the exception of Manitoba Hydro's residential basic charge for <200 Amp. Service, which is about 1.5 times the RIB basic charge).

RESPONSE:

BC Hydro submits that the absolute level ($) of the various surveyed Canadian electric utility basic charges is not relevant for comparison purposes. Please refer to BC Hydro's response to FortisBC IR 1.6.2. BC Hydro further notes that the RIB rate basic charge customer-related cost recovery is in alignment with surveyed Canadian electric utilities.

7.0 Topic: Residential Inclining Block

Reference: Chapter 5, Page 5-42 and Attachment C-3B, Slide 28

"The current RIB rate basic charge recovery of 45 per cent is in the range of Canadian electric utility residential rate basic charge cost recovery but at the lower end of the range". Figure 5-18 which depicts BC Hydro's requested RIB pricing approach and shows the RIB Step 2 rate as exceeding the upper limit of the Energy LRMC.

1.7.1 Has BC Hydro considered making a one-time shift in RIB revenue recovery from the Step 2 rate to the basic charge, followed by adopting BC Hydro's proposed rate change approach (see Application, p.5-33) of applying the yearly approved revenue requirement increases to each of the RIB rate components?

RESPONSE:

It is unclear from the question what is specifically defined as a "one-time shift in RIB revenue recovery from the Step 2 rate to the basic charge", but BC Hydro interprets the suggestion as an one-time increase in the RIB rate basic charge and an offsetting decrease to the Step 2 rate, holding the Step 1 rate constant, to maintain revenue neutrality.

BC Hydro has not considered such a one-time shift. At RDA Workshop 3 BC Hydro reviewed its modeling approach and evaluation of possible increases to the RIB rate basic charge to recover alternatively 50 per cent and 100 per cent of assigned customer-related costs (please refer to the Workshop 3 presentation material at Appendix C-3A of Exhibit B-1, pages 67 to 79 of 184):

- **BC Hydro's approach was to hold the Step 2 rate constant and to residually calculate the Step 1 rate to maintain revenue neutrality for the reason that the resulting lower Step 1 rate would allow the additional basic charge revenue to be distributed to the benefit of all Residential customers;**

- **BC Hydro reviewed that an increase in the Basic Charge to 100 per cent recovery of customer-related costs would improve fairness in aligning cost recovery with cost causation but would impose high bill impacts on typical customers, including low income. BC Hydro notes that organizations representing segments of its Residential class (BCSEA, BCOAPO) opposed an increase to the RIB rate basic charge. Commission staff observed that such and increase would adversely affect low income customers. Please refer to section 3.3.1 of the Workshop 3 consideration memo (Exhibit B-1, Appendix 3-CA, pages 112-113 of 184); and**

- **As noted in BC Hydro's response to FortisBC IR 1.6.3, the RIB rate basic charge recovery of customer-related costs in align with surveyed Canadian electric utilities including FortisBC.**

7.0 Topic: Residential Inclining Block

Reference: Chapter 5, Page 5-42 and Attachment C-3B, Slide 28

"The current RIB rate basic charge recovery of 45 per cent is in the range of Canadian electric utility residential rate basic charge cost recovery but at the lower end of the range". Figure 5-18 which depicts BC Hydro's requested RIB pricing approach and shows the RIB Step 2 rate as exceeding the upper limit of the Energy LRMC.

1.7.1.1 Does BC Hydro agree that such a one-time shift could be used to bring the Step 2 rate within the LRMC range while at the same time increasing the RIB basic charge and related revenue recovery to a level more typical for Canadian electric utilities?

RESPONSE:

No, BC Hydro does not agree with the assertion in this IR. As set out in BC Hydro's responses to FortisBC IRs 1.6.3 and 1.7.1, the RIB rate basic charge recovery of customer-related costs aligns with the percentage cost recovery of surveyed Canadian electric utilities, including FortisBC. The RIB rate basic charge is typical for Canadian electric utilities in its recovery of customer-related costs.

To be responsive BC Hydro offers the following:

- **An increase in the RIB rate basic charge of $4.00 per month in F2016, as requested in FortisBC IR 1.7.1.3, would increase the monthly basic charge by about 75.6 per cent, from $5.29 to $9.29 (based on a 30-day month). As a result, this would increase the amount of customer customer-related cost recovery from the current 45 per cent to about 79 per cent. This would be greater than any Canadian electric utility surveyed with New Brunswick Power being the only exception;**

- **An increase in the RIB rate basic charge of $4.00 per month would have unacceptable bill impacts, as shown in BC Hydro's response, to FortisBC IRs 1.7.1.3 and 1.7.1.3.1. This is due to the basic charge representing a substantial component of the bill for many customers, especially low consuming ones. A small increase in the basic charge without a subsequent reduction in the RIB Step 1 rate present bill impacts. For example, for the median apartment customer at about 4,000 KWh/year, the F2016 basic charge is 17 per cent of the annual bill. Increasing the basic charge by $4 per month without a subsequent reduction in the RIB Step 1 rate will increase the basic charge proportion to 26 per cent of the bill, and a resulting bill increase of 13 per cent over the status quo RIB rate bill.**

7.0 Topic: Residential Inclining Block

Reference: Chapter 5, Page 5-42 and Attachment C-3B, Slide 28

"The current RIB rate basic charge recovery of 45 per cent is in the range of Canadian electric utility residential rate basic charge cost recovery but at the lower end of the range". Figure 5-18 which depicts BC Hydro's requested RIB pricing approach and shows the RIB Step 2 rate as exceeding the upper limit of the Energy LRMC.

1.7.1.2 How much cost shifting of this nature could be done without causing unacceptable rate impacts for customers in particular sub-segments of the residential class?

RESPONSE:

As described in BC Hydro response to FortisBC IR 1.7.1.1, the basic charge component of the RIB rate represents a large component of the bill for low consuming customers and even a small increase in the basic charge without a subsequent reduction in the Step 1 rate will present unacceptable bill impacts. For example, BC Hydro's responses to FortisBC IRs 1.7.1.3 and 1.7.1.3.1 show that even a small increase in the basic charge of $2/month without a subsequent reduction in the Step 1 rate will likely cause 40 per cent of customers will to experience bill impacts greater than 10 per cent.

As discussed in section 3.3.2 of Workshop 3 consideration memo at Appendix C-3A of Exhibit B-1, BC Hydro expressed its concern with increasing the amount of cost recovery through the basic charge due to the impact on low consuming customers, including apartments and some low income customers. Organizations representing Residential sectors (BCOAPO, BCSEA) share BC Hydro's concern.

7.0 Topic: Residential Inclining Block

Reference: Chapter 5, Page 5-42 and Attachment C-3B, Slide 28

"The current RIB rate basic charge recovery of 45 per cent is in the range of Canadian electric utility residential rate basic charge cost recovery but at the lower end of the range". Figure 5-18 which depicts BC Hydro's requested RIB pricing approach and shows the RIB Step 2 rate as exceeding the upper limit of the Energy LRMC.

1.7.1.3 Please provide rate impact analyses of one-time RIB revenue recovery shifts from the Step 2 rate to the basic charge which increase the basic charge by (i) $2.00/month, and (ii) $4.00/month. Assume in both cases that, other than the one-time revenue shift, BC Hydro's proposed rate change approach of applying the approved revenue requirement increases to each of the RIB rate components applies for F2017 to F2019.

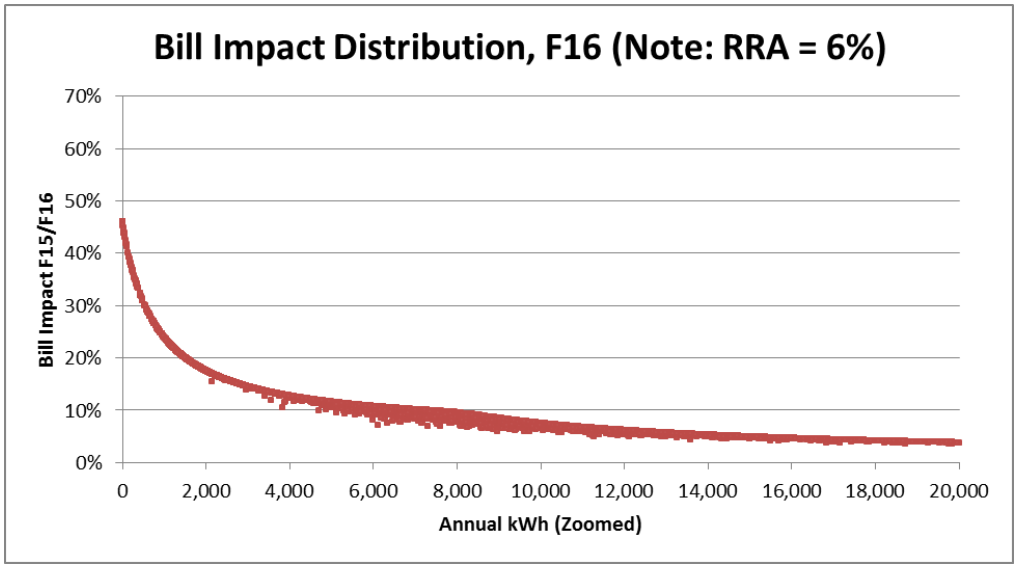
RESPONSE:

Using the same vintage of modelling parameters and simulation year of rate change (F2016) as in Workshop 3 (Exhibit B-1, Appendix C-3A, page 69), the illustrative rates and bill impact distributions are as follows:

<u>Model (i)</u>

RIB rate Step 1 at the F2016 status quo rate of 7.97 cents/kWh;
Step 2 to recover the remaining F2016 revenue at 11.37 cents/kWh;
Basic charge set to $0.2431/day, about $2 more per month.

All rate components will increase by RRA increases for subsequent years (F2017 and F2018).

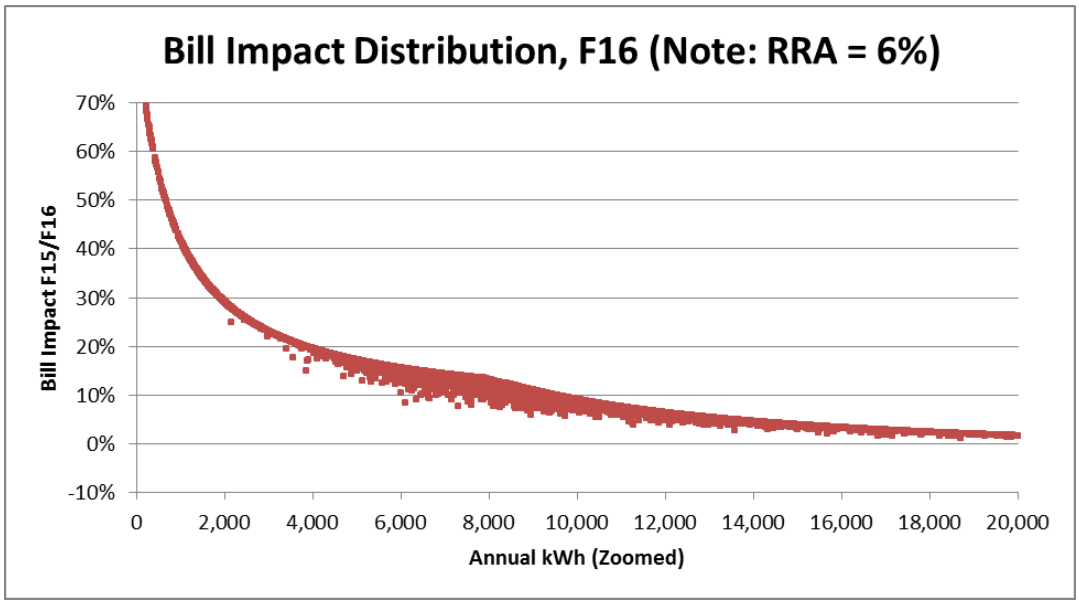


Bill impacts of subsequent years (F2017 and F2018) will be RRA.

<u>Model (ii)</u>

RIB rate Step 1 at the F2016 status quo rate of 7.97 cents/kWh;
Step 2 to recover the remaining F2016 revenue at 10.80 cents/kWh;
Basic charge set to $0.3097/day, about $4 more per month.

All rate components will increase by RRA increases for subsequent years (F2017 and F2018)



Bill impacts of subsequent years (F2017 and F2018) will be RRA increases.

7.0 Topic: Residential Inclining Block

Reference: Chapter 5, Page 5-42 and Attachment C-3B, Slide 28

"The current RIB rate basic charge recovery of 45 per cent is in the range of Canadian electric utility residential rate basic charge cost recovery but at the lower end of the range". Figure 5-18 which depicts BC Hydro's requested RIB pricing approach and shows the RIB Step 2 rate as exceeding the upper limit of the Energy LRMC.

1.7.1.3.1 Relative to BC Hydro's proposed approach without any intra-class revenue shifting, please explain which residential sub-segments are most affected by the one-time revenue shift to the basic charge, and provide a summary of the bill impacts on the most-affected sub-segments in both percentage terms and annual dollar amounts.

RESPONSE:

Bill impacts depend on energy consumption, regardless of customer segments.

Given the modelling assumptions in BC Hydro's response to FortisBC IR 1.7.1.3:

- **If the basic charge is to be increased by $2/month, customers with annual consumption of approximately 8,000 kWh/year or less will likely experience bill impacts greater than 10 per cent. This represents about 40 per cent of Residential customers; and**

- **If the basic charge is to be increased by $4/month, customers with annual consumption of approximately 9,700 kWh/year or less will likely experience bill impacts greater than 10 per cent. This represents over 54 per cent of Residential customers.**

The illustrative bill impacts at a range of consumption levels that encompass Residential typical customers, regardless of segment, are as follows:

kWh/year	A (F2016 Model (i) Bill) ($)	B (F2016 Model (ii) Bill) ($)	C (F2015 Bill) ($)	Bill Impact Model (i) (A/C-1) (%)	Bill Impact Model (ii) (B/C-1) (%)
1000	177	202	143	24	42
2000	261	286	222	18	29
3000	344	370	301	14	23
4000	428	453	380	13	19

kWh/year	A (F2016 Model (i) Bill) ($)	B (F2016 Model (ii) Bill) ($)	C (F2015 Bill) ($)	Bill Impact Model (i) (A/C-1) (%)	Bill Impact Model (ii) (B/C-1) (%)
5000	512	537	459	12	17
6000	595	621	538	11	15
7000	679	704	616	10	14
8000 (~Median)	763	788	695	10	13
9000	878	899	810	8	11
10000	998	1,012	928	8	9
11000	1,117	1,125	1,047	7	8
12000	1,237	1,239	1,165	6	6
13000	1,356	1,352	1,283	6	5
14000	1,475	1,466	1,402	5	5
15000	1,595	1,579	1,520	5	4
16000	1,714	1,692	1,638	5	3
17000	1,834	1,806	1,757	4	3
18000	1,953	1,919	1,875	4	2
19000	2,072	2,033	1,993	4	2
20000	2,192	2,146	2,112	4	2

8.0 Topic: General Service

Reference: Chapter 6

1.8.1 Please provide a bill frequency analysis, in a table format, for SGS, MGS & LGS. For SGS, please show the number of customers in blocks of annual consumption of 5,000 kWh; for MGS, please show the number of customers in blocks 25 kW to 175 kW and increments 5,000 kWh to 600,000 kWh; and for LGS, please show the number of customers in blocks of 25kW starting from 125kW to 500kW, corresponding to increments 10,000 kWh starting from 350,000 kWh to 1,000,000 kWh.

RESPONSE:

The distributions are provided as percentages of the SGS population, given the active accounts in F2015.

Small General Service, F2015	
kWh Bucket (5,000 kWh)	**(%)**
5,000	**26.67**
10,000	**16.36**
15,000	**12.02**
20,000	**8.71**
25,000	**6.31**
30,000	**4.83**
35,000	**3.86**
40,000	**3.08**
45,000	**2.5**
50,000	**2.05**
55,000	**1.79**
60,000	**1.58**
65,000	**1.4**
70,000	**1.17**
75,000	**1.06**
80,000	**0.89**
85,000	**0.75**
90,000	**0.68**
95,000	**0.59**

Small General Service, F2015	
kWh Bucket (5,000 kWh)	**(%)**
100,000	**0.49**
105,000	**0.43**
110,000	**0.39**
115,000	**0.31**
120,000	**0.28**
125,000	**0.24**
130,000	**0.21**
135,000	**0.19**
140,000	**0.16**
145,000	**0.13**
150,000	**0.1**
155,000	**0.1**
160,000	**0.09**
165,000	**0.08**
170,000	**0.07**
175,000	**0.07**
180,000	**0.05**
185,000	**0.04**
>185,000	**0.24**

For MGS and LGS, please refer to Attachment 1 for this response.

Medisum General Service, F2015										
		kW Bucket (25kW)								
Wh Bucket (5,000 kWh		25	50	75	100	125	150	175	>175	Total
5,000	Percent									
10,000	Percent	0.69	0.51	0.12	0.03	0.01	0	0	0	1.36
15,000	Percent	0.42	0.48	0.14	0.02	0.01	0.01	0	0	1.07
20,000	Percent	0.27	0.51	0.14	0.05	0.01	0.01	0.01	0	1.01
25,000	Percent	0.23	0.58	0.14	0.04	0.03	0.01	0.01	0.01	1.05
30,000	Percent	0.17	0.48	0.14	0.06	0.03	0.02	0	0	0.9
35,000	Percent	0.13	0.55	0.15	0.07	0.04	0	0	0.01	0.96
40,000	Percent	0.09	0.67	0.22	0.06	0.02	0.02	0	0.01	1.09
45,000	Percent	0.15	0.79	0.18	0.05	0.01	0.01	0.01	0.01	1.19
50,000	Percent	0.06	0.7	0.29	0.09	0.02	0.02	0.01	0.01	1.18
55,000	Percent	0.05	0.6	0.26	0.09	0.02	0.01	0.02	0.01	1.05
60,000	Percent	0.05	0.82	0.29	0.07	0.03	0.01	0.01	0.01	1.28
65,000	Percent	0.02	0.69	0.33	0.11	0.02	0	0.01	0	1.18
70,000	Percent	0.02	0.82	0.33	0.11	0.02	0.01	0.01	0.01	1.32
75,000	Percent	0.02	0.74	0.35	0.08	0.05	0.02	0.01	0.02	1.28
80,000	Percent	0.01	0.89	0.26	0.09	0.03	0.02	0.01	0.01	1.33
85,000	Percent	0	0.97	0.4	0.11	0.03	0.02	0	0.01	1.54
90,000	Percent	0.01	1.05	0.47	0.15	0.01	0.02	0.01	0.01	1.73
95,000	Percent	0.01	0.97	0.43	0.09	0.05	0.02	0.01	0.02	1.58
100,000	Percent	0.01	1.11	0.56	0.19	0.02	0.02	0.02	0.01	1.95
105,000	Percent	0.03	1.03	0.54	0.13	0.06	0.01	0.01	0.01	1.82
110,000	Percent	0	1.09	0.53	0.1	0.06	0.02	0.02	0.01	1.83
115,000	Percent	0.01	1.03	0.48	0.12	0.06	0.02	0	0.01	1.73
120,000	Percent	0.01	1.05	0.64	0.11	0.03	0.01	0.01	0.01	1.87
125,000	Percent	0	1.06	0.65	0.18	0.05	0.02	0.01	0	1.95
130,000	Percent	0.01	1.06	0.67	0.14	0.07	0.02	0.01	0	1.98
135,000	Percent	0.01	1.02	0.66	0.16	0.04	0.03	0.01	0	1.93
140,000	Percent	0.01	0.95	0.73	0.21	0.03	0.04	0	0	1.97
145,000	Percent	0	0.96	0.79	0.14	0.06	0.02	0.01	0.01	1.99
150,000	Percent	0	0.9	0.73	0.18	0.05	0.03	0.01	0	1.9
155,000	Percent	0	0.8	0.75	0.19	0.07	0.02	0.01	0.01	1.85
160,000	Percent	0	0.67	0.66	0.19	0.05	0.01	0	0	1.58
165,000	Percent	0	0.69	0.77	0.26	0.09	0.01	0.01	0	1.81
170,000	Percent	0	0.74	0.76	0.2	0.06	0.02	0.01	0	1.79
175,000	Percent	0	0.54	0.73	0.25	0.05	0.02	0	0.01	1.59
180,000	Percent	0	0.62	0.84	0.28	0.04	0.03	0.01	0.01	1.83
185,000	Percent	0	0.53	0.72	0.23	0.05	0.01	0.01	0	1.55
190,000	Percent	0	0.62	0.68	0.23	0.1	0.02	0.01	0	1.66
195,000	Percent	0	0.48	0.69	0.23	0.06	0.03	0	0	1.49
200,000	Percent	0	0.51	0.58	0.29	0.09	0.03	0	0.01	1.5
205,000	Percent	0	0.45	0.47	0.19	0.13	0.02	0.01	0	1.27
210,000	Percent	0	0.41	0.67	0.3	0.06	0.02	0.01	0.01	1.47
215,000	Percent	0	0.31	0.53	0.22	0.1	0.02	0.01	0.01	1.21
220,000	Percent	0	0.46	0.61	0.28	0.06	0.03	0.01	0.01	1.46
225,000	Percent	0	0.35	0.77	0.3	0.06	0.03	0.01	0	1.51
230,000	Percent	0	0.25	0.65	0.24	0.1	0.01	0	0	1.25
235,000	Percent	0	0.24	0.5	0.28	0.14	0.01	0	0	1.17
240,000	Percent	0	0.26	0.56	0.22	0.12	0.02	0.01	0.01	1.19
245,000	Percent	0	0.18	0.48	0.23	0.08	0.01	0	0.01	0.98
250,000	Percent	0	0.16	0.49	0.25	0.11	0.03	0.02	0	1.05
255,000	Percent	0	0.21	0.5	0.27	0.06	0.05	0.02	0.01	1.12
260,000	Percent	0	0.15	0.44	0.22	0.1	0.03	0.01	0	0.94
265,000	Percent	0	0.22	0.39	0.29	0.08	0.02	0	0	0.99
270,000	Percent	0	0.14	0.36	0.24	0.09	0.03	0.02	0	0.87
275,000	Percent	0	0.09	0.45	0.26	0.14	0.01	0.01	0	0.97
280,000	Percent	0	0.09	0.43	0.25	0.09	0.03	0.01	0	0.9
285,000	Percent	0	0.11	0.36	0.22	0.07	0.02	0	0	0.78
290,000	Percent	0	0.08	0.34	0.2	0.13	0.04	0.02	0.01	0.82
295,000	Percent	0	0.1	0.39	0.21	0.07	0.02	0	0	0.79
300,000	Percent	0	0.06	0.39	0.23	0.13	0.05	0.01	0	0.86
305,000	Percent	0	0.1	0.25	0.2	0.1	0.06	0.01	0.01	0.73
310,000	Percent	0	0.05	0.34	0.25	0.09	0.04	0.01	0.01	0.79
315,000	Percent	0	0.06	0.24	0.24	0.12	0.02	0	0	0.68
320,000	Percent	0	0.05	0.31	0.22	0.06	0.04	0.01	0.01	0.69
325,000	Percent	0	0.03	0.25	0.27	0.07	0.05	0.01	0.01	0.69
330,000	Percent	0	0.05	0.22	0.19	0.09	0.04	0.02	0	0.61
335,000	Percent	0	0.02	0.29	0.17	0.09	0	0	0	0.57
340,000	Percent	0	0.01	0.26	0.28	0.07	0.03	0.01	0	0.67
345,000	Percent	0	0.01	0.2	0.17	0.08	0.05	0.01	0.01	0.52
350,000	Percent	0	0.01	0.22	0.22	0.13	0.03	0.02	0	0.62
355,000	Percent	0	0.01	0.13	0.18	0.11	0.06	0	0.01	0.5
360,000	Percent	0	0.01	0.22	0.15	0.13	0.06	0	0.01	0.57
365,000	Percent	0	0	0.14	0.18	0.1	0.02	0.03	0.01	0.47
370,000	Percent	0	0	0.13	0.17	0.07	0.06	0.03	0.01	0.46
375,000	Percent	0	0	0.17	0.17	0.14	0.03	0	0.01	0.51
380,000	Percent	0	0	0.17	0.18	0.13	0.02	0	0.01	0.5
385,000	Percent	0	0.01	0.14	0.22	0.11	0.01	0.01	0	0.5
390,000	Percent	0	0	0.11	0.13	0.12	0.05	0.02	0.01	0.43
395,000	Percent	0	0.01	0.11	0.11	0.08	0.03	0	0	0.34
400,000	Percent	0	0.01	0.14	0.11	0.05	0.01	0.01	0.01	0.34
405,000	Percent	0	0	0.1	0.14	0.11	0.03	0.01	0	0.4
410,000	Percent	0	0	0.09	0.18	0.09	0.02	0	0	0.38
415,000	Percent	0	0	0.05	0.14	0.1	0.04	0.01	0	0.33
420,000	Percent	0	0.01	0.09	0.2	0.08	0.05	0.01	0.01	0.44
425,000	Percent	0	0	0.07	0.12	0.08	0.02	0	0.01	0.3
430,000	Percent	0	0	0.03	0.11	0.07	0.02	0	0	0.23
435,000	Percent	0	0	0.03	0.12	0.09	0.04	0	0	0.28
440,000	Percent	0	0	0.04	0.04	0.11	0.01	0	0	0.19
445,000	Percent	0	0	0.04	0.11	0.06	0.04	0.01	0.02	0.29
450,000	Percent	0	0.01	0.05	0.13	0.05	0.02	0.01	0.01	0.27
455,000	Percent	0	0	0.02	0.07	0.05	0.02	0.01	0	0.18
460,000	Percent	0	0	0.02	0.08	0.06	0.02	0	0.01	0.19
465,000	Percent	0	0	0.02	0.09	0.05	0.03	0	0	0.18
470,000	Percent	0	0	0.01	0.1	0.09	0.02	0.01	0	0.23
475,000	Percent	0	0	0.01	0.09	0.09	0.04	0.01	0.01	0.25
480,000	Percent	0	0	0.01	0.09	0.08	0.03	0.01	0	0.21
485,000	Percent	0	0	0.02	0.05	0.06	0.03	0.01	0.01	0.18
490,000	Percent	0	0	0.01	0.09	0.05	0.04	0.01	0	0.19
495,000	Percent	0	0	0.01	0.06	0.07	0.03	0	0.01	0.18
500,000	Percent	0	0	0.03	0.06	0.05	0.02	0	0.01	0.17
505,000	Percent	0	0	0.01	0.05	0.05	0.02	0.01	0	0.14
510,000	Percent	0	0	0	0.05	0.06	0.02	0.02	0	0.14
515,000	Percent	0	0	0	0	0.03	0.01	0.02	0	0.06
520,000	Percent	0	0	0	0.02	0.01	0.04	0.01	0.01	0.1
525,000	Percent	0	0	0	0.06	0.03	0.02	0.01	0	0.12
530,000	Percent	0	0	0	0.01	0.03	0.03	0	0	0.08
535,000	Percent	0	0	0	0.02	0.02	0.01	0	0	0.05
540,000	Percent	0	0	0.01	0.03	0.02	0.01	0.01	0.01	0.07
545,000	Percent	0	0	0.01	0.01	0.01	0.01	0	0	0.04
550,000	Percent	0	0	0	0.01	0.01	0.01	0	0.01	0.04
555,000	Percent	0	0	0	0.01	0.01	0	0.01	0	0.02
560,000	Percent	0	0	0	0	0	0.01	0.01	0.01	0.03
565,000	Percent	0	0	0	0.01	0.01	0	0.01	0.01	0.02
570,000	Percent	0	0	0	0	0.01	0	0	0	0.01
575,000	Percent	0	0	0	0	0.01	0	0.01	0	0.02
580,000	Percent	0	0	0	0.01	0.01	0	0	0.01	0.02
585,000	Percent	0	0	0	0	0.01	0.01	0	0	0.01
590,000	Percent	0	0	0	0	0.01	0	0.01	0.01	0.02
595,000	Percent	0	0	0	0.01	0	0	0	0	0.01
600,000	Percent	0	0	0	0.01	0.01	0	0	0	0.01
>600,000	Percent	0	0	0	0.01	0.01	0.02	0.01	0.02	0.05
Total	Percent	3.6	35.28	33.47	16.44	7.29	2.64	0.78	0.5	100

Large General Service, F2015

kWh Bucket (10,000 kWh)		kW Bucket (25kW) <100	125	150	175	200	225	250	275	300	325	350	375	400	425	450	475	500	>500	Total
<340,000	Percent																			
350,000	Percent	0.06	0.1	0.1	0.06	0.11	0.06	0.04	0.03	0.01	0	0.03	0	0.01	0	0	0.01	0.01	0	0.64
360,000	Percent	0.03	0.04	0.17	0.1	0.07	0.04	0.03	0	0.03	0.04	0	0	0	0.01	0	0	0	0.01	0.58
370,000	Percent	0.01	0.07	0.1	0.08	0.03	0.04	0.03	0.01	0.01	0	0	0.01	0	0	0	0.01	0	0	0.42
380,000	Percent	0.01	0.1	0.16	0.07	0.07	0.04	0.04	0.04	0.01	0	0	0.01	0	0	0.01	0	0	0	0.58
390,000	Percent	0.01	0.11	0.11	0.1	0.08	0.04	0.01	0.01	0.03	0.03	0	0.01	0	0	0	0.01	0	0	0.58
400,000	Percent	0.03	0.06	0.13	0.1	0.1	0.04	0.04	0.01	0.01	0.01	0	0	0	0	0	0	0	0	0.54
410,000	Percent	0.07	0.2	0.24	0.07	0.07	0.01	0.01	0.03	0.03	0.03	0	0	0.01	0	0	0	0	0.01	0.79
420,000	Percent	0.11	0.11	0.13	0.17	0.1	0.07	0.04	0	0	0.01	0	0.01	0.01	0.01	0	0	0	0	0.79
430,000	Percent	0.11	0.08	0.14	0.14	0.14	0.07	0	0.03	0	0	0	0	0	0	0	0.01	0	0	0.73
440,000	Percent	0.14	0.08	0.07	0.11	0.01	0.03	0.03	0.04	0.03	0.01	0.01	0	0.01	0.01	0	0	0	0.03	0.64
450,000	Percent	0.03	0.07	0.11	0.14	0.07	0.04	0.03	0	0.01	0	0	0.03	0	0	0	0	0	0	0.54
460,000	Percent	0.06	0.11	0.18	0.08	0.08	0.07	0.04	0	0.01	0	0	0	0	0	0	0	0.01	0.01	0.68
470,000	Percent	0.07	0.16	0.11	0.17	0.11	0.06	0.04	0.01	0	0	0.03	0.01	0	0	0	0	0	0	0.78
480,000	Percent	0.07	0.16	0.16	0.13	0.1	0.07	0.03	0.03	0	0.01	0.04	0.01	0	0	0	0	0.01	0	0.82
490,000	Percent	0.13	0.16	0.11	0.17	0.1	0.06	0.01	0.01	0.03	0.03	0	0	0	0	0	0	0	0.01	0.82
500,000	Percent	0.14	0.23	0.18	0.11	0.11	0.04	0.01	0.04	0.01	0.03	0.03	0.03	0	0.04	0.01	0	0	0	1.03
510,000	Percent	0.13	0.17	0.23	0.21	0.11	0.1	0.06	0.04	0.03	0.01	0.01	0	0	0.01	0	0	0	0	1.12
520,000	Percent	0.16	0.18	0.18	0.14	0.07	0.06	0.06	0.03	0.04	0.01	0	0	0	0	0	0	0	0	0.93
530,000	Percent	0.21	0.16	0.21	0.13	0.03	0.11	0.03	0.01	0	0	0	0	0.01	0	0.01	0	0	0.01	0.93
540,000	Percent	0.18	0.3	0.2	0.2	0.06	0.06	0.06	0.04	0.01	0.01	0.01	0	0.01	0	0	0	0	0.01	1.16
550,000	Percent	0.2	0.28	0.2	0.16	0.13	0.08	0.04	0.01	0	0.03	0.01	0	0.03	0	0	0	0	0	1.17
560,000	Percent	0.16	0.17	0.31	0.13	0.08	0.03	0.08	0.04	0	0.03	0	0.01	0	0	0.01	0	0	0	1.06
570,000	Percent	0.11	0.21	0.18	0.17	0.13	0.06	0.06	0.01	0	0.01	0.01	0.01	0.03	0	0	0	0	0	1
580,000	Percent	0.11	0.28	0.21	0.16	0.08	0.07	0.06	0.03	0.03	0.01	0.03	0.01	0	0	0	0	0	0.03	1.12
590,000	Percent	0.16	0.21	0.27	0.2	0.07	0.1	0.06	0.06	0	0.01	0.01	0.01	0	0	0	0	0	0	1.16
600,000	Percent	0.1	0.16	0.23	0.27	0.2	0.07	0.06	0.01	0.03	0	0.01	0.03	0.01	0	0.01	0.01	0.01	0.04	1.26
610,000	Percent	0.16	0.17	0.23	0.14	0.11	0.04	0.06	0.03	0.01	0.03	0	0.01	0	0	0.01	0.01	0	0.01	1.03
620,000	Percent	0.06	0.23	0.17	0.2	0.13	0.07	0.03	0.04	0.03	0.01	0.03	0.01	0	0	0.01	0	0	0.04	1.06
630,000	Percent	0.1	0.23	0.18	0.11	0.16	0.08	0.04	0.03	0	0.04	0.03	0	0	0	0	0	0	0	1
640,000	Percent	0.06	0.21	0.14	0.17	0.08	0.07	0.07	0.08	0.03	0	0.07	0	0.01	0	0	0	0	0.01	1.02
650,000	Percent	0.04	0.21	0.2	0.13	0.04	0.07	0.04	0.06	0.03	0	0.01	0	0	0	0	0	0	0.01	0.85
660,000	Percent	0.01	0.16	0.13	0.13	0.13	0.07	0.04	0.03	0.03	0.03	0	0.03	0.01	0.03	0	0.01	0.01	0.01	0.86
670,000	Percent	0.01	0.08	0.24	0.16	0.08	0.07	0.03	0.03	0.01	0.03	0	0.03	0	0.01	0	0	0	0.01	0.81
680,000	Percent	0.03	0.11	0.17	0.11	0.14	0.11	0.1	0.04	0.01	0.01	0	0.01	0.01	0	0.01	0.01	0	0.01	0.92
690,000	Percent	0.03	0.2	0.11	0.17	0.13	0.14	0.06	0.01	0	0.03	0.01	0.01	0	0	0	0	0	0	0.9
700,000	Percent	0	0.13	0.18	0.16	0.1	0.08	0.01	0	0.04	0	0.01	0.01	0	0	0.01	0.01	0.03	0	0.79
710,000	Percent	0	0.08	0.1	0.18	0.18	0.08	0.06	0.01	0.03	0.01	0	0	0.01	0.01	0	0.01	0.03	0.03	0.85
720,000	Percent	0	0.1	0.11	0.17	0.11	0.04	0.03	0.03	0.01	0	0.01	0	0	0	0	0	0	0.01	0.64
730,000	Percent	0	0.07	0.07	0.13	0.1	0.06	0	0.07	0.04	0.01	0.01	0.01	0	0	0	0	0	0.01	0.59
740,000	Percent	0	0.07	0.17	0.1	0.13	0.11	0.06	0.01	0.04	0.04	0.04	0	0	0.01	0	0	0	0.04	0.83
750,000	Percent	0	0.06	0.1	0.1	0.11	0.1	0.04	0	0.03	0.01	0.03	0	0	0	0	0	0	0.03	0.61
760,000	Percent	0	0.13	0.2	0.16	0.1	0.16	0.01	0.04	0.03	0.01	0	0.03	0	0	0	0	0.03	0	0.89
770,000	Percent	0	0.07	0.11	0.07	0.07	0.08	0.03	0.07	0	0	0	0.01	0	0	0	0.01	0	0.04	0.58
780,000	Percent	0	0.03	0.16	0.08	0.18	0.07	0.03	0.04	0.03	0.03	0.01	0.01	0	0	0	0	0	0.01	0.69
790,000	Percent	0	0.07	0.13	0.1	0.06	0.08	0.06	0.07	0.03	0.01	0.03	0	0.01	0	0	0	0	0	0.65
800,000	Percent	0	0.01	0.08	0.11	0.07	0.08	0.01	0.04	0.07	0.03	0.01	0.03	0.01	0	0.03	0.01	0.03	0	0.65
810,000	Percent	0	0.04	0.07	0.21	0.07	0.08	0.03	0.06	0.03	0.03	0	0.01	0	0	0	0	0	0.04	0.68
820,000	Percent	0	0.03	0.04	0.16	0.08	0.07	0.03	0.04	0.06	0	0	0.04	0	0	0	0.01	0	0.04	0.61
830,000	Percent	0	0.01	0.14	0.07	0.13	0.07	0.03	0	0.03	0.03	0	0.01	0.01	0.01	0.01	0	0	0	0.57
840,000	Percent	0	0	0.1	0.16	0.11	0.07	0.1	0.03	0	0.04	0.03	0.01	0	0	0	0	0	0	0.65
850,000	Percent	0	0.01	0.08	0.07	0.13	0.08	0.04	0.04	0.06	0.01	0	0	0	0	0	0.01	0	0.03	0.58
860,000	Percent	0	0.03	0.01	0.06	0.08	0.07	0.03	0.04	0.01	0	0	0.01	0.01	0.03	0	0	0	0.01	0.41
870,000	Percent	0	0	0.04	0.11	0.13	0.06	0.03	0.08	0	0	0.04	0	0	0	0.01	0	0.01	0.01	0.54
880,000	Percent	0	0	0.06	0.1	0.11	0.08	0.03	0.03	0.01	0	0.01	0.01	0	0	0.01	0	0.01	0	0.48
890,000	Percent	0	0	0.07	0.01	0.1	0.11	0.08	0.03	0.06	0.03	0.01	0	0	0.01	0	0.01	0	0	0.54
900,000	Percent	0	0	0.03	0.04	0.06	0.08	0.07	0.07	0	0.04	0.01	0.01	0.01	0	0	0	0	0	0.44
910,000	Percent	0	0	0.07	0.04	0.11	0.08	0.08	0.06	0.03	0.01	0.03	0	0	0	0.01	0	0	0.01	0.55
920,000	Percent	0	0	0.04	0.04	0.13	0.03	0.1	0.01	0.03	0.01	0.01	0	0.01	0.01	0	0.01	0	0	0.45
930,000	Percent	0	0.01	0.01	0.1	0.16	0.08	0.1	0.06	0.04	0.01	0.01	0.06	0	0	0.01	0.01	0	0.03	0.71
940,000	Percent	0	0	0.06	0.06	0.04	0.08	0.06	0.01	0.03	0.01	0.01	0.03	0.01	0	0	0	0	0	0.41
950,000	Percent	0	0	0.04	0.06	0.08	0.08	0.03	0.04	0.06	0.03	0.01	0.01	0	0	0.01	0	0	0.04	0.51
960,000	Percent	0	0	0	0.06	0.06	0.07	0.01	0.01	0.01	0.03	0	0.01	0.01	0.01	0.01	0.01	0	0	0.32
970,000	Percent	0	0	0.04	0.03	0.08	0.03	0.01	0.04	0.01	0.01	0.01	0	0	0	0.01	0	0	0	0.3
980,000	Percent	0	0	0.01	0.07	0.06	0.04	0.06	0.06	0.03	0	0.03	0	0	0	0	0	0	0	0.35
990,000	Percent	0	0	0.01	0.06	0.08	0.03	0.04	0.01	0.03	0.06	0.04	0	0.01	0	0	0	0.01	0.01	0.41
1,000,000	Percent	0	0	0	0.03	0.01	0.04	0.04	0.06	0.04	0	0.01	0.03	0	0	0	0	0.01	0.01	0.3
>1,000,000	Percent	0	0	0.11	0.57	1.02	1.7	1.98	2.18	2.2	2.11	2.08	2.05	1.85	1.53	1.3	0.97	0.96	15.06	37.66
Total	Percent	7.39	8.37	10.06	10.16	9.07	7.22	5.28	4.68	4.1	3.55	3.09	2.94	2.23	1.85	1.61	1.24	1.24	15.91	100

9.0 Topic: Freshet Pilot

Reference: Chapter 7, Page 7-40 and Appendix C-5B

One of the identified drivers of Freshet rate take-up is the customer's ability to increase production capacity. It is likely in many cases that increasing production would depend on customers investing new capital to increase production capacity.

1.9.1 Please confirm that typically customers prefer longer term assurance before making capacity investments and given that the pilot is only two years in duration, customer take-up of the pilot may be limited and as such, may not be representative of potential take-up if the rate was permanent.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 1.76.1.

9.0 Topic: Freshet Pilot

Reference: Chapter 7, Page 7-40 and Appendix C-5B

One of the identified drivers of Freshet rate take-up is the customer's ability to increase production capacity. It is likely in many cases that increasing production would depend on customers investing new capital to increase production capacity.

1.9.1.1 Please confirm that BC Hydro has made an assessment of whether there is broad interest in the Freshet Pilot program amongst all RS 1823 customers?

RESPONSE:

Confirmed. Please refer to section 2.2.3.4 of Exhibit B-1, page 2-26, line 20 to page 2-27, line 12. Most of the freshet related meetings occurred with AMPC. As noted in AMPC's intervention application (Exhibit C12-1), AMPC members "are transmission level customers of BC Hydro in the pulp and paper, forestry, mining, electrochemical and petrochemical sectors, and collectively represent a significant majority of BC Hydro's large industrial load".

BC Hydro also notes CAPP's statement in its intervention application, Exhibit C13-1, page 2 where CAPP states it is amenable "to an expedited process for the freshet rate pilot so that other customers could have an opportunity to take advantage of this service in 2016."

9.0 Topic: Freshet Pilot

Reference: Chapter 7, Page 7-40 and Appendix C-5B

One of the identified drivers of Freshet rate take-up is the customer's ability to increase production capacity. It is likely in many cases that increasing production would depend on customers investing new capital to increase production capacity.

1.9.1.2 If confirmed, please provide the findings of the assessment, including whether RS 1823 customers in certain industry sectors were less supportive of the proposal.

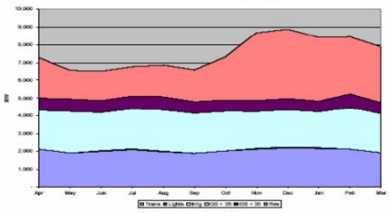
RESPONSE:

Please refer to BC Hydro's response to FortisBC IR 1.9.1.1.

10.0 Topic: Monthly Peak by Class

Reference: BCH 2007 Phase 1 RDA Decision, page 74

Table 3-4
Contribution to Monthly Peak by Class



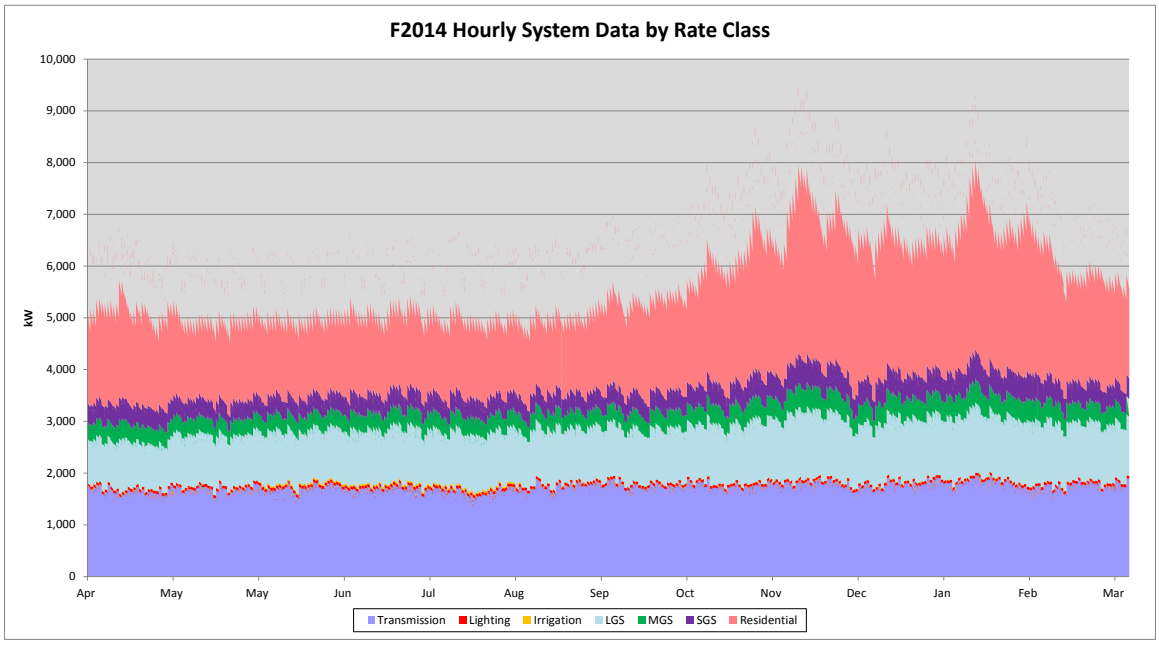
Source: Exhibit B-3, Terasen 1.9.1

1.10.1 Please reproduce the graph from page 74 of the BCH 2007 Phase 1 RDA Decision using the most recent data from F2015 for the monthly peak by class.

RESPONSE:

The updated graph uses F2014 hourly data. BC Hydro notes the following:

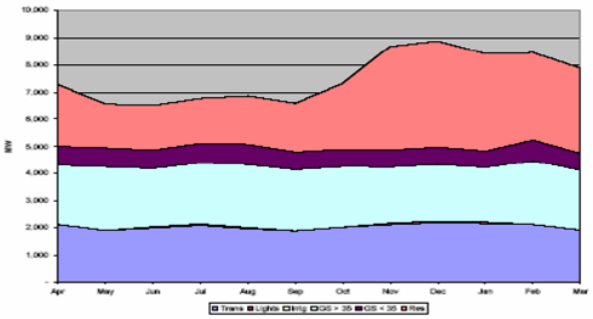
- **Load shape is largely similar to F2007;**
- **Hourly data gives the graph below a jagged rather than smooth shape; and**
- **General Service > 35 is now two rate classes: MGS and LGS.**



10.0 Topic: Monthly Peak by Class

Reference: BCH 2007 Phase 1 RDA Decision, page 74

Table 3-4
Contribution to Monthly Peak by Class



Source: Exhibit B-3, Terasen 1.9.1

1.10.1.1 To the extent that the shape of the graph has changed, please explain the factors that contribute to this change.

RESPONSE:

Please refer to BC Hydro's response to FortisBC IR 1.10.1.

CITY OF
VANCOUVER

November 17, 2015

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z2N3

Attention: Ms. Erica Hamilton, Commission Secretary

RE: BC Hydro 2015 Rate Design Application

Please find enclosed the City of Vancouver, Neighbourhood Energy Utility's first set of Information Requests with respect to the above noted matter.

A copy of this letter and attached information request have also been forwarded to BC Hydro and registered interveners by email.

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

Yours truly,

Kieran McConnell, P.Eng., LEED AP.
Systems Engineer
KM/
320-507 West Broadway, Vancouver, BC
tel: 604.871.6981

cc: BC Hydro
cc: Registered Interveners

15th ANNIVERSARY EDITION: 2000-2015
Canada's Top 100 Employers 2015
2015 BC's Top Employers

1. Reference: Exhibit B-1, page 6-38

1.1 Please provide the ten year cost implications on an annual basis of the LGS proposal for a typical thermal energy utility, based on the load profile provided below. Please compare to the cost implications under the current LGS rate structure. Assume the electrical energy increases 10% each year and the electrical demand grows 2% each year.

Typical Load profile (year 1)

	Electrical Energy (kWh)	Monthly Peak Electrical Demand (kW)
January	785,000	1,250
February	750,000	1,250
March	750,000	1,250
April	625,000	1,000
May	500,000	750
June	420,000	750
July	365,000	700
August	365,000	700
September	400,000	750
October	625,000	1,000
November	750,000	1,250
December	800,000	1,250

Load Growth - year by year

	Electrical Energy Growth (%)	Monthly Peak Electrical Demand (kW)
Year 1	5%	2%
Year 2	5%	2%
Year 3	5%	2%
Year 4	5%	2%
Year 5	5%	2%
Year 6	5%	2%
Year 7	5%	2%
Year 8	5%	2%
Year 9	5%	2%
Year 10	5%	2%

1.2 Please provide the ten year cost implications on an annual basis of the LGS proposal for a typical thermal energy utility which adds a major capital upgrade in year 4 to double production, based on the load profile provided below. Please compare to the cost implications of the current LGS rate structure.

Typical Load profile (year 1)

	Electrical Energy (kWh)	Monthly Peak Electrical Demand (kW)
January	785,000	1,250
February	750,000	1,250
March	750,000	1,250
April	625,000	1,000
May	500,000	750
June	420,000	750
July	365,000	700
August	365,000	700
September	400,000	750
October	625,000	1,000
November	750,000	1,250
December	800,000	1,250

Load Growth

	Electrical Energy Growth (%)	Monthly Peak Electrical Demand (kW)
Year 1	5%	2%
Year 2	5%	2%
Year 3	5%	2%
Year 4	100%	100%
Year 5	5%	2%
Year 6	5%	2%
Year 7	5%	2%
Year 8	5%	2%
Year 9	5%	2%
Year 10	5%	2%

1.0 Reference: Exhibit B-1, page 6-38

1.1.1 Please provide the ten year cost implications on an annual basis of the LGS proposal for a typical thermal energy utility, based on the load profile provided below. Please compare to the cost implications under the current LGS rate structure. Assume the electrical energy increases 10% each year and the electrical demand grows 2% each year.

Typical Load profile (year 1)

	Electrical Energy (kWh)	Monthly Peak Electrical Demand (kW)
January	785,000	1,250
February	750,000	1,250
March	750,000	1,250
April	625,000	1,000
May	500,000	750
June	420,000	750
July	365,000	700
August	365,000	700
September	400,000	750
October	625,000	1,000
November	750,000	1,250
December	800,000	1,250

Load Growth – year by year

	Electrical Energy Growth (%)	Monthly Peak Electrical Demand (kW)
Year 1	5%	2%
Year 2	5%	2%
Year 3	5%	2%
Year 4	5%	2%
Year 5	5%	2%
Year 6	5%	2%
Year 7	5%	2%
Year 8	5%	2%
Year 9	5%	2%
Year 10	5%	2%

RESPONSE:

This response answers NEU IRs 1.1.1 and 1.1.2.

By way of background, NEU is City of Vancouver's district heating system supplying space heating and domestic water to the Southeast False Creek area of Vancouver. NEU has LGS and MGS accounts, and at Workshop 8a relayed that it

had problems with the existing LGS rate due to phased development; refer to the Workshop 8a/8b consideration memo, Exhibit B-1, Appendix C-4A, Attachment 1, page 227 of 813.

BC Hydro modelled the illustrative cost estimates for F2017, F2018 and F2019, given that the RRA increases were assumed to be the rate caps set out in Direction No. 7 and given that BC Hydro is applying for pricing principles for F2017 to F2019. As described in section 1.1.3 of Exhibit B-1, BC Hydro is seeking Commission approval of pricing principles for the RIB rate and RS 1823 for the F2017 to F2019 period only. BC Hydro respectfully declines to provide illustrative cost estimates for F2020 to F2026 on the basis that such information is not relevant to and cannot aid in the review of 2015 RDA Module 1 or the orders sought with respect to it. BC Hydro notes that a discussion of BC Hydro's forecasted rate increases for the period F2020 to F2024 will occur as part of its F2017 RRA filing in February 2016.

The following assumptions are used in providing the estimates:

- **"Year 0" is defined as F2016, which has the load profile as stated in the table "Typical load profile (year 1)";**
- **"Year 1" is defined as F2017, and the consumption for that year has the load growth percentage as stated in the chart "Load Growth – year by year" already applied;**
- **Annual consumption and demand growth are uniformly distributed throughout the year;**
- **Energy consumption in F2016 and prior reflects the "typical load profile (year 1)" table, such that the consumption equals baseline; and**
- **The 100 per cent expansion in the "Load Growth" table set out in NEU IR has been moved up to "Year 3" to illustrate the effect of substantial growth.**

The resulting consumption and demand forecasts assumptions, by component, are as follows:

	Annual Consumption Assumptions		Energy Part 1 – Baseline (kWh)			Energy Part 2 (kWh)			Billed Demand Assumptions (kW)		
	Energy (kWh)	Billed Demand (kW)	Part 1 Total	Tier 1	Tier 2	Part 2 Total	Part 2 LRMC	Part 2 Tier 2	Tier 1	Tier 2	Tier 3
F2016	7,135,000	11,900	7,135,000	177,600	6,957,400	-	-	-	420	1,380	10,100
F2017 (Year1)	7,491,750	12,138	7,135,000	177,600	6,957,400	356,750	356,750	-	420	1,380	10,338
F2018 (Year 2)	7,866,338	12,381	7,253,917	177,600	7,076,317	612,421	612,421	-	420	1,380	10,581
F2019 (Year 3)	8,259,654	12,628	7,497,696	177,600	7,320,096	761,959	761,959	-	420	1,380	10,828
F2019 (Year 3) 100% Expansion	15,732,675	24,762	7,497,696	177,600	7,320,096	8,234,979	1,499,539	6,735,440	420	1,380	22,962

The cost implications excluding DARR, given the assumptions above, are as follows:

	Existing LGS Rate ($)			LGS Proposal (Flat Energy, Flat Demand, 65% Demand Cost Recovery) ($)		
	Energy	Demand	Total	Energy	Demand	Total
F2017 (Year 1)	429,482	121,301	550,784	402,307	131,455	533,762
F2018 (Year 2)	480,026	128,261	608,287	437,368	138,788	576,157
F2019 (Year 3)	531,403	135,002	666,405	472,452	145,731	618,184
F2019 (Year 3) 100% Expansion	1,004,293	276,838	1,281,131	899,909	285,748	1,185,657

1.0 Reference: Exhibit B-1, page 6-38

1.1.2 Please provide the ten year cost implications on an annual basis of the LGS proposal for a typical thermal energy utility which adds a major capital upgrade in year 4 to double production, based on the load profile provided below. Please compare to the cost implications of the current LGS rate structure.

Typical Load profile (year 1)

	Electrical Energy (kWh)	Monthly Peak Electrical Demand (kW)
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May	500,000	750
June	420,000	750
July	365,000	700
August	365,000	700
September	400,000	750
October	625,000	1,000
November	750,000	1,250
December	800,000	1,250

Load Growth

	Electrical Energy Growth (%)	Monthly Peak Electrical Demand (kW)
Year 1	5%	2%
Year 2	5%	2%
Year 3	5%	2%
Year 4	100%	100%
Year 5	5%	2%
Year 6	5%	2%
Year 7	5%	2%
Year 8	5%	2%
Year 9	5%	2%
Year 10	5%	2%

RESPONSE:

Please refer to BC Hydro's response to NEU IR 1.1.1.

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Energy Consulting

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VIA EMAIL
bchydroregulatorygroup@bchydro.com

November 17, 2015

Mr. Tom Loski
Chief Regulatory Officer
Regulatory & Rates Group
British Columbia Hydro and Power Authority
16th Floor - 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Mr. Loski:

RE: British Columbia Hydro and Power Authority
2015 Rate Design Application

Further to your September 24, 2015 filing of the 2015 Rate Design Application and the Regulatory Timetable set out in Order G-166-15, enclosed please find the Zone II Ratepayers Group Information Request No. 1 in accordance with the Regulatory Timetable.

Yours truly,

Linda Dong

Linda Dong

Enclosure
cc: Registered Interveners

REQUESTOR NAME: **Zone II Ratepayers Group (ZONEII)**

INFORMATION REQUEST ROUND NO: 1

TO: **British Columbia Hydro & Power Authority**

DATE: **November 17, 2015**

APPLICATION NAME: **BC Hydro 2015 Rate Design Application (RDA)**

1.0 Reference: Exhibit B-1, P 3-20, 21

Topic: Regulatory and Deferral Accounts

Explanation: The RDA deals with only a small fraction of the total Regulatory and Deferral Accounts ("Accounts") of over $5 billion, an amount that is growing rapidly. The Accounts now significantly exceed the annual domestic revenue and retained earnings of BC Hydro.

Request:

1.1 What is the forecast balance of the Regulatory and Deferral Accounts at the end of F2016?

1.2 When will BC Hydro begin recovering and reducing the balances in the Accounts?

1.3 What is the anticipated impact of the Accounts recovery on rate increases and the ability of NIA customers to absorb significant rate increases, changes to NIA rates and the costs of using electricity for hot water and space heating when they have no viable options?

2.0 Reference: Exhibit B-1, Appendix C-2B, P 95 of 205

Topic: Line Losses

Explanation: *"Although BC Hydro expects there to be loss reduction-related energy savings from SMI in F2016, these savings are estimates at the present time (line losses cannot be measured directly until BC Hydro has fully deployed system metering, anticipated to be December 2015). BC Hydro believes it would be prudent to wait three years before considering whether energy-related benefits from SMI should be incorporated in the COS classification methodology."*

Request:

2.1 Provide the annual line losses or if not available, the line losses and system use as experienced by BC Hydro since 2006.

2.2 Confirm that line loss (unaccounted for) reductions due to SMI are not being recorded in Regulatory Accounts as a benefit of SMI and are appearing as increased revenue to BC Hydro.

2.3 Confirm that the BC Hydro Cost of Service is based on an estimate of line losses and system use.

2.4 What is the annual line loss for NIAs vs. annual line loss in the integrated system since 2006?

2.5 Provide the current BC Hydro estimate of the line loss reduction and rate for 2016 vs. the line losses in the Cost of Service.

3.0 Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Topic: NIA Residential Class Characteristics

Explanation: Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

Request:

3.1 Provide Average Residential Class Consumption by Month, F2011-F2015 (GWh) in the form of Figure 5-2 for NIA.

3.2 Provide Total Consumption by Region (GWh) in the form of Figure 5-3, P 5-9 for NIA.

3.3 Provide Customer Accounts by Region in the form of Figure 5-4, P 5-9 for NIA.

3.4 Provide Total Consumption by Dwelling Type in the form of Figure 5-5, P 5-10 for NIA.

3.5 Provide Customer Accounts by Dwelling Type in the form of Figure 5-6, P 5-11 for NIA.

3.6 Provide Customer Accounts by Heating Type in the form of Figure 5-7, P 5-12 for NIA.

3.7 Provide Proportion of Low Income Customer Accounts in the form of Figure 5-8, P-5-13 for NIA.

3.8 Provide Proportion of Low Income, Electrically Heated Customer Accounts in the form of Figure 5-9, P-5-13 for NIA.

3.9 Provide Proportion of Low Income, Electrically Heated Customer Accounts in the form of Figure 5-9, P-5-13 for NIA.

3.10 Provide Total Consumption by Household Size in the form of Figure 5-10, P-5-14 for NIA.

3.11 Provide Customer Accounts by Household Size in the form of Figure 5-11, P-5-15 NIA.

3.12 Provide a chart showing customer accounts by heating type for various fuel heating options for NIA.

3.13 Provide average summer and winter temperature data as expressed in Degree Day Deficiency or Heating Degree Day, as applicable, across all NIA and Zone I regions.

4.0 Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

Topic: Cost of Energy

Explanation: NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:

" Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

Request:

4.1 Provide the range of costs per MWh for each of IPPs and NIAs.

4.2 What is the range of costs for BC Hydro Heritage supply including Ruskin and John Hart?

4.3 Explain why there are increasing marginal costs of diesel generation.

1.3.1 Provide a table of historical and forecast diesel prices from 2013 to 2016.

4.4 What opportunities exist to reduce NIA generation costs and what are the constraints on implementation?

4.5 Does BC Hydro have an inventory of electric appliances in NIAs?

4.6.1 What is the penetration rate of electric space heating in NIAs?

4.6.2 Heat pumps including split zone systems?

4.6.3 Baseboard electric?

4.6.4 Electric furnaces?

4.6.5 Electric-Wood Combination furnaces?

4.6 What is the penetration rate of electric hot water tanks in the NIAs?

4.7 Are there opportunities for using the waste heat from diesel generation (hot water, space heating, etc.)?

4.8 What economic and reliable energy alternatives to electricity exist in NIAs?

4.9 What economic and reliable electricity generation options exist in NIAs?

5.0 Reference: Exhibit B-1, Appendix C-3B, P 320 of 609; Exhibit B-1, Chapter 5, P 5-74-78; Table 8-6, P 8-24 to 8-27; Electricity Servicing Agreement – February 14, 2013, s. 8.1; 2014; San Diego Energy OutWest Conference "Engaging the Human Factor" and "Quality Program Services", Attachment 1 (http://www.energyoutwest.org/conference/2014-conference/2014presentations/)

Topic: DSM and Electricity Affordability

Explanation: *"… BC Hydro plans to include information on low income Demand Side Management (DSM) programs."*

"BC Hydro also provides capacity funding to non-profit housing providers and aboriginal units to assist them to hire someone locally to help promote the ESK and ECAP programs and collect application forms from tenants and/or members of the community on behalf to the two programs."

Prior to BC Hydro commencing service to Kwadacha Nation as part of the Remote Community Electrification (RCE) program, residential rates were $0.055/kWh. Now that Kwadacha Nation is in BC Hydro's service area, residential rates average $0.12-0.13/kWh. Electricity affordability is a key issue where community members rely on income assistance (average $540 monthly).

Cost of living (including food, supplies, etc.) is higher in remote communities Remoteness contributes to higher electricity consumption due to the colder climate and the need for such things as freezers to store food since they do not have ready access to grocery stores. Also due to unemployment, multigenerational living and remoteness of the community, residents spend more time in their homes resulting in increased electricity consumption.

Some residents of the NIA communities suffer from financial and emotional stresses as a result of low income combined with high energy costs, payment difficulties and delays in implementing appropriate energy education and retrofit programs.

Request:

5.1 What communications, if any, has BC Hydro had to explain the reasons for the significant increase in residential rates?

5.2 What DSM programs are in place for NIAs? What has been the success of ESK's and ECAP to date?

5.3 What DSM programs are in place for First Nations communities?

5.4 What specific actions has BC Hydro taken to reduce electricity consumption in remote communities?

5.5 What options are there for additional DSM programs for First Nations and NIA communities?

5.6 Is BC Hydro prepared to provide a BC Hydro key account/energy manager for First Nations communities to focus on DSM and supply options and work with contractors and communities on programs specific to NIAs and First Nations needs in a timely manner?

6.0 Reference: Exhibit B-1, Appendix C-3B, P 258 of 609

Topic: Residential Zone II (RS 1107, 1127)

Explanation: BC Hydro states that:

"For consumption beyond 1500 kWh/month, Residential customers in Zone II pay a higher rate to discourage electric space heating from diesel-generated electricity."

NIAs do not have clean, reliable and economic heating options such as natural gas and therefore need to rely on electric space heating in some cases, including as backup. As well, residences in the NIA are not built to the same standards as homes in the Zone I area and in many cases are northern communities, resulting in increased electricity consumption.

Request:

6.1 Provide data showing range and average of electrical consumption for Zone II households with electric heat and water by region.

6.2 Provide data showing range and average electrical consumption for Zone I households with electric heat and water by region.

6.3 Provide data showing range and average of electrical consumption for Zone II households without electric heat and water by region.

6.4 Provide data showing range and average electrical consumption for Zone I households without electric heat and water by region.

7.0 Reference: Exhibit B-1, Appendix C-3B, P 267 of 609

Topic: Equalizing Zone I and Zone II Residential customers

Explanation: BC Hydro provides information on the impact of equalizing Zone II and Zone I rates and states that:

"Most Zone II residential customers would see a bill decrease, with the largest bill reductions available to the largest consumers;

Assuming no change in residential consumption behaviour, the amount of the under-recovered costs in Zone II is estimated to increase approximately $300,000...."

Request:

7.1 Please provide detailed information, such as bill impact data, to support the statement that "most customers would see a bill decrease".

7.2 Does BCH consider $300,000 to be significant and a barrier to implementing a single Residential rate?

8.0 Reference: Exhibit B-1, Appendix C-3B, Attachment 8, P 609 of 609; Appendix C-3B, P 257 of 609; Appendix C-3B, P261 of 609;

Topic: General Service customers

Explanation: In attachment 8, BC Hydro provides information on estimated number of General Service Customers in Zone II Non-Integrated Areas, by Site Type, Region and Rate Schedule. In addition, BC Hydro states that:

"Revenues from GS customers in Zone II are near 50 percent of all Zone II revenues."

The information provided by BC Hydro is limited with respect to General Service in Zone II. In order to determine impact of General Service Rate changes on Zone II additional information on bill impacts is required.

Request:

8.1 Provide a comparison of Zone 1 and Zone II GS rates in the form of Figure 1, Appendix C-3B, P 261 of 609 for SGS, MGS and LGS as applicable.

9.0 Reference: Exhibit B-1, Tables 8-1 (P 8-6), 8-2 (P-7), 8-3 (P 8-8), 8-4 (P 8-12), 8-5 (P-13), 8-6 (8-24)

Topic: Bill Payment

Explanation: In some NIA communities there are no local banks and the closest bank may be located far away from the community. Ratepayers do not have bank accounts and do not have easy access to make bill payments to BC Hydro. BC Hydro in its proposed changes to the electric tariff terms and conditions does not propose any changes to bill payment options that recognize the unique circumstances that exist in remote communities.

Request:

9.1 What bill payment options are available to those ratepayers that do not have a bank account or even local access to a bank?

10.0 Reference: Exhibit B-1, Table 8-6, P8-24 to 8-27

Topic: Disconnection

Explanation: Electricity affordability, bi-monthly billing and access to financial institutions are a key issue. The threat of disconnection is extremely disruptive and stressful for residents who have few if any heating options and have experienced significant change since BC Hydro began providing service. In addition, under Equalized Billing once an account holder on the Equal Payment Plan misses a payment or pays a lesser amount, they are moved back to the standard billing terms and may be faced with immediate payment due to BC Hydro causing additional stress. BC Hydro states in Table 8-6 (Winter Disconnects; P8-27) that:

"BC Hydro is investigating the feasibility of using smart meters to limit the allowable load to a customer. If practical, this would allow a customer facing disconnection to be provided with a minimal supply of electricity (i.e. to allow some heating) but also limit the exposure to further non-collection.."

Request:

10.1 Please provide specifics and quantify "the minimal supply of electricity" and how that relates to an isolated northern community.

10.2 For remote communities how will BC Hydro consider lack of available heating options when determining the "minimal supply of electricity"?

10.3 Explain "limit the exposure to further non-collection". Specify and quantify the actions with and without the "limit" BC Hydro is considering.

10.4 What other options has BC Hydro considered to address the financial and geographic differences in disconnection policies in remote communities?

10.5 Will BC Hydro consider implementing a "grace period" for account holders in the event of a missed or partial payment under the Equal Payment Plan prior to moving the account holder back to standard billing?

10.6 Will BC Hydro consider implementing monthly vs. bi-monthly billing in order to assist account holders for budgeting purposes?

10.7 To assist residents in remote communities with high incidence of disconnection, would BC Hydro consider having a party work one-on-one with residents requiring education and other assistance or facing disconnection to develop payment solutions for the residents?

Attachment 1
Zone II IR 1-5

ENGAGEMENT: THE HUMAN FACTOR IN ENERGY EFFICIENCY

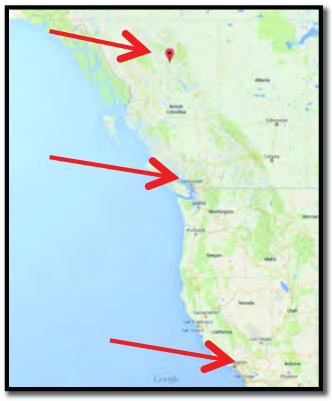
THE KWADACHA NATION

BC HYDRO (UTILITY)

QUALITY PROGRAM SERVICES (CONTRACTOR)

THE KWADACHA NATION

- **Fort Ware, home of the Kwadacha Nation Tsek'ene**
- **250 miles from the closest town Mackenzie, BC (population 4500);**
  - 1300 mi from Vancouver, BC
  - 2000 mi from San Diego, Ca
- **Accessible by small plane, or since 1992, by logging road (an 8 - 10 hour drive)**
- **One of the most remote, isolated communities**
- **Kwadacha Nation is one of five nations that make up the Kaska Dena, the traditional territory (92,000 sq miles)**



A BRIEF HISTORY OF KWADACHA

- Tsek'ene people gradually moved west into BC from the Rocky Mountains beginning 11-12,000 years ago as the glacial ice melted
- As migratory people, Tsek'ene people had no permanent settlements, lived in small mobile family groups which followed constantly-moving animals, had a cooperative but less formal social structure, and minimal material goods due to frequent travel by foot.
- 1793 for next 100 yrs, Tsek'ene people began trading with Hudson Bay Company
- 1930's first generation of children were sent to Lejac Residential School, over 600 km southwest of the emerging village of Fort Ware.
- Social, political, and economic changes that most Canadian First Nations experienced over two to three centuries were compressed into roughly 100 years for Kwadacha Tsek'ene peoples.
- The ultimate, irrevocable change occurred in the 1960's and early 70's when Tsek'ene lands, waterways, trails, trap lines, and hunting areas were flooded by the Williston Reservoir caused by the W.A.C. Bennett Dam built across the Peace River on the eastern side of the Rocky Mountains.

PEOPLE OF KWADACHA

- **400 people living in Fort Ware of which 380 are Kwadacha Nation members (also 145 off-reserve members living in nearby communities)**
- **Employment in Fort Ware consists of Band and Health Administration, Education, Public Works, and Forestry, Mining and Oil & Gas industries.**
- **10 to 12% of community members rely on Income Assistance and see on average about $540 monthly**
- **Community buildings include the school, Health and Administration Centre, and a general store and restaurant**
- **Aatse Davie School (K-Grade 12) has 92 students**
  - All students take Tsek'ene class (traditional language)
  - Also classes on stories, language, crafts, sewing, and other traditional activities.
- **Governed by an elected Chief and Council**

HOUSING AND ELECTRICITY IN KWADACHA

- **Most homes on reserve owned by Kwadacha Nation and rented to residents**
- **Most homes are bank financed with a modest subsidy from the Federal Government**
- **Wood is predominant heat source**

Housing Challenges:

- **Balancing housing needs and rent collections**
- **5.5 persons per dwelling (Provincial average is 2.75) - demand exceeds capacity by about 20 homes.**
- **25 homes in need of major renovation and/or upgrades**

KWADACHA AND BC HYDRO

Electricity:

- **Electricity came to the community 30 yrs ago through federally funded Diesel Generating Power Station**
- **2005 Kwadacha Nation contracted with BC Hydro to operate the plant; residential rates were 5.5 c/ kWh**
- **Although plant operations partially funded by the federal government, a huge deficit was created.**
- **2008 Kwadacha Nation and BC Hydro reached a settlement agreement as a result of the flooding of the territory in the 1960's by BC Hydro's WAC Bennet Dam**
- **2012, Kwadacha Nation Green Initiative by Chief Donny Van Somer to become a BC Hydro customer under RCE Program**

OVERVIEW: **BC HYDRO**

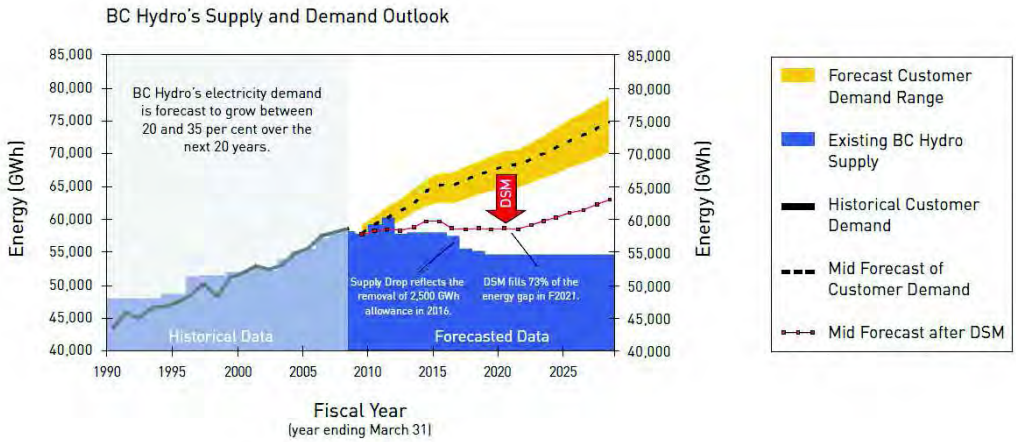
- Crown corporation, established in 1961
- 3rd largest electric utility in Canada
- 31 hydroelectric facilities + 3 thermal generating plants = 12,000mw

ELECTRIFYING **REMOTE COMMUNITIES**

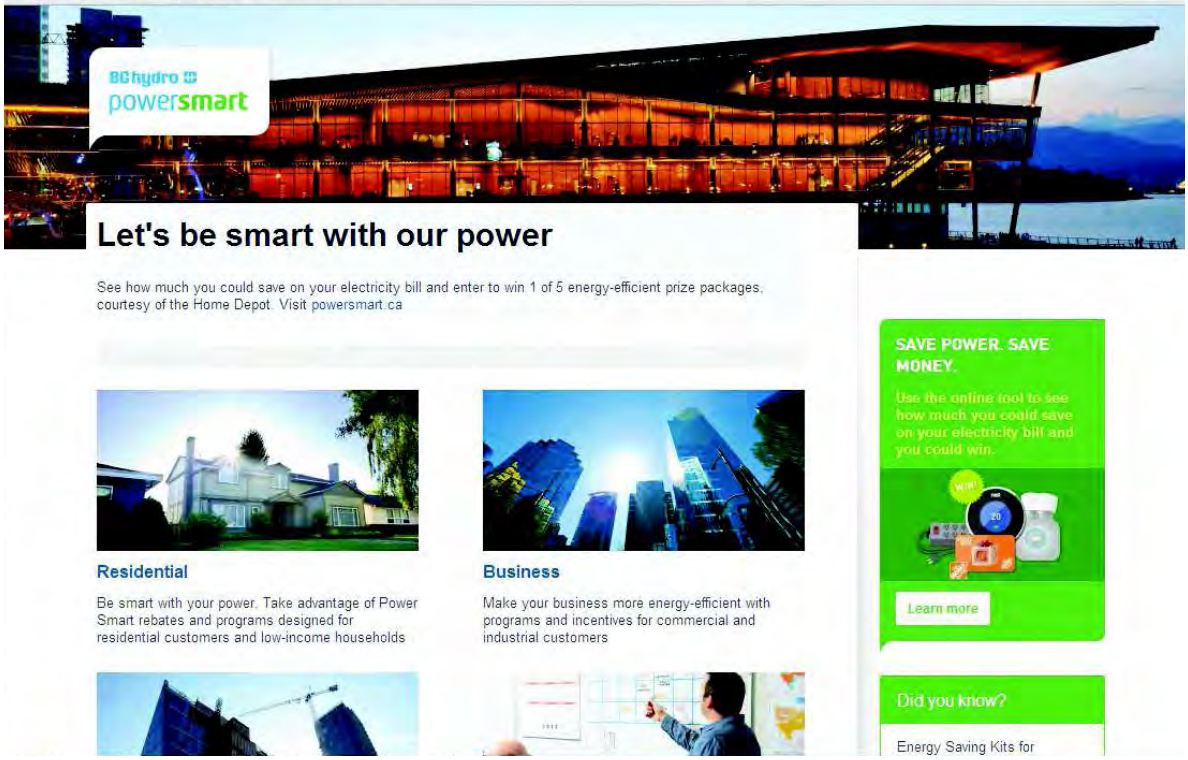
BC hydro
FOR GENERATIONS

COMMITMENT TO **ENERGY EFFICIENCY**

BC hydro
FOR GENERATIONS



powersmart



SUCCEEDING THROUGH **RELATIONSHIPS**

BC hydro
FOR GENERATIONS

- Duty to consult
- Historic grievance agreements
- Building long-term relationships

BC HYDRO & KWADACHA

Pre-1960:
Kwadacha's long and rich history before the dam…

1962-1964:
BC Hydro builds WAC Bennett Dam. Marvel of engineering, failure of relationships.

Early 1990s-2008:
Many years of negotiations.

2008:
BC Hydro and Kwadacha Nation sign Final Agreement.

2005-2012:
RCE program. Install diesel generating station and local distribution.

2012-present:
Demand-side management and energy efficiency programs.

ENERGY CONSERVATION IN KWADACHA

DIESEL GENERATION

+

$.35/ kwh

VS

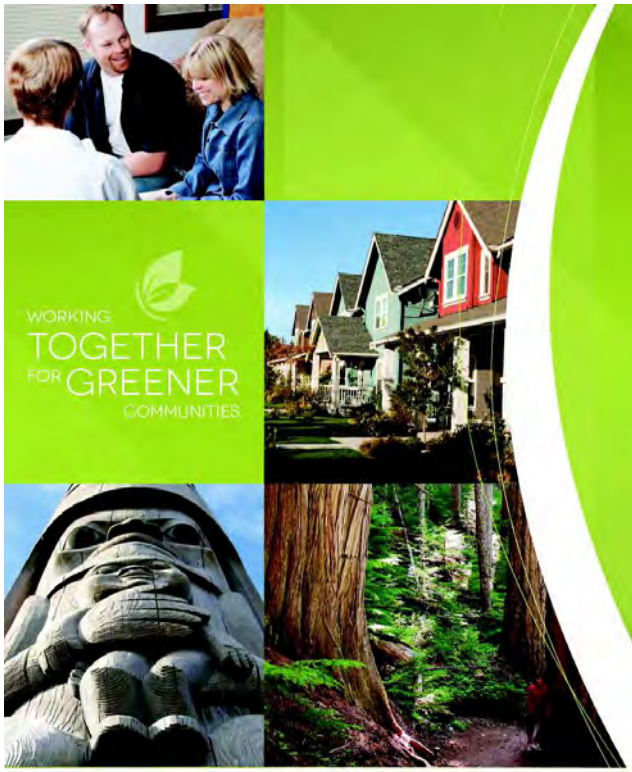
~.09/ kwh

COST TO PRODUCE ENERGY

+

HIGH BILLS

ENERGY CONSERVATION MAKES SENSE FOR EVERYONE!



QUALITY PROGRAM SERVICES

AREEF ABRAHAM

Quality PROGRAM SERVICES

302 - 14640 64th Avenue, Surrey, British Columbia V3S 1X7
604.598.8428 / info@qpscanada.ca / qualityprogramservices.ca

FINANCIAL AND CONSUMPTION INFO

- All electricity is diesel generated
- Residential consumption is 71% of generated power
- Avg. residential consumption 18,800 kWh/yr. = $2,740/yr
- 25% of homes consume over 25,000 kWh/yr. – average cost $4,800/yr.

Quality PROGRAM SERVICES

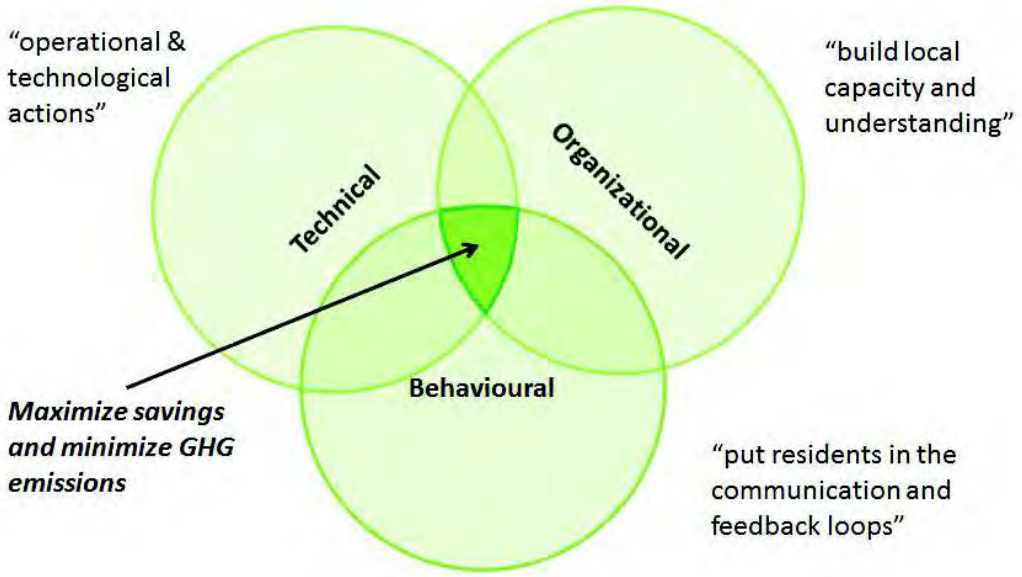
EFFECTIVELY CHANNELING MOTIVATIONS

Wood for space heating over electricity

1. Plentiful but requires harvesting
2. Sufficient financial motivations for residents, Band, and BC Hydro
3. Except individuals on Social Assistance (less incentive)
4. What about elders?

Quality PROGRAM SERVICES

OUR APPROACH



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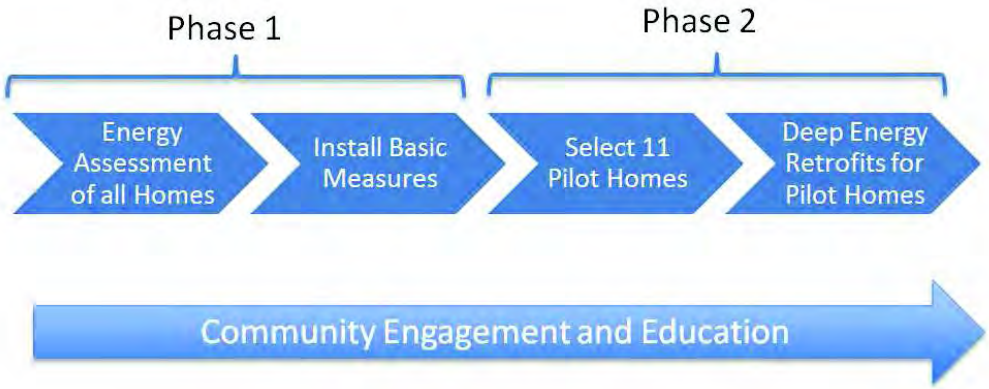
PROJECT TIMELINE 2010-2013



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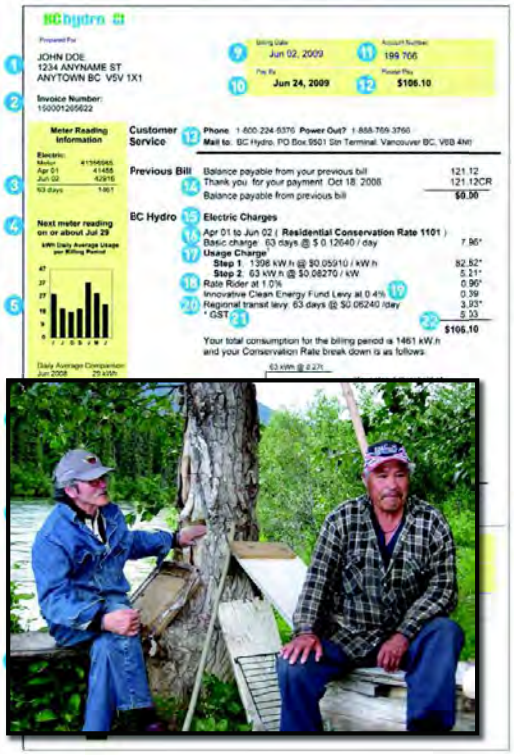
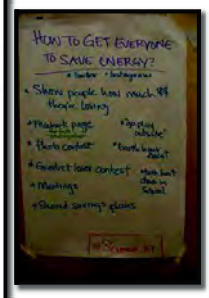
COMMUNITY ENGAGEMENT & EDUCATION

- Community Dinners
- Community Energy Champion
- Community Green Team
- Engage and train operations and maintenance Staff
- Build capacity in the community store



ENGAGEMENT



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PHASE 1: BASIC MEASURES

- Basic Air Sealing
- Window film
- Outlet Gaskets
- Nightlights
- CFLs
- Aerators
- HW pipe wrap
- Showerheads

$55,457
Cost of Installation

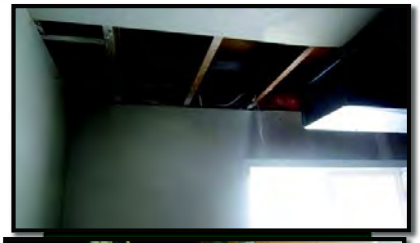
Impacts

Annual Savings	$15,000 (42,900 kWh)
NPV of savings	$94,685
Benefit cost ratio	1.71

Quality PROGRAM SERVICES

DATA & INFO COLLECTED

- Collecting data to run HOT2000 energy modeling
  - Building envelope
  - Air leakage
- Detailed information on space heating systems and controls
- Resident concerns

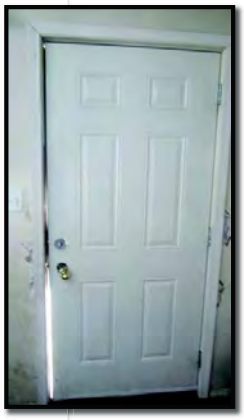


FINDINGS

Poor temperature control and lack of education on use

FINDINGS CONT.

- Space heating – poor temperature control
  - Forced air wood/electric furnaces
  - Wood stoves and baseboard heaters
- Crawl spaces had baseboard heaters to stop pipes freezing – poor temperature controls
- Air infiltration levels – Average 6.0 ACH, Max 18 and Min 2 ACH.
- Attic insulation – Average R31, Max R41 and Min R18 (recommended for climate zone R52).



Quality PROGRAM SERVICES

ANALYSIS FROM PHASE 1

Eliminate Waste

- Resident choices and behaviours
- Building Envelope
- Heating controls

Optimize Heating Choices

- Make wood the primary fuel
- Ensure wood burning equipment is safe, functional and efficient
- Make electricity the standby heating fuel

Quality PROGRAM SERVICES

PHASE 2: DEEP RETROFITS FOR 11 HOMES

- Disconnected electric furnaces and provide individual room temperature control
  - baseboard heaters controlled by digital programmable thermostats.
- Replace existing crawl space thermostats with digital models (set and forget)
- Maintain, repair, or replace all wood burning appliances in the homes.
- Thorough air sealing including box end joists
- Attic R60 insulation

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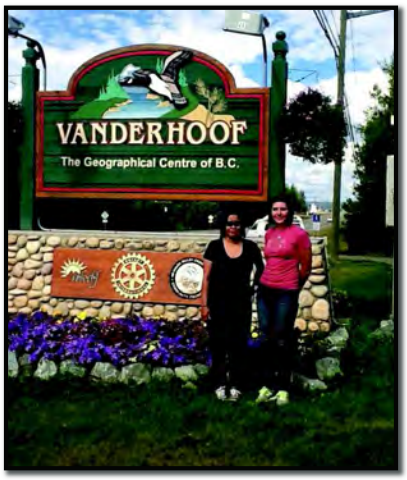
HOME EDUCATION: TRACY CHARLIE

Mitigate financial risk of retrofits through education

Community Energy Champion: Tracy Charlie



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PRELIMINARY PHASE 2 RESULTS

Kwh/yr.	Total	Average	%
Previous Consumption	**426,547**	**38,777**	**100**
Forecast savings from heating system and controls upgrades	95,792	8,708	22.5
Forecast savings from improved air tightness	32,142	2,922	7.5
Forecast savings from improved attic insulation	9,082	826	2.1
Total savings from DSM Interventions	**137,015**	**12,456**	**32.1**
Forecast Consumption	**289,532**	**26,321**	**67.9**
Current Consumption	**270,606**	**24,601**	**63.4**
Variance	**18,925**	**1,720**	**4.4**

Quality PROGRAM SERVICES

INDIVIDUAL HOMES

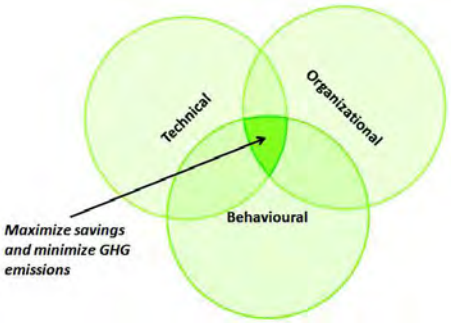
Home Ref #	Previous Consumption	Current Consumption	Reduction/ (Increase)	% Reduction/ (Increase)
1	51,985	28,095	23,890	46.0%
2	50,820	28,169	22,651	44.6%
3	47,232	53,752	(6,520)	(13.8%)
4	40,329	25,981	14,348	35.6%
5	35,125	13,802	21,323	60.7%
6	37,506	21,295	16,211	43.2%
8	34,918	18,004	16,914	48.4%
9	33,901	15,137	18,764	55.3%
10	32,418	34,250	(1,832)	(5.7%)
11	32,356	16,714	15,642	48.3%
13	29,957	15,407	23,890	48.6%

Quality PROGRAM SERVICES

CONCLUSION: THE APPROACH WORKS!

Next Steps:

- Collect and maintain baseline information and data on all community homes.
- Create purchasing and maintenance policies for appliances, doors, windows, air sealing and insulation.
- Integrate findings to create specifications for new homes.
- Develop a community based Green Energy Strategy
- Develop energy conservation incentives and feedback for residents



Quality PROGRAM SERVICES

WORKING TOGETHER FOR GREENER COMMUNITIES

Quality PROGRAM SERVICES

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1.0 Topic: Regulatory and Deferral Accounts

Reference: Exhibit B-1, P 3-20, 21

The RDA deals with only a small fraction of the total Regulatory and Deferral Accounts ("Accounts") of over $5 billion, an amount that is growing rapidly. The Accounts now significantly exceed the annual domestic revenue and retained earnings of BC Hydro.

1.1.1 What is the forecast balance of the Regulatory and Deferral Accounts at the end of F2016?

RESPONSE:

While BC Hydro notes that the overall forecasted balance of the regulatory and deferral accounts is not relevant to the F2016 COS review because it is only the amortized amounts that are included in the study, to be responsive BC Hydro offers the following. The forecast balances of the regulatory accounts and deferral accounts at the end of F2016 are $4,375.4 million and $444.5 million, respectively, as filed in BC Hydro's F15-F16 RRA.

1.0 Topic: Regulatory and Deferral Accounts

Reference: Exhibit B-1, P 3-20, 21

The RDA deals with only a small fraction of the total Regulatory and Deferral Accounts ("Accounts") of over $5 billion, an amount that is growing rapidly. The Accounts now significantly exceed the annual domestic revenue and retained earnings of BC Hydro.

1.1.2 When will BC Hydro begin recovering and reducing the balances in the Accounts?

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that it is not relevant to and cannot assist in the review of the 2015 RDA Module 1 or the orders sought with respect to it. Recovery of balances in regulatory and deferral accounts is appropriately addressed in the F2017 RRA, to be filed with the Commission in February 2016.

1.0 Topic: Regulatory and Deferral Accounts

Reference: Exhibit B-1, P 3-20, 21

The RDA deals with only a small fraction of the total Regulatory and Deferral Accounts ("Accounts") of over $5 billion, an amount that is growing rapidly. The Accounts now significantly exceed the annual domestic revenue and retained earnings of BC Hydro.

1.1.3 What is the anticipated impact of the Accounts recovery on rate increases and the ability of NIA customers to absorb significant rate increases, changes to NIA rates and the costs of using electricity for hot water and space heating when they have no viable options?

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the information sought is not relevant to and cannot aid in the review of the 2015 RDA or the orders sought in respect of it. The requested information is more relevant to a RRA proceeding. As outlined in section 1.3 of Exhibit B-1, BC Hydro is not seeking to increase its revenue requirements through 2015 RDA Module 1. The default Residential and General Service rate proposals are forecast revenue neutral (Exhibit B-1, page 1-19, lines 3 to 9).

In addition, as noted in section 1.5.2 of Exhibit B-1, page 1-21, line 14, BC Hydro is not proposing any changes to Zone II rates as part of 2015 RDA Module 1; Zone II rate design is a RDA Module 2 topic.

2.0 Topic: Line Losses

Reference: Exhibit B-1, Appendix C-2B, P 95 of 205

"Although BC Hydro expects there to be loss reduction-related energy savings from SMI in F2016, these savings are estimates at the present time (line losses cannot be measured directly until BC Hydro has fully deployed system metering, anticipated to be December 2015). BC Hydro believes it would be prudent to wait three years before considering whether energy-related benefits from SMI should be incorporated in the COS classification methodology."

1.2.1 Provide the annual line losses or if not available, the line losses and system use as experienced by BC Hydro since 2006.

RESPONSE:

Estimates of line losses and system use are found in BC Hydro's annual reports. The table below summarizes the losses between F2006 and F2015. BC Hydro's own system use accounts for about 65 GWh of the totals shown.

Year	Line Losses and BC Hydro System Use (GWh)
F2015	**4,486**
F2014	**4,733**
F2013	**5,159**
F2012	**4,783**
F2011	**4,648**
F2010	**4,840**
F2009	**5,391**
F2008	**5,677**
F2007	**5,329**
F2006	**5,356**

2.0 Topic: Line Losses

Reference: Exhibit B-1, Appendix C-2B, P 95 of 205

"Although BC Hydro expects there to be loss reduction-related energy savings from SMI in F2016, these savings are estimates at the present time (line losses cannot be measured directly until BC Hydro has fully deployed system metering, anticipated to be December 2015). BC Hydro believes it would be prudent to wait three years before considering whether energy-related benefits from SMI should be incorporated in the COS classification methodology."

1.2.2 Confirm that line loss (unaccounted for) reductions due to SMI are not being recorded in Regulatory Accounts as a benefit of SMI and are appearing as increased revenue to BC Hydro.

RESPONSE:

Confirmed. Line loss reduction attributable to SMI is not recorded in the SMI Regulatory Account. Such line loss reductions, if the result of energy now being paid for, would result in increased revenues.

2.0 Topic: Line Losses

Reference: Exhibit B-1, Appendix C-2B, P 95 of 205

"Although BC Hydro expects there to be loss reduction-related energy savings from SMI in F2016, these savings are estimates at the present time (line losses cannot be measured directly until BC Hydro has fully deployed system metering, anticipated to be December 2015). BC Hydro believes it would be prudent to wait three years before considering whether energy-related benefits from SMI should be incorporated in the COS classification methodology."

1.2.3 Confirm that the BC Hydro Cost of Service is based on an estimate of line losses and system use.

RESPONSE:

Confirmed.

2.0 Topic: Line Losses

Reference: Exhibit B-1, Appendix C-2B, P 95 of 205

"Although BC Hydro expects there to be loss reduction-related energy savings from SMI in F2016, these savings are estimates at the present time (line losses cannot be measured directly until BC Hydro has fully deployed system metering, anticipated to be December 2015). BC Hydro believes it would be prudent to wait three years before considering whether energy-related benefits from SMI should be incorporated in the COS classification methodology."

1.2.4 What is the annual line loss for NIAs vs. annual line loss in the integrated system since 2006?

RESPONSE:

The table below provides a comparison of the F2010 to F2015 line loss and system use as a percentage of Domestic Requirements for NIA in Zone II and the Integrated System.

Line Loss and System Use as a Percentage of Domestic Requirements	F2010 (%)	F2011 (%)	F2012 (%)	F2013 (%)	F2014 (%)	F2015 (%)
NIA in Zone II	**10.2**	**11.8**	**12.1**	**11.2**	**9.5**	**9.3**
Integrated System	**9.6**	**9.2**	**9.2**	**10.1**	**8.9**	**8.8**

Notes:

Pre-F2010 information for the NIA is not electronically available and would be labor intensive to obtain.

Iskut was excluded from the F2015 analysis as the community was transferred to Zone I rates.

There is a small mismatch between the generation production data used to calculate losses and BC Hydro's consumption data as the former is based on a fiscal year while the latter is based on billing periods that reasonably cover a fiscal year.

2.0 Topic: Line Losses

Reference: Exhibit B-1, Appendix C-2B, P 95 of 205

"Although BC Hydro expects there to be loss reduction-related energy savings from SMI in F2016, these savings are estimates at the present time (line losses cannot be measured directly until BC Hydro has fully deployed system metering, anticipated to be December 2015). BC Hydro believes it would be prudent to wait three years before considering whether energy-related benefits from SMI should be incorporated in the COS classification methodology."

1.2.5 Provide the current BC Hydro estimate of the line loss reduction and rate for 2016 vs. the line losses in the Cost of Service.

RESPONSE:

As shown in BC Hydro's response to Zone II IR 1.2.1, F2015 losses are estimated at 4,486 GWh which represents about 8.8 per cent of domestic sales (51,213 GWh) in F2015.

F2016 losses in the F2016 COS study are estimated at 5,390 GWh using a 6 per cent loss assumption for both the distribution and transmission systems. This represents about 10 per cent of BC Hydro's forecast F2016 domestic sales of 53,760 GWh.

3.0 Topic: NIA Residential Class Characteristics

Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

1.3.1 Provide Average Residential Class Consumption by Month, F2011-F2015 (GWh) in the form of Figure 5-2 for NIA.

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the requested information is not relevant to and cannot aid in the review of RDA Module 1 or the orders sought with respect to it. The requested information is not relevant to the review of the Zone I default Residential rate structure. As described on lines 13 to 15 on page 1-21 of Exhibit B-1, BC Hydro identified Zone II (NIA) as a topic that will be explored as part of Module 2 of the RDA.

3.0 Topic: NIA Residential Class Characteristics

Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

1.3.2 Provide Total Consumption by Region (GWh) in the form of Figure 5-3, P 5-9 for NIA.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.3.1.

3.0 Topic: NIA Residential Class Characteristics

Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

1.3.3 Provide Customer Accounts by Region in the form of Figure 5-4, P 5-9 for NIA.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.3.1.

3.0 Topic: NIA Residential Class Characteristics

Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

1.3.4 Provide Total Consumption by Dwelling Type in the form of Figure 5-5, P 5-10 for NIA.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.3.1.

3.0 Topic: NIA Residential Class Characteristics

Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

1.3.5 Provide Customer Accounts by Dwelling Type in the form of Figure 5-6, P 5-11 for NIA.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.3.1.

3.0 Topic: NIA Residential Class Characteristics

Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

1.3.6 Provide Customer Accounts by Heating Type in the form of Figure 5-7, P 5-12 for NIA.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.3.1.

3.0 Topic: NIA Residential Class Characteristics

Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

1.3.7 Provide Proportion of Low Income Customer Accounts in the form of Figure 5-8, P-5-13 for NIA.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.3.1.

3.0 Topic: NIA Residential Class Characteristics

Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

1.3.8 Provide Proportion of Low Income, Electrically Heated Customer Accounts in the form of Figure 5-9, P-5-13 for NIA.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.3.1.

3.0 Topic: NIA Residential Class Characteristics

Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

1.3.9 Provide Proportion of Low Income, Electrically Heated Customer Accounts in the form of Figure 5-9, P-5-13 for NIA.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.3.1.

3.0 Topic: NIA Residential Class Characteristics

Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

1.3.10 Provide Total Consumption by Household Size in the form of Figure 5-10, P-5-14 for NIA.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.3.1.

3.0 Topic: NIA Residential Class Characteristics

Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

1.3.11 Provide Customer Accounts by Household Size in the form of Figure 5-11, P-5-15 NIA.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.3.1.

3.0 Topic: NIA Residential Class Characteristics

Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

1.3.12 Provide a chart showing customer accounts by heating type for various fuel heating options for NIA.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.3.1.

3.0 Topic: NIA Residential Class Characteristics

Reference: Exhibit B-1, Section 5.2.2.2, Figures 5-2 to 5-11, P 5-8 to 5-15

Conditions in northern NIA regions (Zone II) are significantly different from Zone I due to differences in weather, distances from shopping, fuel heating alternatives, income levels, etc. This results in higher electricity consumption levels.

BC Hydro provides residential class characteristics for Zone I as determined from the F2014 REUS and billing data up to F2015.

1.3.13 Provide average summer and winter temperature data as expressed in Degree Day Deficiency or Heating Degree Day, as applicable, across all NIA and Zone I regions.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.3.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.1 Provide the range of costs per MWh for each of IPPs and NIAs.

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the requested information is not relevant to and cannot aid in the review of RDA Module 1 or the orders sought with respect to it. The requested information is not relevant to the review of the Zone I default Residential or General Service rate structures. As described on lines 13 to 15 on page 1-21 of Exhibit B-1, BC Hydro identified Zone II (NIA) as a topic that will be explored as part of Module 2 of the RDA.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.2 What is the range of costs for BC Hydro Heritage supply including Ruskin and John Hart?

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.3 Explain why there are increasing marginal costs of diesel generation.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.3.1 Provide a table of historical and forecast diesel prices from 2013 to 2016.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.4 What opportunities exist to reduce NIA generation costs and what are the constraints on implementation?

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.5 Does BC Hydro have an inventory of electric appliances in NIAs?

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.5.1 What is the penetration rate of electric space heating in NIAs?

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.5.2 Heat pumps including split zone systems?

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.5.3 Baseboard electric?

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.5.4 Electric furnaces?

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.5.5 Electric-Wood Combination furnaces?

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.6 What is the penetration rate of electric hot water tanks in the NIAs?

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.7 Are there opportunities for using the waste heat from diesel generation (hot water, space heating, etc.)?

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.8 What economic and reliable energy alternatives to electricity exist in NIAs?

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

4.0 Topic: Cost of Energy

Reference: Exhibit B-1, Appendix E, RRA 4.0; Appendix C-3B, P 259 of 609

NIA Unit Costs are reported as $254.1/MWh and IPPs are reported as $81.3/MWh.

BC Hydro states that:
"Zone II rates for higher cost of energy have not kept pace with increasing marginal costs of diesel generation."

At the same time, oil prices have fallen significantly in the last year in contrast to the statement provided by BC Hydro.

1.4.9 What economic and reliable electricity generation options exist in NIAs?

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.4.1.

5.0 Topic: DSM and Electricity Affordability

Reference: Exhibit B-1, Appendix C-3B, P 320 of 609; Exhibit B-1, Chapter 5, P 5-74-78; Table 8-6, P 8-24 to 8-27; Electricity Servicing Agreement – February 14, 2013, s. 8.1; 2014; San Diego Energy OutWest Conference "Engaging the Human Factor" and "Quality Program Services", Attachment 1 (http://www.energyoutwest.org/conference/2014-conference/2014presentations/)

"… BC Hydro plans to include information on low income Demand Side Management (DSM) programs."

"BC Hydro also provides capacity funding to non-profit housing providers and aboriginal units to assist them to hire someone locally to help promote the ESK and ECAP programs and collect application forms from tenants and/or members of the community on behalf to the two programs."

Prior to BC Hydro commencing service to Kwadacha Nation as part of the Remote Community Electrification (RCE) program, residential rates were $0.055/kWh. Now that Kwadacha Nation is in BC Hydro's service area, residential rates average $0.12-0.13/kWh. Electricity affordability is a key issue where community members rely on income assistance (average $540 monthly).

Cost of living (including food, supplies, etc.) is higher in remote communities. Remoteness contributes to higher electricity consumption due to the colder climate and the need for such things as freezers to store food since they do not have ready access to grocery stores. Also due to unemployment, multigenerational living and remoteness of the community, residents spend more time in their homes resulting in increased electricity consumption.

Some residents of the NIA communities suffer from financial and emotional stresses as a result of low income combined with high energy costs, payment difficulties and delays in implementing appropriate energy education and retrofit programs.

1.5.1 What communications, if any, has BC Hydro had to explain the reasons for the significant increase in residential rates?

RESPONSE:

BC Hydro respectfully submits that the information requested in this IR, which concerns how past rate increases were communicated to Kwadacha Nation, is not relevant to and cannot aid in the review of RDA Module 1 or the orders sought with respect to it. In particular, the requested information is not relevant to BC Hydro's proposals for default Residential and General Service rates.

Nevertheless, to be responsive, BC Hydro offers the following high level overview.

In 2013, rates and billing were discussed with Chief and Council, Aboriginal Affairs and Northern Development Canada and Band council staff. Several open houses and community sessions were conducted to provide an overview of BC Hydro rate structures and billing.

5.0 Topic: DSM and Electricity Affordability

Reference: Exhibit B-1, Appendix C-3B, P 320 of 609; Exhibit B-1, Chapter 5, P 5-74-78; Table 8-6, P 8-24 to 8-27; Electricity Servicing Agreement – February 14, 2013, s. 8.1; 2014; San Diego Energy OutWest Conference "Engaging the Human Factor" and "Quality Program Services", Attachment 1 (http://www.energyoutwest.org/conference/2014-conference/2014presentations/)

"… BC Hydro plans to include information on low income Demand Side Management (DSM) programs."
"BC Hydro also provides capacity funding to non-profit housing providers and aboriginal units to assist them to hire someone locally to help promote the ESK and ECAP programs and collect application forms from tenants and/or members of the community on behalf to the two programs."
Prior to BC Hydro commencing service to Kwadacha Nation as part of the Remote Community Electrification (RCE) program, residential rates were $0.055/kWh. Now that Kwadacha Nation is in BC Hydro's service area, residential rates average $0.12-0.13/kWh. Electricity affordability is a key issue where community members rely on income assistance (average $540 monthly).
Cost of living (including food, supplies, etc.) is higher in remote communities. Remoteness contributes to higher electricity consumption due to the colder climate and the need for such things as freezers to store food since they do not have ready access to grocery stores. Also due to unemployment, multigenerational living and remoteness of the community, residents spend more time in their homes resulting in increased electricity consumption.
Some residents of the NIA communities suffer from financial and emotional stresses as a result of low income combined with high energy costs, payment difficulties and delays in implementing appropriate energy education and retrofit programs.

1.5.2 What DSM programs are in place for NIAs? What has been the success of ESK's and ECAP to date?

RESPONSE:

With respect to the first question, BC Hydro advises that, with the exception of the Retail Rebate program which is delivered by large retail chains, all of its Residential DSM programs listed in Table 5-16 of Exhibit B-1 are available to BC Hydro Residential customers in NIAs (Rate Zone II).

With respect to the second question, as part of the 2015 RDA Module 1 stakeholder engagement BC Hydro agreed to provide low income DSM program information to provide context for the RIB rate and any examination of a low income rate (refer to the Workshop 3 consideration memo, Appendix C-3A of Exhibit B-1, pages 120 to 121 of 184). BC Hydro provided such information in section 5.6.2 of Exhibit B-1, including the number of low income households that had received ESKs since the ESK program's launch in April 2008, and the number of BC Hydro's Residential customers who have participated in ECAP since commencement of the program in May 2009.

5.0 Topic: DSM and Electricity Affordability

Reference: Exhibit B-1, Appendix C-3B, P 320 of 609; Exhibit B-1, Chapter 5, P 5-74-78; Table 8-6, P 8-24 to 8-27; Electricity Servicing Agreement – February 14, 2013, s. 8.1; 2014; San Diego Energy OutWest Conference "Engaging the Human Factor" and "Quality Program Services", Attachment 1 (http://www.energyoutwest.org/conference/2014-conference/2014presentations/)

"… BC Hydro plans to include information on low income Demand

Side Management (DSM) programs."

"BC Hydro also provides capacity funding to non-profit housing providers and aboriginal units to assist them to hire someone locally to help promote the ESK and ECAP programs and collect application forms from tenants and/or members of the community on behalf to the two programs."

Prior to BC Hydro commencing service to Kwadacha Nation as part of the Remote Community Electrification (RCE) program, residential rates were $0.055/kWh. Now that Kwadacha Nation is in BC Hydro's service area, residential rates average $0.12-0.13/kWh. Electricity affordability is a key issue where community members rely on income assistance (average $540 monthly).

Cost of living (including food, supplies, etc.) is higher in remote communities. Remoteness contributes to higher electricity consumption due to the colder climate and the need for such things as freezers to store food since they do not have ready access to grocery stores. Also due to unemployment, multigenerational living and remoteness of the community, residents spend more time in their homes resulting in increased electricity consumption.

Some residents of the NIA communities suffer from financial and emotional stresses as a result of low income combined with high energy costs, payment difficulties and delays in implementing appropriate energy education and retrofit programs.

1.5.3 What DSM programs are in place for First Nations communities?

RESPONSE:

The BC Hydro Residential DSM programs listed in Table 5-16 of Exhibit B-1 are available to BC Hydro's First Nations Residential customers (with the exception of the Retail Rebate program in NIA communities). As noted in Exhibit B-1, page 5-75, lines 21 to 24, as part of BC Hydro's low income DSM programs (ESK and ECAP), BC Hydro provides capacity funding to aboriginal units to assist them to hire someone locally to help promote the ESK and ECAP programs and collect forms from tenants and/or members of the community on behalf of the two programs.

5.0 Topic: DSM and Electricity Affordability

Reference: Exhibit B-1, Appendix C-3B, P 320 of 609; Exhibit B-1, Chapter 5, P 5-74-78; Table 8-6, P 8-24 to 8-27; Electricity Servicing Agreement – February 14, 2013, s. 8.1; 2014; San Diego Energy OutWest Conference "Engaging the Human Factor" and "Quality Program Services", Attachment 1 (http://www.energyoutwest.org/conference/2014-conference/2014presentations/)

"… BC Hydro plans to include information on low income Demand

Side Management (DSM) programs."

"BC Hydro also provides capacity funding to non-profit housing providers and aboriginal units to assist them to hire someone locally to help promote the ESK and ECAP programs and collect application forms from tenants and/or members of the community on behalf to the two programs."

Prior to BC Hydro commencing service to Kwadacha Nation as part of the Remote Community Electrification (RCE) program, residential rates were $0.055/kWh. Now that Kwadacha Nation is in BC Hydro's service area, residential rates average $0.12-0.13/kWh. Electricity affordability is a key issue where community members rely on income assistance (average $540 monthly).

Cost of living (including food, supplies, etc.) is higher in remote communities. Remoteness contributes to higher electricity consumption due to the colder climate and the need for such things as freezers to store food since they do not have ready access to grocery stores. Also due to unemployment, multigenerational living and remoteness of the community, residents spend more time in their homes resulting in increased electricity consumption.

Some residents of the NIA communities suffer from financial and emotional stresses as a result of low income combined with high energy costs, payment difficulties and delays in implementing appropriate energy education and retrofit programs.

1.5.4 What specific actions has BC Hydro taken to reduce electricity consumption in remote communities?

RESPONSE:

BC Hydro has made available the Residential DSM programs described in BC Hydro's response to Zone II IR 1.5.2.

5.0 Topic: DSM and Electricity Affordability

Reference: Exhibit B-1, Appendix C-3B, P 320 of 609; Exhibit B-1, Chapter 5, P 5-74-78; Table 8-6, P 8-24 to 8-27; Electricity Servicing Agreement – February 14, 2013, s. 8.1; 2014; San Diego Energy OutWest Conference "Engaging the Human Factor" and "Quality Program Services", Attachment 1 (http://www.energyoutwest.org/conference/2014-conference/2014presentations/)

"… BC Hydro plans to include information on low income Demand

Side Management (DSM) programs."

"BC Hydro also provides capacity funding to non-profit housing providers and aboriginal units to assist them to hire someone locally to help promote the ESK and ECAP programs and collect application forms from tenants and/or members of the community on behalf to the two programs."

Prior to BC Hydro commencing service to Kwadacha Nation as part of the Remote Community Electrification (RCE) program, residential rates were $0.055/kWh. Now that Kwadacha Nation is in BC Hydro's service area, residential rates average $0.12-0.13/kWh. Electricity affordability is a key issue where community members rely on income assistance (average $540 monthly).

Cost of living (including food, supplies, etc.) is higher in remote communities. Remoteness contributes to higher electricity consumption due to the colder climate and the need for such things as freezers to store food since they do not have ready access to grocery stores. Also due to unemployment, multigenerational living and remoteness of the community, residents spend more time in their homes resulting in increased electricity consumption.

Some residents of the NIA communities suffer from financial and emotional stresses as a result of low income combined with high energy costs, payment difficulties and delays in implementing appropriate energy education and retrofit programs.

1.5.5 What options are there for additional DSM programs for First Nations and NIA communities?

RESPONSE:

BC Hydro respectfully declines to respond to that part of the question concerning what options there may be for additional DSM programs for NIA communities on the basis that the requested information is not relevant to and cannot aid in the review of 2015 RDA Module 1 or the orders sought with respect to it:

- **As set out at Exhibit B-1, page 5-73, lines 1 to 6, DSM programs are not rates. The proper venue for examination of BC Hydro's Residential DSM programs is a section 44.2 *UCA* DSM expenditure schedule determination filing. BC Hydro will be submitting a DSM expenditure schedule filing contemporaneously with or as part of the F2017 RRA in February 2016; and**

- **Given the above, any examination of Residential DSM programs in the 2015 RDA review process must be tied to the Minister RIB Report Letter Questions 4 and 5: "What is the potential for BC Hydro's existing Residential DSM programs to mitigate RIB rate impacts on low income customers and customers without access to natural gas?" and "Within the current regulatory environment, what options are there for additional DSM programs, including low income programs?". These questions are to be answered in the context of RIB rate bill impacts. The Zone II Ratepayers Group intervention application (Exhibit C36-1) states that "Kwadacha Nation is a BC Hydro Zone II ratepayer located in Fort Ware, BC". BC Hydro confirms that Fort Ware is part of Rate Zone II. Zone II Residential customers are served pursuant to RS 1107/RS 1127 (Residential Service – Zone II) and RS 1148 (Residential Service – Zone II (Closed)), and not the RIB rate (RS 1101/RS 1121).**

Please also refer to BC Hydro's response to BCSEA IR 1.12.2.

With respect to the part of the question referencing what options there may be for additional DSM programs for First Nations, BC Hydro notes the following. Responses to Minister RIB Report Letter Questions 4 and 5 must be tailored to two Residential customer segments - low income customers and customers without access to natural gas. In addition, in BC Hydro's view, the Minister RIB Report Letter Questions 1 to 5 call for a two-phased review of BC Hydro's RIB rate. This is clear from Question 4, which asks: "What is the potential for existing [DSM] programs to mitigate these *impacts*" [emphasis added]:

- **First, is there evidence that the RIB rate has bill impacts of over 10 per cent on low income customers and customers without access to natural gas?;**

- **Second, and only if the answer to the first question is yes for one or both of the two Residential customer segments, would BC Hydro report on the potential for additional Residential DSM programs, or potential modifications to existing programs, that could be undertaken within the existing regulatory environment for one or both of these Residential customer segments.**

Please refer to BC Hydro's response to BCUC IR 1.51.1.

5.0 Topic: DSM and Electricity Affordability

Reference: Exhibit B-1, Appendix C-3B, P 320 of 609; Exhibit B-1, Chapter 5, P 5-74-78; Table 8-6, P 8-24 to 8-27; Electricity Servicing Agreement – February 14, 2013, s. 8.1; 2014; San Diego Energy OutWest Conference "Engaging the Human Factor" and "Quality Program Services", Attachment 1 (http://www.energyoutwest.org/conference/2014-conference/2014presentations/)

"… BC Hydro plans to include information on low income Demand

Side Management (DSM) programs."

"BC Hydro also provides capacity funding to non-profit housing providers and aboriginal units to assist them to hire someone locally to help promote the ESK and ECAP programs and collect application forms from tenants and/or members of the community on behalf to the two programs."

Prior to BC Hydro commencing service to Kwadacha Nation as part of the Remote Community Electrification (RCE) program, residential rates were $0.055/kWh. Now that Kwadacha Nation is in BC Hydro's service area, residential rates average $0.12-0.13/kWh. Electricity affordability is a key issue where community members rely on income assistance (average $540 monthly).

Cost of living (including food, supplies, etc.) is higher in remote communities. Remoteness contributes to higher electricity consumption due to the colder climate and the need for such things as freezers to store food since they do not have ready access to grocery stores. Also due to unemployment, multigenerational living and remoteness of the community, residents spend more time in their homes resulting in increased electricity consumption.

Some residents of the NIA communities suffer from financial and emotional stresses as a result of low income combined with high energy costs, payment difficulties and delays in implementing appropriate energy education and retrofit programs.

1.5.6 Is BC Hydro prepared to provide a BC Hydro key account/energy manager for First Nations communities to focus on DSM and supply options and work with contractors and communities on programs specific to NIAs and First Nations needs in a timely manner?

RESPONSE:

For the reasons set out in BC Hydro's response to Zone II IR 1.5.5, BC Hydro respectfully declines to respond to that part of the question concerning NIA communities on the basis that the requested information is not relevant to and cannot aid in the review of 2015 RDA Module 1 or the orders sought with respect to it.

With respect to the part of the question referencing First Nations, please refer to BC Hydro's response to Zone II IR 1.5.5. Any examination of Residential DSM programs in the 2015 RDA:

- **Is only through Minister RIB Report Letter Questions 4 and 5, and accordingly must be tailored to two Residential customer segments - low income customers and customers without access to natural gas; and**

- **Would occur only if there is evidence that the RIB rate has bill impacts of over 10 per cent on low income customers and customers without access to natural gas. In this regard, please refer to BC Hydro's response to BCUC IR 1.51.1. If the answer to this question is yes for one or both of the two Residential customer segments, BC Hydro would report on the potential for additional Residential DSM programs, or potential modifications to existing programs, that could be undertaken within the existing regulatory environment for one or both of these Residential customer segments.**

6.0 Topic: Residential Zone II (RS 1107, 1127)

Reference: Exhibit B-1, Appendix C-3B, P 258 of 609

BC Hydro states that:

"For consumption beyond 1500 kWh/month, Residential customers in Zone II pay a higher rate to discourage electric space heating from diesel-generated electricity."

NIAs do not have clean, reliable and economic heating options such as natural gas and therefore need to rely on electric space heating in some cases, including as backup. As well, residences in the NIA are not built to the same standards as homes in the Zone I area and in many cases are northern communities, resulting in increased electricity consumption.

1.6.1 Provide data showing range and average of electrical consumption for Zone II with electric heat and water by region.

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the requested information is not relevant to and cannot aid in the review of RDA Module 1 or the orders sought with respect to it. The requested information is not relevant to the review of the Zone I default Residential rate structure. As described on lines 13 to 15 on page 1-21 of Exhibit B-1, BC Hydro identified Zone II (NIA) as a topic that will be explored as part of Module 2 of the RDA.

6.0 Topic: Residential Zone II (RS 1107, 1127)

Reference: Exhibit B-1, Appendix C-3B, P 258 of 609

BC Hydro states that:

"For consumption beyond 1500 kWh/month, Residential customers in Zone II pay a higher rate to discourage electric space heating from diesel-generated electricity."

NIAs do not have clean, reliable and economic heating options such as natural gas and therefore need to rely on electric space heating in some cases, including as backup. As well, residences in the NIA are not built to the same standards as homes in the Zone I area and in many cases are northern communities, resulting in increased electricity consumption.

1.6.2 Households Provide data showing range and average electrical consumption for Zone I households with electric heat and water by region.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.6.1.

6.0 Topic: Residential Zone II (RS 1107, 1127)

Reference: Exhibit B-1, Appendix C-3B, P 258 of 609

BC Hydro states that:

"For consumption beyond 1500 kWh/month, Residential customers in Zone II pay a higher rate to discourage electric space heating from diesel-generated electricity."

NIAs do not have clean, reliable and economic heating options such as natural gas and therefore need to rely on electric space heating in some cases, including as backup. As well, residences in the NIA are not built to the same standards as homes in the Zone I area and in many cases are northern communities, resulting in increased electricity consumption.

1.6.3 Provide data showing range and average of electrical consumption for Zone II households without electric heat and water by region.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.6.1.

6.0 Topic: Residential Zone II (RS 1107, 1127)

Reference: Exhibit B-1, Appendix C-3B, P 258 of 609

BC Hydro states that:

"For consumption beyond 1500 kWh/month, Residential customers in Zone II pay a higher rate to discourage electric space heating from diesel-generated electricity."

NIAs do not have clean, reliable and economic heating options such as natural gas and therefore need to rely on electric space heating in some cases, including as backup. As well, residences in the NIA are not built to the same standards as homes in the Zone I area and in many cases are northern communities, resulting in increased electricity consumption.

1.6.4 Provide data showing range and average electrical consumption for Zone I households without electric heat and water by region.

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.6.1.

7.0 Topic: Equalizing Zone I and Zone II Residential customers

Reference: Exhibit B-1, Appendix C-3B, P 267 of 609

BC Hydro provides information on the impact of equalizing Zone II and Zone I rates and states that:

"Most Zone II residential customers would see a bill decrease, with the largest bill reductions available to the largest consumers;

Assuming no change in residential consumption behaviour, the amount of the under-recovered costs in Zone II is estimated to increase approximately $300,000...."

1.7.1 Please provide detailed information, such as bill impact data, to support the statement that "most customers would see a bill decrease".

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the requested information is not relevant to and cannot aid in the review of RDA Module 1 or the orders sought with respect to it. The requested information is not relevant to the review of the Zone I default Residential rate structure. As described on lines 13 to 15 on page 1-21 of Exhibit B-1, BC Hydro identified Zone II (NIA) as a topic that will be explored as part of Module 2 of the RDA.

7.0 Topic: Equalizing Zone I and Zone II Residential customers

Reference: Exhibit B-1, Appendix C-3B, P 267 of 609

BC Hydro provides information on the impact of equalizing Zone II and Zone I rates and states that:

"Most Zone II residential customers would see a bill decrease, with the largest bill reductions available to the largest consumers;

Assuming no change in residential consumption behaviour, the amount of the under-recovered costs in Zone II is estimated to increase approximately $300,000...."

1.7.2 Does BCH consider $300,000 to be significant and a barrier to implementing a single Residential rate?

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the requested information is not relevant to and cannot aid in the review of RDA Module 1 or the orders sought with respect to it. The requested information is not relevant to the review of the Zone I default Residential rate structure. As described on lines 13 to 15 on page 1-21 of Exhibit B-1, BC Hydro identified Zone II (NIA) as a topic that will be explored as part of Module 2 of the RDA.

8.0 Topic: General Service customers

Reference: Exhibit B-1, Appendix C-3B, Attachment 8, P 609 of 609; Appendix C-3B, P 257 of 609; Appendix C-3B, P261 of 609;

In attachment 8, BC Hydro provides information on estimated number of General Service Customers in Zone II Non-Integrated Areas, by Site Type, Region and Rate Schedule. In addition, BC Hydro states that:

"Revenues from GS customers in Zone II are near 50 percent of all Zone II revenues."

The information provided by BC Hydro is limited with respect to General Service in Zone II. In order to determine impact of General Service Rate changes on Zone II additional information on bill impacts is required.

1.8.1 Provide a comparison of Zone 1 and Zone II GS rates in the form of Figure 1, Appendix C-3B, P 261 of 609 for SGS, MGS and LGS as applicable.

RESPONSE:

BC Hydro respectfully declines to respond to this IR on the basis that the requested information is not relevant to and cannot aid in the review of RDA Module 1 or the orders sought with respect to it. The requested information is not relevant to the review of the Zone I default General Service rate structures. As described on lines 13 to 15 on page 1-21 of Exhibit B-1, BC Hydro identified Zone II (NIA) as a topic that will be explored as part of Module 2 of the RDA.

9.0 Topic: Bill Payment

Reference: Exhibit B-1, Tables 8-1 (P 8-6), 8-2 (P-7), 8-3 (P 8-8), 8-4 (P 8-12), 8-5 (P8-13), 8-6 (P8-24)

In some NIA communities there are no local banks and the closest bank may be located far away from the community. Ratepayers do not have bank accounts and do not have easy access to make bill payments to BC Hydro. BC Hydro in its proposed changes to the electric tariff terms and conditions does not propose any changes to bill payment options that recognize the unique circumstances that exist in remote communities.

1.9.1 What bill payment options are available to those ratepayers that do not have a bank account or even local access to a bank?

RESPONSE:

In communities outside the Lower Mainland, BC Hydro uses ServiceBC as a payment agent. However, it is recognized that ServiceBC does not have offices in many remote communities.

In some remote communities, BC Hydro has enabled a local business (e.g., general store) or a First Nations band office to act as a payment agent. This can be an effective method of obtaining payments from a customer without a bank account. BC Hydro Customer Service can investigate this approach if specific issues are identified.

Where residents have internet access and bank accounts, customers are encouraged to create online MyHydro accounts to receive their bills. Online payments can then be made from a bank not located in the community.

10.0 Topic: Disconnection

Reference: Exhibit B-1, Table 8-6, P8-24 to 8-27

Electricity affordability, bi-monthly billing and access to financial institutions are a key issue. The threat of disconnection is extremely disruptive and stressful for residents who have few if any heating options and have experienced significant change since BC Hydro began providing service. In addition, under Equalized Billing once an account holder on the Equal Payment Plan misses a payment or pays a lesser amount, they are moved back to the standard billing terms and may be faced with immediate payment due to BC Hydro causing additional stress. BC Hydro states in Table 8-6 (Winter Disconnects; P8-27) that:

"BC Hydro is investigating the feasibility of using smart meters to limit the allowable load to a customer. If practical, this would allow a customer facing disconnection to be provided with a minimal supply of electricity (i.e. to allow some heating) but also limit the exposure to further non-collection."

1.10.1 Please provide specifics and quantify "the minimal supply of electricity" and how that relates to an isolated northern community.

RESPONSE:

The term minimal supply electricity was used in the context of potential load limited devices as part of a winter disconnection policy. BC Hydro notes Manitoba Hydro's load limiter-related threshold implemented during its heating season of October 1 to May 14. If during that time a residential account becomes delinquent, Manitoba Hydro may install a load limiter on electric service which limits the capacity of the service to 15 amps, which Manitoba Hydro states allows enough electrical energy for a furnace to run.[1]

BC Hydro's first step has been to test the technical and process feasibility of using smart meters for this purpose. Accordingly, it has not yet undertaken detailed research or stakeholder engagement to establish an appropriate level of electrical supply if load limiting were introduced. Refer to section 5.4.4 of BC Hydro's low income terms and conditions review found as Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

[1] Manitoba Hydro, "Manitoba Hydro Affordable Energy Program", 10 November 2009, page 10 of 46; http://www.pub.gov.mb.ca/exhibits/mh2011/Volumes/app44-1.pdf.

10.0 Topic: Disconnection

Reference: Exhibit B-1, Table 8-6, P8-24 to 8-27

Electricity affordability, bi-monthly billing and access to financial institutions are a key issue. The threat of disconnection is extremely disruptive and stressful for residents who have few if any heating options and have experienced significant change since BC Hydro began providing service. In addition, under Equalized Billing once an account holder on the Equal Payment Plan misses a payment or pays a lesser amount, they are moved back to the standard billing terms and may be faced with immediate payment due to BC Hydro causing additional stress. BC Hydro states in Table 8-6 (Winter Disconnects; P8-27) that:

"BC Hydro is investigating the feasibility of using smart meters to limit the allowable load to a customer. If practical, this would allow a customer facing disconnection to be provided with a minimal supply of electricity (i.e. to allow some heating) but also limit the exposure to further non-collection."

1.10.2 For remote communities how will BC Hydro consider lack of available heating options when determining the "minimal supply of electricity"?

RESPONSE:

Please refer to BC Hydro's response to Zone II IR 1.10.1.

10.0 Topic: Disconnection

Reference: Exhibit B-1, Table 8-6, P8-24 to 8-27

Electricity affordability, bi-monthly billing and access to financial institutions are a key issue. The threat of disconnection is extremely disruptive and stressful for residents who have few if any heating options and have experienced significant change since BC Hydro began providing service. In addition, under Equalized Billing once an account holder on the Equal Payment Plan misses a payment or pays a lesser amount, they are moved back to the standard billing terms and may be faced with immediate payment due to BC Hydro causing additional stress. BC Hydro states in Table 8-6 (Winter Disconnects; P8-27) that:

"BC Hydro is investigating the feasibility of using smart meters to limit the allowable load to a customer. If practical, this would allow a customer facing disconnection to be provided with a minimal supply of electricity (i.e. to allow some heating) but also limit the exposure to further non-collection."

1.10.3 Explain "limit the exposure to further non-collection". Specify and quantify the actions with and without the "limit" BC Hydro is considering.

RESPONSE:

In this context, “limit the exposure to further non-collection” means that by restricting the use of electricity the customer is unable to significantly add to his or her outstanding balance if they don’t pay their bill. This minimizes the likelihood of incurring a bad debt write-off that is significantly higher than the outstanding balance at the time when load-limiting was enacted.

10.0 Topic: Disconnection

Reference: Exhibit B-1, Table 8-6, P8-24 to 8-27

Electricity affordability, bi-monthly billing and access to financial institutions are a key issue. The threat of disconnection is extremely disruptive and stressful for residents who have few if any heating options and have experienced significant change since BC Hydro began providing service. In addition, under Equalized Billing once an account holder on the Equal Payment Plan misses a payment or pays a lesser amount, they are moved back to the standard billing terms and may be faced with immediate payment due to BC Hydro causing additional stress. BC Hydro states in Table 8-6 (Winter Disconnects; P8-27) that:

"BC Hydro is investigating the feasibility of using smart meters to limit the allowable load to a customer. If practical, this would allow a customer facing disconnection to be provided with a minimal supply of electricity (i.e. to allow some heating) but also limit the exposure to further non-collection."

1.10.4 What other options has BC Hydro considered to address the financial and geographic differences in disconnection policies in remote communities?

RESPONSE:

Please refer to section 5.4.4 of Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

10.0 Topic: Disconnection

Reference: Exhibit B-1, Table 8-6, P8-24 to 8-27

Electricity affordability, bi-monthly billing and access to financial institutions are a key issue. The threat of disconnection is extremely disruptive and stressful for residents who have few if any heating options and have experienced significant change since BC Hydro began providing service. In addition, under Equalized Billing once an account holder on the Equal Payment Plan misses a payment or pays a lesser amount, they are moved back to the standard billing terms and may be faced with immediate payment due to BC Hydro causing additional stress. BC Hydro states in Table 8-6 (Winter Disconnects; P8-27) that:

"BC Hydro is investigating the feasibility of using smart meters to limit the allowable load to a customer. If practical, this would allow a customer facing disconnection to be provided with a minimal supply of electricity (i.e. to allow some heating) but also limit the exposure to further non-collection."

1.10.5 Will BC Hydro consider implementing a "grace period" for account holders in the event of a missed or partial payment under the Equal Payment Plan prior to moving the account holder back to standard billing?

RESPONSE:

Equal Payment Plans are not automatically cancelled as soon as a customer misses a payment or makes a partial payment. As shown in Attachment 1 of BC Hydro's response to BCOAPO IR 1.178.1, Equal Payment Plans are not cancelled until an account has been in arrears for 63 days and the outstanding balance exceeds $70.

Installment Plans are automatically cancelled when a customer misses a payment. This issue is discussed in more detail in Attachment 1 to BC Hydro's response to BCOAPO IR 1.192.1.

10.0 Topic: Disconnection

Reference: Exhibit B-1, Table 8-6, P8-24 to 8-27

Electricity affordability, bi-monthly billing and access to financial institutions are a key issue. The threat of disconnection is extremely disruptive and stressful for residents who have few if any heating options and have experienced significant change since BC Hydro began providing service. In addition, under Equalized Billing once an account holder on the Equal Payment Plan misses a payment or pays a lesser amount, they are moved back to the standard billing terms and may be faced with immediate payment due to BC Hydro causing additional stress. BC Hydro states in Table 8-6 (Winter Disconnects; P8-27) that:

"BC Hydro is investigating the feasibility of using smart meters to limit the allowable load to a customer. If practical, this would allow a customer facing disconnection to be provided with a minimal supply of electricity (i.e. to allow some heating) but also limit the exposure to further non-collection."

1.10.6 Will BC Hydro consider implementing monthly vs. bi-monthly billing in order to assist account holders for budgeting purposes?

RESPONSE:

Monthly billing is already available for residential customers that participate in the Equal Payment Plan.

BC Hydro is currently evaluating the opportunity to move additional customers to monthly billing. Monthly billing would provide customer benefits but needs to be balanced with increased bill delivery costs. There are also potential technical limitations that need to be investigated (e.g., impact of doubling volumes for generating and printing bills). However, BC Hydro acknowledges that impacts would not be large if monthly billing was targeted towards remote communities.

10.0 Topic: Disconnection

Reference: Exhibit B-1, Table 8-6, P8-24 to 8-27

Electricity affordability, bi-monthly billing and access to financial institutions are a key issue. The threat of disconnection is extremely disruptive and stressful for residents who have few if any heating options and have experienced significant change since BC Hydro began providing service. In addition, under Equalized Billing once an account holder on the Equal Payment Plan misses a payment or pays a lesser amount, they are moved back to the standard billing terms and may be faced with immediate payment due to BC Hydro causing additional stress. BC Hydro states in Table 8-6 (Winter Disconnects; P8-27) that:

"BC Hydro is investigating the feasibility of using smart meters to limit the allowable load to a customer. If practical, this would allow a customer facing disconnection to be provided with a minimal supply of electricity (i.e. to allow some heating) but also limit the exposure to further non-collection."

1.10.7 To assist residents in remote communities with high incidence of disconnection, would BC Hydro consider having a party work one-on-one with residents requiring education and other assistance or facing disconnection to develop payment solutions for the residents?

RESPONSE:

As noted in the attachment to the Zone II Ratepayers Group IRs (Exhibit C36-3), BC Hydro has previously provided educational and conservation support to remote and First Nations communities. BC Hydro continues to extend outreach to these communities, with Customer Service representatives having made 12 visits in the past year (in addition to other visits by BC Hydro Aboriginal Relations). The goals of these visits are to assist individual customers while also enabling local government with tools to support the community with billing and energy management principles.

Specific requests of this nature can be directed to BC Hydro's Aboriginal Relations or Customer Services teams.