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**VIA EMAIL**
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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

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## 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 90$^{th}$ or 95$^{th}$ 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 100$^{th}$ 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% | 2.1% | 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% |

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.